NORTHWEST NATURAL GAS CO
Form 10-Q
May 04, 2006
Table of Contents

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, 2006

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition period from __________ to __________

Commission File No. 1-15973

NORTHWEST NATURAL GAS COMPANY

(Exact name of registrant as specified in its charter)

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

220 N.W. Second Avenue, Portland, Oregon 97209

(Address of principal executive offices) (Zip Code)

Registrant s Telephone Number, including area code: (503) 226-4211

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 28, 2006, 27,576,846 shares of the registrant s Common Stock, $3-1/6 par value (the only class of Common Stock) were outstanding.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended March 31, 2006

PART I. FINANCIAL INFORMATION

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Income

(Unaudited)

Thousands, except per share amounts	**Three Months Ended March 31, 2006**	**2005**
Operating revenues:		
Gross operating revenues	$ 390,391	$ 308,777
Less: Cost of sales	255,399	180,608
Revenue taxes	9,528	7,183
Net operating revenues	125,464	120,986
Operating expenses:		
Operations and maintenance	28,247	27,195
General taxes	7,573	6,770
Depreciation and amortization	15,830	15,195
Total operating expenses	51,650	49,160
Income from operations	73,814	71,826
Other income and expense - net	518	65
Interest charges - net of amounts capitalized	9,855	9,128
Income before income taxes	64,477	62,763
Income tax expense	23,444	22,876
Net income	$ 41,033	$ 39,887
Average common shares outstanding:		
Basic	27,584	27,578
Diluted	27,632	27,863
Earnings per share of common stock:		
Basic	$ 1.49	$ 1.45
Diluted	$ 1.48	$ 1.43

See Notes to Consolidated Financial Statements

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	**March 31, 2006 (Unaudited)**	**March 31, 2005 (Unaudited)**	**Dec. 31, 2005**
Assets:			
Plant and property:			
Utility plant	$ 1,890,633	$ 1,814,991	$ 1,875,444
Less accumulated depreciation	547,635	514,785	536,867
Utility plant - net	1,342,998	1,300,206	1,338,577
Non-utility property	40,953	34,157	40,836
Less accumulated depreciation and amortization	6,221	5,408	5,990
Non-utility property - net	34,732	28,749	34,846
Total plant and property	1,377,730	1,328,955	1,373,423
Other investments	54,432	57,198	58,451
Current assets:			
Cash and cash equivalents	7,522	2,740	7,143
Accounts receivable	97,859	73,776	84,418
Accrued unbilled revenue	47,764	38,880	81,512
Allowance for uncollectible accounts	(4,526)	(3,499)	(3,067)
Gas inventory	35,906	23,139	77,256
Materials and supplies inventory	9,808	8,262	8,905
Income taxes receivable			13,234
Prepayments and other current assets	57,330	21,429	54,309
Total current assets	251,663	164,727	323,710
Regulatory assets:			
Income tax asset	66,757	65,622	65,843
Deferred environmental costs	19,196	7,231	18,880
Deferred gas costs receivable	13,522	12,978	6,974
Unamortized costs on debt redemptions	6,776	7,215	6,881
Other		6,732	
Total regulatory assets	106,251	99,778	98,578
Other assets:			
Fair value of non-trading derivatives	40,879	88,634	178,653
Other	9,102	7,305	9,216
Total other assets	49,981	95,939	187,869

Total assets	$ 1,840,057	$ 1,746,597	$ 2,042,031

See Notes to Consolidated Financial Statements

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	March 31, 2006 (Unaudited)	March 31, 2005 (Unaudited)	Dec. 31, 2005
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 87,335	$ 87,244	$ 87,334
Premium on common stock	296,281	299,900	296,471
Earnings invested in the business	237,205	214,864	205,687
Unearned stock compensation		(809)	(650)
Accumulated other comprehensive income (loss)	(1,911)	(1,818)	(1,911)
Total common stock equity	618,910	599,381	586,931
Long-term debt	501,500	483,875	521,500
Total capitalization	1,120,410	1,083,256	1,108,431
Current liabilities:			
Notes payable	50,400	10,500	126,700
Long-term debt due within one year	28,000	15,000	8,000
Accounts payable	91,185	84,693	135,287
Taxes accrued	25,876	22,074	12,725
Interest accrued	11,623	11,171	2,918
Other current and accrued liabilities	38,703	34,320	40,935
Total current liabilities	245,787	177,758	326,565
Regulatory liabilities:			
Accrued asset removal costs	173,936	157,975	169,927
Unrealized gain on non-trading derivatives, net	23,937	78,205	171,777
Customer advances	1,924	1,592	1,847
Other	4,283		661
Total regulatory liabilities	204,080	237,772	344,212
Other liabilities:			
Deferred income taxes	220,568	206,651	222,331
Deferred investment tax credits	4,479	5,155	5,069
Fair value of non-trading derivatives	17,586	10,429	6,876
Other	27,147	25,576	28,547
Total other liabilities	269,780	247,811	262,823
Commitments and contingencies (see Note 7)			
Total capitalization and liabilities	$ 1,840,057	$ 1,746,597	$ 2,042,031

See Notes to Consolidated Financial Statements

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows

(Unaudited)

Thousands	Three Months Ended March 31, 2006	2005
Operating activities:		
Net income	$ 41,033	$ 39,887
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	15,830	15,195
Deferred income taxes and investment tax credits	(3,267)	(5,822)
Undistributed earnings from equity investments	50	137
Allowance for funds used during construction	(133)	(86)
Deferred gas costs - net	(6,548)	(3,427)
Contributions to qualified defined benefit pension plans		
Non-cash expenses related to qualified defined benefit pension plans	1,441	1,159
Deferred environmental costs	(2,014)	(230)
Income from life insurance investments	(1,383)	(452)
Other	4,673	(1,790)
Changes in working capital:		
Accounts receivable - net	(11,982)	(12,077)
Accrued unbilled revenue - net	33,748	25,521
Inventories of gas, materials and supplies	40,447	35,076
Income taxes receivable	13,234	15,970
Prepayments and other current assets	(2,249)	3,644
Accounts payable	(44,102)	(17,785)
Accrued interest and taxes	21,856	20,106
Other current and accrued liabilities	(2,231)	152
Cash provided by operating activities	98,403	115,178
Investing activities:		
Investment in utility plant	(15,002)	(19,958)
Investment in non-utility property	(106)	(194)
Proceeds from sale of non-utility investments		3,001
Proceeds from life insurance	964	
Other	1,475	746
Cash used in investing activities	(12,669)	(16,405)
Financing activities:		
Common stock issued, net of expenses	859	2,569
Common stock purchased	(398)	(2,895)
Change in short-term debt	(76,300)	(92,000)
Cash dividend payments on common stock	(9,516)	(8,955)
Cash used in financing activities	(85,355)	(101,281)

Increase (decrease) in cash and cash equivalents		379		(2,508)
Cash and cash equivalents - beginning of period		7,143		5,248
Cash and cash equivalents - end of period	$	7,522	$	2,740
Supplemental disclosure of cash flow information:				
Interest paid	$	970	$	970
Income taxes paid	$		$	
Supplemental disclosure of non-cash financing activities:				
Conversions to common stock:				
7-1/4% Series of Convertible Debentures	$		$	152

See Notes to Consolidated Financial Statements

6

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Capitalization

Thousands	March 31, 2006 (Unaudited)		March 31, 2005 (Unaudited)		Dec. 31, 2005	
Common stock equity:						
Common stock	$ 87,335		$ 87,244		$ 87,334	
Premium on common stock	296,281		299,900		296,471	
Earnings invested in the business	237,205		214,864		205,687	
Unearned compensation			(809)		(650)	
Accumulated other comprehensive income (loss)	(1,911)		(1,818)		(1,911)	
Total common stock equity	618,910	55%	599,381	55%	586,931	53%
Long-term debt:						
Medium-Term Notes						
First Mortgage Bonds:						
6.340% Series B due 2005			5,000			
6.380% Series B due 2005			5,000			
6.450% Series B due 2005			5,000			
6.050% Series B due 2006	8,000		8,000		8,000	
6.310% Series B due 2007	20,000		20,000		20,000	
6.800% Series B due 2007	9,500		9,500		9,500	
6.500% Series B due 2008	5,000		5,000		5,000	
4.110% Series B due 2010	10,000		10,000		10,000	
7.450% Series B due 2010	25,000		25,000		25,000	
6.665% Series B due 2011	10,000		10,000		10,000	
7.130% Series B due 2012	40,000		40,000		40,000	
8.260% Series B due 2014	10,000		10,000		10,000	
4.700% Series B due 2015	40,000				40,000	
7.000% Series B due 2017	40,000		40,000		40,000	
6.600% Series B due 2018	22,000		22,000		22,000	
8.310% Series B due 2019	10,000		10,000		10,000	
7.630% Series B due 2019	20,000		20,000		20,000	
9.050% Series A due 2021	10,000		10,000		10,000	
5.620% Series B due 2023	40,000		40,000		40,000	
7.720% Series B due 2025	20,000		20,000		20,000	
6.520% Series B due 2025	10,000		10,000		10,000	
7.050% Series B due 2026	20,000		20,000		20,000	
7.000% Series B due 2027	20,000		20,000		20,000	
6.650% Series B due 2027	20,000		20,000		20,000	
6.650% Series B due 2028	10,000		10,000		10,000	
7.740% Series B due 2030	20,000		20,000		20,000	
7.850% Series B due 2030	10,000		10,000		10,000	
5.820% Series B due 2032	30,000		30,000		30,000	
5.660% Series B due 2033	40,000		40,000		40,000	
5.250% Series B due 2035	10,000				10,000	
Convertible Debentures						
7-1/4% Series due 2012			4,375			
	529,500		498,875		529,500	
Less long-term debt due within one year	28,000		15,000		8,000	

Total long-term debt	501,500	45%	483,875	45%	521,500	47%
Total capitalization	$ 1,120,410	100%	$ 1,083,256	100%	$ 1,108,431	100%

See Notes to Consolidated Financial Statements

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Notes to Consolidated Financial Statements

(Unaudited)

1. Basis of Financial Statements

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), a regulated utility, 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 the management of the Company 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 the Company s 2005 Annual Report on Form 10-K (2005 Form 10-K). A significant part of the business of the Company is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

Certain amounts from prior years have been reclassified to conform, for comparison purposes, with the current financial statement presentation. The current year s presentation of the Consolidated Statements of Income includes the reclassification of revenue taxes as a component of net operating revenues. Revenue taxes are expenses primarily related to the utility s franchise agreements and are based on gross operating revenues. Since revenue taxes are a direct cost of utility sales, the financial statement classification was changed to improve the presentation of net operating revenues and operating expenses. In prior years, revenue taxes were included under operating expenses as part of other taxes. The reclassifications had no impact on prior years income from operations or net income.

2. New Accounting Standards

Adopted Standards

Share Based Payment. Effective Jan. 1, 2006, we adopted Statement of Financial Accounting Standards (SFAS) No. 123R, Share Based Payment, using the Modified Prospective Application method without restatement of prior periods. Prior to implementation of SFAS No. 123R, the Company accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. SFAS No. 123R requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Under this method, the Company began to amortize compensation cost for the remaining portion of outstanding awards for which the requisite service was not yet rendered at Jan. 1, 2006. Compensation cost for these awards was based on the fair value of the awards at the grant date as determined under the intrinsic value method. The Company will determine the fair value of and account for awards that are granted, modified or settled after Jan. 1, 2006 in accordance with SFAS No. 123R. The adoption of SFAS No. 123R did not have a material impact on the Company s financial condition, results of operations or cash flows. See Note 3 for a detailed discussion of stock-based compensation.

Table of Contents

Accounting for Changes and Error Corrections. Effective Jan. 1, 2006, we adopted SFAS No. 154, Accounting for Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3, which provides guidance on the accounting for and reporting of accounting changes and error corrections. The statement requires retrospective application to prior periods financial statements of changes in accounting principles, unless it is impracticable to determine the period-specific effects or the cumulative effect of the change. The guidance provided in APB Opinion No. 20 for reporting the correction of an error in previously issued financial statements remains unchanged and requires the restatement of previously issued financial statements. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after Dec. 15, 2005. The adoption of SFAS No. 154 did not have a material impact upon the Company s financial condition, results of operation or cash flows.

Inventory Costs. Effective Jan. 1, 2006, we adopted SFAS No. 151, Inventory Costs, an amendment of ARB No. 43, Chapter 4, which amends the guidance on inventory pricing to require that abnormal amounts of idle facility expense, freight, handling costs and wasted material be charged to current period expense rather than capitalized as inventory costs. The adoption of SFAS No. 151 did not have a material impact upon the Company s financial condition, results of operations or cash flows.

Recent Accounting Pronouncements

Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the Financial Accounting Standards Board s (FASB) Emerging Issues Task Force (EITF) reached a final consensus on Issue 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. EITF 04-13 requires that two or more legally separate exchange transactions with the same counterparty be combined and considered a single arrangement for purposes of applying APB Opinion No. 29, Accounting for Nonmonetary Transactions, when the transactions are entered into in contemplation of one another. EITF 04-13 is effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006. Adoption of this standard is not expected to have a material impact on the Company s financial condition, results of operations or cash flows.

Accounting for Certain Hybrid Instruments. In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Instruments, which amends SFAS Nos. 133 and 140. 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. The statement is effective for all financial instruments acquired or issued after Jan. 1, 2007. The Company is in the process of evaluating the effect of the adoption and implementation of SFAS No. 155, which is not expected to have a material impact on its financial condition, results of operation or cash flows.

Variable Interest Entities. In April 2006, the FASB issued a staff position (FSP) interpreting variable interest entities (VIE) under FASB Interpretation No. (FIN) 46(R)-6, Determining the Variability to be Considered in Applying FIN 46(R)-6. This staff position emphasizes that preparers should use a by design approach in determining whether an interest is variable. A by design approach includes evaluating whether an interest is variable based on a thorough understanding of the design of the potential VIE, including the nature of the risks that the potential VIE was designed to create and pass along to interest holders in the entity. FSP No. FIN 46(R)-6 must be applied prospectively to all entities with which the Company first becomes involved and to all entities previously required to be analyzed under FIN 46(R) when a reconsideration event has occurred effective on or after July 1, 2006. The Company is in the process of evaluating the effect of adoption and implementation of FSP No. FIN 46(R)-6, which is not expected to have a material impact on its financial condition, results of operations or cash flows.

Table of Contents

3. Stock-Based Compensation

Effective Jan. 1, 2006, we adopted SFAS No. 123R, Share Based Payment, to account for all stock-based compensation plans. 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 in NW Natural by employees and officers, and, in the case of the NEDSCP, non-employee directors. See Part II, Item 8., Note 4, in the 2005 Form 10-K for a discussion of the Company s stock-based compensation plans.

Long-Term Incentive Plan. A total of 500,000 shares of the Company s common stock has been authorized for awards under the terms of the LTIP as stock bonus, restricted stock or performance-based stock awards. At March 31, 2006, performance-based awards on 105,000 shares, based on target, were outstanding, a restricted stock award for 5,000 shares was outstanding, and the remaining 390,000 shares are available for future grants.

Performance-based Stock Awards. At March 31, 2006, the aggregate number of performance-based shares awarded and outstanding under the Company s LTIP at the threshold, target and maximum levels were as follows:

Year Awarded	Performance Period	Threshold	Target	Maximum
2004	2004-06	6,750	27,000	54,000
2005	2005-07	8,750	35,000	70,000
2006	2006-08	10,750	43,000	86,000
	Total	26,250	105,000	210,000

For each of the performance periods shown above, awards will be based on total shareholder return relative to a peer group of gas distribution companies over the three-year performance period and on performance results relative to the Company s core and non-core strategies. For awards granted prior to Jan. 1, 2006, the Company recognizes compensation expense and liability for the LTIP awards based on performance levels achieved, and expected to be achieved, and the estimated market value of the common stock as of the distribution date. For awards granted on or after Jan. 1, 2006, the Company recognizes compensation expense in accordance with SFAS No. 123R, based on performance levels achieved and an estimated fair value using a lattice valuation model. For the quarter ended March 31, 2006, the amount accrued and expensed as compensation under the three LTIP grants was negligible. On a cumulative basis, $0.7 million, $0.6 million and a negligible amount have been accrued for the 2004-06, 2005-07 and 2006-08 performance periods, respectively.

Restricted Stock Awards. Restricted stock awards also have been granted under the LTIP. A restricted stock award consisting of 5,000 shares was granted in 2004, which will vest ratably over the period 2005-09.

Restated Stock Option Plan. The Company has reserved a total of 2,400,000 shares of Common Stock for issuance under the Restated SOP. At March 31, 2006 options on 1,132,600 shares were available for grant and options to purchase 393,700 shares were outstanding at March 31, 2006. Options are granted with an exercise price equal to the market value of the common stock at the date of grant, have 10-year terms and vest ratably over a three or four-year period following the date of grant. Shares issued under the Restated SOP upon the exercise of stock options are original issue shares. The fair value of the Company s stock-based awards were estimated as of the date of grant using the Black-Scholes option pricing model based on the following weighted-average assumptions:

	2006	**2005**
Risk-free interest rate	4.5%	4.2%
Expected life (in years)	6.2	7.0
Expected market price volatility factor	22.8%	24.6%
Expected dividend yield	4.0%	3.6%

The simplified formula for plain vanilla options was utilized to determine the expected life as defined and permitted by Staff Accounting Bulletin No. 107. The risk-free interest rate was based on the implied yield currently available on U.S. Treasury zero-coupon issues with a life equal to the expected life of the options. Historical data was employed in order to estimate the volatility factor, measured on a daily basis, for a period equal to the duration of the expected life of the option awards. The dividend yield was based on management s current estimate for dividend payout at the time of grant. A forfeiture rate of 3 percent was applied to the calculation of compensation expense.

The following table presents the effect on net income and earnings per share for outstanding stock options and stock awards prior to the adoption of SFAS No. 123R for the quarter ended March 31, 2005 in addition to the impact on reported earnings in the quarter ended March 31, 2006:

Pro Forma Effect of Stock-Based Options and ESPP:	**Three Months Ended**	
	March 31,	
Thousands, except per share amounts	**2006**	**2005**
Net income as reported	$ 41,033	$ 39,887
Add: Actual stock-based compensation expense included in reported net income under SFAS No. 123R, net of related tax effects	193	
Deduct: Pro forma stock-based compensation expense determined under the fair value based method, net of related tax effects	(193)	(92)
Pro forma earnings applicable to common stock - basic	41,033	39,795
Debenture interest less taxes		48
Pro-forma earnings applicable to common stock - diluted	$ 41,033	$ 39,843
Basic earnings per share		
As reported	$ 1.49	$ 1.45
Pro forma	$ 1.49	$ 1.44
Diluted earnings per share		
As reported	$ 1.48	$ 1.43
Pro forma	$ 1.48	$ 1.43

Table of Contents

Summarized information for stock option grants is as follows:

	Option	Price per Share	Weighted-Average
	Shares	Range	Exercise Price
Balance Outstanding, Dec. 31, 2004	431,470	$ 20.25-32.02	$ 28.38
Granted	9,000	34.95-38.30	37.18
Exercised	(121,170)	20.25-31.34	26.59
Expired	(10,800)	27.60-31.34	30.79
Balance Outstanding, Dec. 31, 2005	308,500	$ 20.25-38.30	$ 29.26
Granted	97,800	34.29	34.29
Exercised	(12,000)	20.25-31.34	24.55
Expired	(600)	31.34	31.34
Balance Outstanding, Mar. 31, 2006	393,700	$ 20.25-38.30	$ 30.65
Exercisable, Dec. 31, 2005	189,500	$ 20.25-32.02	$ 27.63
Exercisable, Mar. 31, 2006	232,850	$ 20.25-32.02	$ 28.67

The weighted-average grant-date fair value of equity awards granted during 2005 and 2006 was $7.85 and $6.29, respectively. By Dec. 31, 2006, an additional 3,000 shares will vest for a total of 235,850 exercisable shares at year-end.

During the first quarter of 2006, $0.2 million of pre-tax compensation expense related to options granted under the Restated SOP was recognized in income under the fair value method in accordance with SFAS No. 123R. In addition, less than $0.1 million of pre-tax compensation expense related to the Employee Stock Purchase Plan was recognized. As of March 31, 2006 there was $0.8 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2009.

In the first quarter of 2006, 12,000 options were exercised with a total intrinsic value of $0.1 million. Cash of $0.3 million was received for these exercises, and a negligible related tax benefit was realized. The total intrinsic value of options exercised in the first quarter of 2005 was $0.6 million, and the total fair value of options that vested in the first quarters of 2006 and 2005 was $0.3 million and $0.4 million, respectively.

The following table summarizes additional information about stock options outstanding and exercisable at March 31, 2006:

	Outstanding		Exercisable			
		(In millions)		*(In millions)*		
		Aggregate		Aggregate	Weighted-Average	Weighted-Average
	Stock	Intrinsic	Stock	Intrinsic	Exercise	Remaining
Range of Exercise Prices	Options	Value	Options	Value	Price	Life in Years
$20.25 - $38.30	393,700	$ 1.7	232,850	$ 1.4	$ 28.67	6.3

12

Table of Contents

4. Use of Derivative Instruments

NW Natural enters 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 (collectively referred to as SFAS No. 133). NW Natural utilizes derivative financial instruments to manage commodity prices related to natural gas supply requirements (see Part II, Item 8., Note 11, in the 2005 Form 10-K).

At March 31, 2006 and 2005, unrealized gains or losses from mark-to-market valuations of the Company s derivative instruments were primarily reported as regulatory liabilities or regulatory assets because regulatory mechanisms provide for the realized gains or losses at settlement to be included in utility gas costs subject to regulatory deferral treatment. The estimated fair values for unrealized gains and losses on derivative instruments outstanding, determined using a discounted cash flow model for financial swaps and physical derivatives, were as follows:

	Fair Value Gains (Losses)		
	March 31,		Dec. 31,
Thousands	**2006**	**2005**	**2005**
Fair Value Gain (Loss)			
Natural gas commodity-based derivative instruments:			
Fixed-price financial swaps	$ 26,405	$ 87,995	$ 173,790
Fixed-price financial call options			1,871
Indexed-price physical supply	(3,079)	(8,483)	(5,454)
Fixed-price physical supply		(1,429)	820
Physical supply contracts with embedded options	566		567
Foreign currency forward purchases	45	122	183
Total	$ 23,937	$ 78,205	$ 171,777

In the first quarter of 2006, NW Natural realized net gains of $17.5 million from the settlement of natural gas commodity swap and call option contracts, which were recorded as decreases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our cost of gas at settlement; therefore, no gain or loss was recorded from the settlement of those contracts.

As of March 31, 2006, all natural gas commodity price swap contracts mature no later than Oct. 31, 2008.

Table of Contents

5. Segment Information

The Company s primary business segment, Utility, consists of the distribution and sale of natural gas. Another segment, Interstate Gas Storage, represents natural gas storage services provided to interstate and intrastate customers and asset optimization activities performed by an unaffiliated energy marketing company primarily through the use of commodity transactions and releases of temporarily unused portions of NW Natural s upstream pipeline transportation capacity and gas storage capacity (see Part II, Item 8., Note 2, in the 2005 Form 10-K). The remaining segment, Other, primarily consists of non-utility operating activities and non-regulated investments.

The following table presents information about the reportable segments for the three-month periods ended March 31, 2006 and 2005. Inter-segment transactions are insignificant.

	Three Months Ended March 31,			
Thousands	**Utility**	**Interstate Gas Storage**	**Other**	**Total**
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	39,452	1,449	132	41,033
Total assets at March 31, 2006	1,792,955	35,533	11,569	1,840,057
2005				
Net operating revenues	$ 118,936	$ 2,029	$ 21	$ 120,986
Depreciation and amortization	15,031	164		15,195
Income (loss) from operations	70,168	1,693	(35)	71,826
Income (loss) from financial investments	468		(137)	331
Net income	38,844	898	145	39,887
Total assets at March 31, 2005	1,707,832	28,331	10,434	1,746,597

Table of Contents

6. Pension and Other Postretirement Benefits

Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the qualified and non-qualified pension plans and other postretirement benefit plans for the three months ended March 31, 2006 and 2005. See Part II, Item 8., Note 7, in the 2005 Form 10-K for a discussion of the assumptions used in measuring these costs and benefit obligations.

Thousands	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended March 31,			
	2006	2005	2006	2005
Service cost	$ 1,961	$ 1,589	$ 137	$ 114
Interest cost	3,758	3,263	283	308
Special termination benefits		63		
Expected return on plan assets	(4,403)	(3,530)		
Amortization of transition obligation			103	103
Amortization of prior service cost	245	223	49	
Recognized actuarial loss	916	481		72
Net periodic benefit cost	$ 2,477	$ 2,089	$ 572	$ 597

Employer Contributions

The Company is not required to make cash contributions to its qualified non-contributory defined benefit plans in 2006, but cash contributions in the form of ongoing benefit payments will be required for its unfunded non-qualified supplemental pension plans and other postretirement benefit plans in 2006. See Part II, Item 8., Note 7, in the 2005 Form 10-K for a discussion of future payments.

7. Commitments and Contingencies

Environmental Matters

NW Natural owns, or has previously owned, properties that may require environmental remediation or action. NW Natural accrues all material loss contingencies relating to these properties that it believes to be probable of assertion and reasonably estimable. The Company continues to study the extent of its 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. NW Natural regularly reviews its remediation liability for each site where it may be exposed to remediation responsibilities. The costs of environmental remediation are difficult to estimate. A number of steps are involved in each environmental remediation effort, including site investigations, remediation, operations and maintenance, monitoring and site closure. Each of these steps may, over time, involve a number of alternative actions, each of which can change the course of the effort. In certain cases, in addition to NW Natural, there are a number of other potentially responsible parties, each of which, in proceedings and negotiations with other potentially responsible parties and regulators, may influence the course of the remediation effort. The allocation of liabilities among the potentially responsible parties is often subject to dispute and highly uncertain. The events giving rise to environmental liabilities often occurred many decades ago, which complicates the determination of allocating liabilities among potentially responsible parties. Site investigations and remediation efforts often develop slowly over many years. To the extent reasonably estimable, NW Natural estimates the costs of environmental liabilities using current technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of probable cost, NW Natural records the liability at the lower end of this range. It is likely that changes in these estimates will occur throughout the remediation process for each of these sites due to uncertainty concerning NW Natural s responsibility, the complexity of environmental laws and regulations and the selection of compliance alternatives. The status of each of the sites currently under investigation is provided below. Also, see Part II, Item 8., Note 12, in the 2005 Form 10-K for a description of these properties and further discussion.

Gasco site. NW Natural owns 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 NW Natural for environmental contamination under the Oregon Department of Environmental Quality s (ODEQ) Voluntary Clean-Up Program. In June 2003, the Company 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 2006, NW Natural accrued an additional $0.2 million for the estimated cost of wells to be used as part of a pilot study for source control. The liability of $1.1 million for the Gasco site 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 (formerly Wacker) site. NW Natural previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (formerly Wacker Siltronic Corporation) (the Siltronic site). The liability balance for this site at March 31, 2006 is negligible (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 (the 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 the Company was notified that it is a potentially responsible party. 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 the Company 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. NW Natural completed the removal of the tar deposit in the Portland Harbor in October 2005 and on Nov. 5, 2005 the EPA approved the completed project. The estimated cost for the removal, including technical work, oversight, consultants, legal fees and ongoing monitoring is $10 million. To-date, NW Natural has spent $8.1 million for work related to the removal of the tar deposit with a remaining estimated liability of $1.9 million.

Oregon Steel Mills site. See Legal Proceedings, below.

Table of Contents

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the Oregon Public Utility Commission (OPUC) approved NW Natural s request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic and Portland Harbor sites. The authorization, which has been extended through January 2007 and expanded to include the Oregon Steel Mills site, allows NW Natural to defer and seek recovery of unreimbursed environmental costs in a future general rate case. In April 2006, the OPUC authorized NW Natural to accrue interest on deferred balances effective Jan. 27, 2006, subject to an annual demonstration to the OPUC that the Company has maximized its insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. As of March 31, 2006, the Company has paid a cumulative total of $14.4 million relating to the named sites since the effective date of the deferral authorization.

On a cumulative basis, NW Natural has recognized a total of $24.0 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $19.3 million has been spent to-date and $4.7 million is reported as an outstanding liability. At March 31, 2006, the Company had a regulatory asset of $19.1 million which includes $14.4 million of total expenditures to date and accruals for additional estimated costs of $4.7 million. The Company believes the recovery of these costs is probable through the regulatory process after first pursuing recovery of costs from insurance. The Company also has an insurance receivable of $1.1 million, which is not included in the regulatory asset amount. The Company intends to pursue recovery of these environmental costs from its general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. The Company considers insurance recovery probable based on a combination of factors, including a review of the terms of its 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 recent Oregon legislation that allows an insured party to seek recovery of all sums from one insurance company. The Company has not filed claims for insurance recovery nor have the insurance companies approved or denied coverage of these claims.

Legal Proceedings

The Company is 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 and in Part II, Item 8., Note 12, in the 2005 Form 10-K, cannot be predicted with certainty, the Company does not expect that the ultimate disposition of these matters will have a materially adverse effect on the Company s financial condition, results of operations or cash flows.

Industrial Customers Switching from Transportation to Sales Service. In the fourth quarter of 2005, the Company settled a dispute with some large industrial customers related to gas costs charged to such customers upon electing to receive gas commodity under sales service instead of arranging for their own supplies through independent third parties. Two formal complaints filed with the OPUC in connection with this matter have been dismissed by the OPUC. The OPUC has also closed the investigation it opened to determine whether the Company had provided adequate information about rates to the industrial customers.

On Feb. 3, 2006, Georgia-Pacific Corporation filed suit against NW Natural (Georgia-Pacific Corporation v. Northwest Natural Gas Company, Case No. CV06-151-PK, United States District Court, District of Oregon), alleging that NW Natural offered to sell natural gas to Georgia-Pacific under the interruptible sales service provisions of the Company s Rate Schedule 32 at a commodity rate set at the Company s Weighted Average Cost of Gas (WACOG). Georgia-Pacific further alleged that it accepted this offer and that the Company failed to perform as promised when, in October 2005, NW Natural notified Georgia-Pacific that it would have to charge Georgia-Pacific the incremental costs of acquiring gas on the open market. Georgia-Pacific also alleges breach of contract, promissory estoppel, fraudulent misrepresentation and breach of the duty of good faith and fair dealing. As a result, Georgia-Pacific is seeking damages in an amount to be determined at trial but which they expect to be at least $235,000, plus consequential damages in an amount to be determined at trial. Georgia-Pacific further alleges that by failing to sell gas to Georgia-Pacific at the agreed upon price, NW Natural violated Oregon state laws that regulate utility operations, thereby entitling Georgia-Pacific to treble damages and attorney fees.

Prior to the Georgia-Pacific federal lawsuit being filed, on Jan. 5, 2006, NW Natural sought a declaratory judgment in the Circuit Court for the State of Oregon (NW Natural Gas Company v. Georgia-Pacific Corporation, Case No. 0601-00116, Multnomah County) declaring that, due to the rapid rise in the cost of natural gas after hurricanes Katrina and Rita, the Company acted in accordance with its tariffs and all applicable laws when it informed Georgia-Pacific that it would not sell Georgia-Pacific natural gas at its WACOG price. When Georgia-Pacific responded by filing the federal lawsuit described above, and removing the declaratory judgment action to the federal court on Feb. 2, 2006, NW Natural voluntarily dismissed its suit for declaratory relief, and now all matters between the parties are before the federal court. NW Natural will vigorously contest the claims of Georgia-Pacific.

Independent Backhoe Operator Action. Since May 2004 five lawsuits have been filed against the Company by 11 independent backhoe operators who performed backhoe services for the Company under contract. These five lawsuits have been consolidated into one consolidated case, Law and Zuehlke, et. al. v. Northwest Natural Gas Co., CV-04-728-KI. The consolidated case consolidates the following cases previously reported: *Kerry Law and Arnold Zuehlke, on behalf of themselves and all other similarly situated v. Northwest Natural Gas Company* (Filed May 28, 2004 U.S. Dist. Ct. D. Or. Case No. CV-04-728-KI), *Ike Whittlesey, C.G. Nick Courtney, Mark Parrish, John J. Shooter, Roger Whittlesey and Philip Courtney v. Northwest Natural* (Filed February 18, 2005 U.S. Dist. Ct. D. Or. Case No. CV-05-241-KI), *Phillip Courtney v. Northwest Natural* (Filed April 12, 2005 U.S. Dist. Ct. D. Or., Case No. CV-05-507-BR), and *Kenneth Holtmann et. al. v. Northwest Natural* (Filed May 20, 2005 U.S. Dist. Ct. D. Or. Case No. 05-CV-00724-BR). The consolidated case also includes a fifth lawsuit filed on January 23, 2006, *Larry L. Luethe v. Northwest Natural* (U.S. Dist. Ct. D. Or. Case No. CV-06-098-MO).

Plaintiffs in the consolidated case are or have been independent backhoe operators who performed services for the Company under contract. 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, with the exception of the plaintiff in *Larry L. Luethe v. Northwest Natural,* plaintiffs allege that the failure to classify them as employees constituted a breach of contract and a tort under and with respect to certain unspecified employee benefits plans, programs and agreements. With the exception of the plaintiff in *Larry L. Luethe v. Northwest Natural,* plaintiffs seek 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. The Company expects that the plaintiff in *Larry L. Luethe v. Northwest Natural* will amend his complaint to include these breach of contract and tort claims for unspecified damages.

Table of Contents

In October 2005, the court granted the Company s motion to stay plaintiffs claims pending exhaustion of the administrative review process with regard to each of the plans under which plaintiffs allege that they would have been eligible to receive benefits. The litigation is still stayed pending plaintiffs exhaustion of the administrative review process. There is insufficient information at this time to reasonably estimate the range of liability, if any, from these claims. NW Natural will vigorously contest these claims and does not expect the outcome of this litigation to have a material effect on its results of operations or financial condition.

Oregon Steel Mills site. In 2004, the Company 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 the Company s predecessor, Portland Gas & Coke Company, and ten 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 the Company and other third-party defendants were denied on the basis that the failure of the Port to plead and prove that the Company was 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. The Company does not expect that the ultimate disposition of this matter will have a materially adverse affect on the Company s financial condition, results of operations or cash flows.

8. Comprehensive Income

For the three months ended March 31, 2006 and 2005, reported net income was equivalent to total comprehensive income. Items that are excluded from net income and charged directly to common stock equity are accumulated in other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss is $1.9 million at March 31, 2006, which is included in common stock equity (see Consolidated Statements of Capitalization, above).

NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

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

Northwest Natural Gas Company (NW Natural) is a natural gas services company primarily engaged in the distribution of natural gas to residential, commercial and industrial customers, operating as a regulated utility business in Oregon and southwest Washington. NW Natural also is engaged in the delivery of interstate and intrastate gas storage services, operating as a non-utility business segment principally regulated by the Federal Energy Regulatory Commission (FERC). The utility is our largest business segment with approximately 98 percent of consolidated total assets. Factors critical to the success of the utility include maintaining a safe and reliable distribution system, acquiring and distributing natural gas supplies and services at a competitive price, and being able to recover the operating and capital costs in the rates charged to customers.

The interstate gas storage segment represents approximately 2 percent of consolidated total assets. This business segment provides services to large customers using storage and transportation capacity and asset optimization services provided under an agreement with an independent energy marketing company. Factors critical to the success of our interstate gas storage segment include being able to develop additional interstate storage capacity at competitive market prices and being able to continue asset optimization services using core utility assets under a regulatory sharing agreement.

In addition to the utility and interstate gas storage business segments, the consolidated financial statements include the accounts of a wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation), and other non-regulated activities, which together are referred to in this report as our Other business segment (see Note 2).

The following is management s assessment of NW Natural s financial condition including the principal factors that affect our results of operations. The discussion refers to our consolidated activities for the three months ended March 31, 2006 and 2005. References in this discussion to Notes are to the notes to the consolidated financial statements in this report. 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 to earnings per share in this report are on the basis of diluted shares, except where noted otherwise (see Part II, Item 8., Note 1, Earnings Per Share, in the 2005 Form 10-K).

Issues and Challenges

There are a number of factors that directly affect our consolidated financial condition and results of operations. The most significant factor we face in the near term is the impact of higher gas prices. While wholesale gas prices have declined in recent months, the current forward market price for natural gas remains higher than the levels we currently have embedded in our utility customers rates, which means our customers rates are likely to increase this fall. The gas supply market tightened last year when hurricanes hit parts of the United States, and they remain tight early this year. 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 competitive advantage and our customers preference for natural gas. If higher gas prices persist, it could affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses energy needs to alternative fuel sources.

Other issues and challenges we could face in the future include unpredictable weather conditions, adverse regulatory actions or policy changes, managing gas supplies, storage and transportation capacity, managing customer growth, maintaining a competitive advantage, managing environmental risks, and managing interest rate and credit risks. For a more complete discussion of these and other risks, see Part II, Item 7., Issues, Challenges and Performance Measures, and Part I, Item 1A., Risk Factors, in the 2005 Form 10-K.

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America (GAAP), management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management s most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or using different assumptions.

Our most critical estimates or judgments involve regulatory cost recovery, unbilled revenues, derivative instruments, pension assumptions, income taxes and environmental and other contingencies (see Part II, Item 7., Application of Critical Accounting Policies and Estimates, in the 2005 Form 10-K). There have been no material changes to the information provided in our 2005 Form 10-K with respect to the application of critical accounting policies and estimates. Management has discussed its 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 $41.0 million, or $1.48 a share, for the three months ended March 31, 2006, as compared to $39.9 million, or $1.43 a share, for the same period last year. The increase in net income was attributable to improved results from our regulated utility and interstate gas storage segments. In the first quarter of 2006, we earned $39.5 million, or $1.43 a share, from utility operations representing an increase of $0.7 million, or 3 cents a share, over the prior year; and we earned $1.4 million, or 5 cents a share, from interstate gas storage operations representing an increase of $0.5 million, or 2 cents a share, over the prior year.

First quarter of 2006 compared to first quarter of 2005:

Primary factors affecting first quarter earnings this year over last year include:

- a $1.1 million, or 3 percent, increase in net income over last year due to customer growth, colder weather and gas cost savings, which were partially offset by higher operating expenses;
- net operating revenues (margin) from utility operations increased $3.4 million, or 3 percent, over last year on an 11 percent increase in total sales and transportation volumes;
- margin from residential and commercial utility customers increased $5.2 million, or 5 percent, including the effects of regulatory mechanism adjustments, on a 10 percent increase in total volumes, reflecting increases due to customer growth and colder weather;
- margin from industrial utility customers decreased $0.3 million, or 4 percent, on an 11 percent increase in total volumes, with the margin decline resulting from a temporary mark-to-market loss recognized in the current quarter;
- a positive margin contribution of $1.8 million this year, representing a sharing of utility gas cost savings under the Purchased Gas Adjustment (PGA) incentive mechanism, was equivalent to last

21

Table of Contents

- year s contribution from gas cost savings, with commodity prices for the two periods mostly hedged and included in customer rates through the annual PGA;

- a net increase of 20,967 utility customers over last year, or an annual growth rate of 3.5 percent;

- margin from interstate gas storage increased $1.1 million, or 52 percent, over last year due to increased demand for non-utility storage services and increased optimization of gas supply, storage and transportation capacity;

- total operating expenses increased $2.5 million, or 5 percent, reflecting a combination of higher operation and maintenance, general taxes and depreciation expenses largely related to customer growth, higher labor-related costs and increased utility plant assets; and

- higher income tax expense corresponding to the higher taxable income.

Dividends paid on common stock were 34.5 cents and 32.5 cents a share in the three-month periods ended March 31, 2006 and 2005, respectively. In April 2006, the Company s Board of Directors declared a dividend of 34.5 cents a share on the common stock, payable May 15, 2006, to shareholders of record on April 28, 2006. The current indicated annual dividend rate is $1.38 a share.

Results of Operations

Regulatory Developments

We provide gas utility service in Oregon and Washington, with Oregon representing over 90 percent of our utility revenues. Future earnings and cash flows from utility operations will be determined by, among other factors, our ability to obtain reasonable and timely regulatory treatment for operating expenses and investments in utility plant. See Part II, Item 7., Results of Operations Regulatory Matters, in the 2005 Form 10-K.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA mechanisms in our tariffs in Oregon and Washington to reflect changes in the costs of natural gas commodity purchased under contracts with gas producers, the application of temporary rate adjustments to amortize balances in deferred regulatory asset and liability 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 are higher than the amounts included in rates, we are not allowed to charge customers immediately for the higher costs but defer the costs and collect them in the future. Similarly, when the actual purchased gas costs are lower than the amounts included in rates, the gas cost savings are not immediately returned to customers but are deferred and refunded to customers in future periods. As part of an incentive mechanism in Oregon, we charge 33 percent of the higher cost of gas sold, or credit 33 percent of the lower cost, to earnings. In Washington, the PGA is currently based on pass-through of 100 percent of the actual cost of gas sold.

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the OPUC approved NW Natural s request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic and Portland Harbor sites. The authorization, which has been extended through January 2007 and expanded to include the Oregon Steel Mills site, allows NW Natural to defer and seek recovery of unreimbursed environmental costs in a future general rate case. In April 2006, the OPUC authorized NW Natural to accrue interest on deferred balances effective Jan. 27, 2006, subject to an annual demonstration to the OPUC that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. As of March 31, 2006, we have paid a cumulative total of $14.4 million relating to the named sites since the effective date of the deferral authorization.

Table of Contents

On a cumulative basis, NW Natural has recognized a total of $24.0 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $19.3 million has been spent to-date and $4.7 million is reported as an outstanding liability. At March 31, 2006, we had a regulatory asset of $19.1 million which includes $14.4 million of total expenditures to date and accruals for additional estimated costs of $4.7 million. We believe the recovery of these costs is probable through the regulatory process after first pursuing recovery of costs from insurance. 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 these environmental costs 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 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 recent Oregon legislation that allows an insured party to seek recovery of all sums from one insurance company. We have not filed claims for insurance recovery nor have the insurance companies approved or denied coverage of these claims.

Geo-hazard Program. We entered into a stipulation with the OPUC in 2001 for an enhanced pipeline safety program that included an accelerated bare steel replacement program and a geo-hazard safety program. The geo-hazard safety program included the identification, assessment and remediation of risks to piping infrastructure created by landslides, washouts, earthquakes or similar occurrences. The stipulation allowed NW Natural to receive deferred accounting rate treatment commencing Oct. 1, 2002, for costs associated with the programs exceeding $3 million per year. The authority to defer expenses for costs associated with the geo-hazard program expires on Dec. 31, 2006.

Utility Regulation Legislation

During 2005, the Oregon legislature passed and Oregon s Governor signed into law Senate Bill (SB) 408, effective for taxes collected on or after Jan. 1, 2006. This legislation requires the OPUC to establish an annual tax adjustment to ensure that Oregon utilities do not collect in rates more income taxes than they actually pay to government entities. See Part I, Item 1., Regulation and Rates Utility Regulation Legislation, Part IA., Risk Factors, and Part II, Item 7., Results of Operations Regulatory Matters Utility Regulation Legislation, in the 2005 Form 10-K. The OPUC continues to develop rules required to implement SB 408 and draft rules are expected to be filed by the OPUC staff in July 2006, with final adoption of rules scheduled for September 2006. Due to many uncertainties related to the OPUC s interpretations and rule making with respect to the application of the bill s provisions, we are not able to determine at this time what impact, if any, the new legislation will have on our financial condition, results of operations or cash flows, but the impact may be material.

Table of Contents

Comparison of Gas Distribution Operations

The following table summarizes the composition of utility volumes, operating revenues and margin for the three months ended March 31:

Thousands, except degree day and customer data	**2006**		**2005**	
Utility volumes - therms:				
Residential and commercial sales	253,899	62%	230,683	62%
Industrial sales and transportation	154,037	38%	138,487	38%
Total utility volumes sold and delivered	407,936	100%	369,170	100%
Utility operating revenues - dollars:				
Residential and commercial sales	$ 326,785	84%	$ 258,542	84%
Industrial sales and transportation	61,911	16%	42,991	14%
Other revenues	(1,440)	%	5,153	2%
Total utility operating revenues	$ 387,256	100%	$ 306,686	100%
Cost of gas sold	255,384		180,567	
Revenue taxes	9,528		7,183	
Utility net operating revenues (margin)	$ 122,344		$ 118,936	
Utility margin: [1]				
Residential sales	$ 78,348	64%	$ 70,055	59%
Commercial sales	31,777	26%	27,675	23%
Industrial - firm sales and transportation	3,608	3%	3,741	3%
Industrial - interruptible sales and transportation	4,878	4%	5,058	4%
Miscellaneous revenues	1,503	1%	1,898	2%
Other margin adjustments	1,440	1%	2,465	2%
Margin before regulatory mechanism adjustments	121,554	99%	110,892	93%
Weather normalization mechanism	1,842	2%	3,246	3%
Decoupling mechanism	(1,052)	(1%)	4,798	4%
Utility margin	$ 122,344	100%	$ 118,936	100%
Total number of customers (end of period)	624,297		603,330	
Actual degree days	1,814		1,769	
Percent colder (warmer) than average (25-year average degree days is used as average)	(3%)		(5%)	

(1) Amounts reported as margin for each category of customer is net of demand charges and revenue taxes. In prior years, customer margin by category did not reflect these costs but have been revised to be consistent with the current year s presentation. We believe the current presentation is a better representation of the margin earned from each class of customer.

Our utility results are affected, among other things, by customer growth and by changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In order to offset the potential volatility in utility earnings caused by these factors, we obtained OPUC approval of a conservation tariff that

Table of Contents

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 Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2005 Form 10-K).

Total utility volumes sold and delivered in the first quarter of 2006 increased 11 percent compared to the first quarter of 2005. In the three months ended March 31, 2006, weather was 3 percent colder than the comparable period in 2005, but 3 percent warmer than average.

Customer growth has continued to remain strong, with a net increase of 20,967 customers since March 31, 2005, or an annual growth rate of 3.5 percent. In the three years ended Dec. 31, 2005, more than 57,000 customers were added, representing an average annual growth rate of 3.3 percent.

Residential and Commercial Sales

Results of operations in the residential and commercial sales markets are largely impacted by seasonal weather patterns, energy prices, competition from alternative energy sources and economic conditions in our service areas. The following table summarizes the utility volumes and utility operating revenues in the residential and commercial markets for the three months ended March 31:

Thousands, except customers	**2006**	**2005**
Utility volumes - therms:		
Residential sales	176,111	158,931
Commercial sales	103,316	93,349
Change in unbilled sales	(25,528)	(21,597)
Total weather-sensitive utility volumes	253,899	230,683
Utility operating revenues - dollars:		
Residential sales	$ 238,383	$ 189,252
Commercial sales	121,700	94,422
Change in unbilled sales	(33,298)	(25,132)
Total weather-sensitive utility revenues	$ 326,785	$ 258,542
Total number of customers (end of period)	623,353	602,388

First quarter of 2006 compared to first quarter of 2005:

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

- sales volumes were 10 percent higher, reflecting the combined effect of 3 percent colder weather and 3.5 percent customer growth; and
- operating revenues were 26 percent higher due to 10 percent higher sales volumes and higher billing rates, which reflect the higher gas costs in the PGA effective Oct. 1, 2005 (see Part II, Item 7., Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, in the 2005 Form 10-K).

Typically, 80 percent or more of 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

Table of Contents

is significantly reduced due to the weather normalization mechanism in Oregon. This mechanism applies to approximately 92 percent of our Oregon customers. In Washington, our customers are not covered by a weather normalization mechanism, where approximately 10 percent of our customers are served. So the mechanism does not fully insulate us from utility earnings volatility due to weather. The mechanism contributed a net $1.8 million of margin on weather that was 3 percent warmer than normal in the three month period ended March 31, 2006, compared to $3.2 million on weather that was 5 percent warmer than normal in the first three months of 2005.

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 year-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, 2006 accrued unbilled revenue was $47.8 million compared to $38.9 million at March 31, 2005.

Industrial Sales and Transportation

The following table summarizes the delivered volumes and utility operating revenues in the industrial market for the three months ended March 31:

Thousands, except customers	**2006**	**2005**
Utility volumes - therms:		
Industrial - firm sales	24,151	21,738
Industrial - firm transportation	29,743	29,097
Industrial - interruptible sales	43,188	36,318
Industrial - interruptible transportation	56,955	51,334
Total utility volumes	154,037	138,487
Utility operating revenues - dollars:		
Industrial - firm sales	$ 23,752	$ 17,544
Industrial - firm transportation	948	1,087
Industrial - interruptible sales	35,352	22,613
Industrial - interruptible transportation	1,859	1,747
Total utility operating revenues	$ 61,911	$ 42,991
Total number of customers (end of period)	944	942

Total volumes delivered to industrial sales and transportation customers were up 15.6 million therms, or 11 percent, in the first quarter of 2006 as compared to the same period in 2005, and utility operating revenues were up $18.9 million, or 44 percent, over last year. The higher revenues reflect a shift of customers from transportation to sales service and higher billing rates due to increased gas costs. The margin contribution from industrial sales and transportation customers decreased by $0.3 million, or 4 percent, over 2005, due to a mark-to-market loss related to a temporary valuation of a gas sale contract.

Table of Contents

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 deferrals relating to gas costs (see Part II, Item 8., Note 1, Industry Regulation , in the 2005 Form 10-K). Other revenues decreased net operating revenues by $1.4 million in the first quarter of 2006, compared to an increase of $5.2 million in the first quarter of 2005. The following table summarizes other revenues by primary category for the three months ended March 31:

Thousands	2006	2005
Revenue adjustments:		
Current regulatory deferrals:		
Decoupling mechanism	$ (1,052)	$ 4,798
Weather normalization mechanism	1,569	472
South Mist pipeline extension		81
Coos Bay distribution system		605
Current regulatory amortizations:		
Decoupling mechanism	(2,688)	(839)
South Mist pipeline extension	(36)	(1,069)
Coos Bay distribution system	(480)	
Conservation programs	(674)	(888)
Year 2000 technology costs	230	(496)
Other	(3)	656
Net revenue adjustments	(3,134)	3,320
Miscellaneous revenues:		
Customer fees	1,645	1,770
Other	49	63
Total miscellaneous revenues	1,694	1,833
Total other revenues	$ (1,440)	$ 5,153

Other revenues in the three months ended March 31, 2006 were $6.6 million lower than in the three months ended March 31, 2005 primarily due to a decrease in deferrals under the decoupling mechanism ($5.9 million) and an increase in the amortization of the decoupling deferral balances ($1.8 million) partially offset by an increase in the weather normalization adjustments ($1.1 million). See Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2005 Form 10-K.

Cost of Gas Sold

Natural gas commodity prices increased significantly in recent periods, with the cost per therm of gas sold 27 percent higher in the first quarter of 2006 than the first quarter of 2005. The cost per therm sold includes current gas purchases, gas withdrawn from storage inventory, gains and losses from commodity price hedge contracts, margin from off-system gas sales, demand cost balancing adjustments, regulatory deferrals and company use (see Part II, Item 7., Results of Operations Comparison of Gas Distribution Operations Cost of Gas Sold, in the 2005 Form 10-K).

We utilize a natural gas commodity-price hedge program under the terms of our Derivatives Policy to help manage our floating price gas commodity contracts (see Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, above, and Note 4). We realized net hedge gains of $17.5 million from this program during the first quarter of 2006, compared to net losses of $1.5 million in the first three months of 2005. Gains and losses relating to the hedging of utility gas prices are included in cost of gas, which is factored into our PGA deferrals and annual rate changes, and therefore have no material impact on net income.

Table of Contents

Under our PGA tariff in Oregon, net income from Oregon operations is affected within defined limits by changes in purchased gas costs (see Part II, Item 7., Results of Operations Comparison of Gas Operations Cost of Gas Sold, in the 2005 Form 10-K). Our purchased gas costs in the first quarters of both 2006 and 2005 were lower than the costs embedded in rates, which, under the PGA sharing mechanism, increased margin by $1.8 million and $1.5 million, respectively.

We are also able to use surplus gas supplies under contract but not required for delivery to core market (residential, commercial and industrial firm) customers, due to warmer weather and other factors, to make off-system sales. Under the PGA tariff in Oregon, we retain 33 percent of the margins realized from our off-system gas sales and defer the remaining 67 percent to a regulatory asset or liability account for recovery from, or refund to, customers in future rates. Our share of margin from off-system gas sales in the first quarter of 2006 was a negligible gain compared to a gain of $0.4 million for the same period in 2005.

Business Segments Other than Gas Distribution Operations

Interstate Gas Storage

We earned net income from our non-utility interstate gas storage business segment in the three months ended March 31, 2006 of $1.4 million, after regulatory sharing and income taxes, or 5 cents a share. This compares to net income of $0.9 million or 3 cents a share in the three months ended March 31, 2005. The increase was primarily due to additional interstate storage capacity brought on line during 2006, plus an increase in revenues from our asset optimization program with an unaffiliated energy marketing company (see Part II, Item 7., Results of Operations Business Segments Other Than Local Gas Distribution Interstate Gas Storage, in the 2005 Form 10-K). The segment also began providing intrastate services in February 2006.

Our third-party optimization activities are under a contract with an unaffiliated energy marketing company, which optimizes the value of our assets by engaging in marketing activities primarily through the use of commodity transactions and releases of temporarily unused portions of our upstream pipeline transportation capacity and gas storage capacity. In Oregon, we retain 80 percent of the pre-tax income from interstate storage services and optimization of storage and pipeline transportation capacity when the costs of such capacity have not been included in utility rates, and 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 distribution to our 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 Northwest Natural s wholly-owned subsidiary, Financial Corporation (see Part II, Item 8., Note 2, Consolidated Subsidiary Operations and Segment Information, in the 2005 Form 10-K). Financial Corporation s operating results were negligible losses in the first quarters of both 2006 and 2005.

Our net investment balances in Financial Corporation at March 31, 2006 and 2005 were $3.6 and $2.8 million, respectively. The $0.8 million increase was primarily due to higher temporary cash investments, partially offset by a decline in the carrying value of long-term investments.

Table of Contents

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses in the first quarter of 2006 were $28.2 million, 4 percent higher than in the first quarter of 2005. The following summarizes the major factors that contributed to the $1.1 million increase in operations and maintenance expense:

$0.7 million increase in regular payroll-related expense resulting from pay increases and higher benefit costs;

$0.5 million increase in uncollectible accounts expense corresponding to increases in gross revenues stemming from higher rates;

$0.3 million increase in stock option expense due to the required adoption of a new rule related to share-based compensation (see Note 3);

offset, in part, by a $0.4 million decrease in injury and damage claims.

General Taxes

General taxes, which are principally comprised of property, payroll taxes and regulatory fees, increased $0.8 million, or 12 percent, in the first quarter of 2006 over the same period in 2005. Property taxes increased $0.3 million, or 8 percent, due to utility plant additions in 2006 and 2005. Regulatory fees increased $0.5 million, or 28 percent, due to increased gross operating revenues over the prior year.

Depreciation and Amortization

Depreciation and amortization expense increased by $0.6 million, or 4 percent, in the three-month period ended March 31, 2006 compared to the same period in 2005. The increased expense is primarily due to additional investments in utility property that were made to meet continuing customer growth.

Other Income and Expense Net

The following table summarizes other income and expense-net by primary components for the three months ended March 31:

Thousands	**2006**	**2005**
Gains from company-owned life insurance	$ 1,383	$ 468
Interest income	84	46
Other non-operating expense	(603)	(313)
Interest income (charges) on deferred regulatory accounts	(296)	1
Earnings from equity investments of Financial Corporation	(50)	(137)
Total other income and expense net	$ 518	$ 65

Other income and expense net was $0.5 million higher in the first quarter of 2006 compared to the first quarter of 2005. The increase was due to realized gains in the quarter from company-owned life insurance, partially offset by higher non-operating expense and higher interest charges on deferred regulatory accounts.

Table of Contents

Interest Charges Net of Amounts Capitalized

Interest charges-net of amounts capitalized in the first quarter of 2006 was $0.7 million, or 1 percent, higher than in the three months ended March 31, 2005. The increase in 2006 was due to higher balances of debt outstanding and higher interest rates during the period.

Income Taxes

The effective corporate income tax rate from operations was 36.4 percent for each of the three-month periods ended March 31, 2006 and 2005.

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). Our consolidated capital structure at March 31, 2006 and 2005 and at Dec. 31, 2005, including short-term debt, was as follows:

	March 31,		Dec. 31,
	2006	2005	2005
Common stock equity	51.6%	54.0%	47.2%
Long-term debt	41.8%	43.7%	42.0%
Short-term debt, including current maturities of long-term debt	6.6%	2.3%	10.8%
Total	100.0%	100.0%	100.0%

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.

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. Since the program s inception, we have repurchased 777,300 shares of common stock at a total cost of $23.5 million. In April 2006, NW Natural s Board of Directors extended the share repurchase 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 (see Financing Activities, below).

Liquidity and Capital Resources

At March 31, 2006, we had $7.5 million of cash and cash equivalents compared to $2.7 million at March 31, 2005 and $7.1 million at Dec. 31, 2005. 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 through Sept. 30, 2010 (see Lines of Credit, below, and Part II, Item 8., Note 6, in the 2005 Form 10-K). Short-term debt balances are typically higher at the end of December each year due to seasonal working capital requirements, which reflect the financing of accounts receivable and natural gas inventories during the winter heating season. Short-term debt balances are significantly lower at the end of March as receivables and inventories are converted into cash, which is used to reduce short-term debt.

Neither our Mortgage and Deed of Trust nor the indentures under which other 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 Derivatives Policy which require the affected party to provide substitute collateral such as cash, guaranty or letter of credit if credit ratings are lowered to non-investment grade, or in some cases if the mark-to-market value exceeds a certain threshold.

Based on the availability of short-term credit facilities and the ability to issue long-term debt and equity securities, we believe we have sufficient liquidity to satisfy our anticipated cash requirements, including the contractual obligations and investing and financing activities discussed below.

Off-Balance Sheet Arrangements

Except for certain lease and purchase commitments (see Contractual Obligations, below), we have no material off-balance sheet financing arrangements.

Contractual Obligations

Since Dec. 31, 2005, we entered into a new contract in the amount of $12.4 million for the purchase and installation of automated meter reading equipment. Other than this contract and contracts entered into in the ordinary course of business, there were no material changes to our estimated future contractual obligations during the three months ended March 31, 2006. Our contractual obligations at Dec. 31, 2005 are described in Part II, Item 7., Financial Condition Liquidity and Capital Resources Contractual Obligations, in the 2005 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 our committed bank lines of credit (see Lines of Credit, below, and Part II, Item 8., Note 6, in the 2005 Form 10-K). We had $50.4 million in commercial paper notes outstanding at March 31, 2006, compared to $10.5 million outstanding at March 31, 2005 and $126.7 million outstanding at Dec. 31, 2005. 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.

Lines of Credit

We have an agreement 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 Oct. 1, 2005 to Sept. 30, 2010.

Under the terms of these bank lines, we pay upfront fees and annual commitment fees but are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under these bank lines are based on then-current market interest rates. All principal and unpaid interest under the bank lines is due and payable on Sept. 30, 2010. There were no outstanding balances on these lines of credit at March 31, 2006 or 2005, or at Dec. 31, 2005.

Table of Contents

Credit Ratings

The table below summarizes our credit ratings from three rating agencies, Standard and Poor s Rating Services (S&P), Moody s Investors Service (Moody s) and Fitch Ratings (Fitch).

	S&P	Moody s	Fitch
Commercial paper (short-term debt)	A-1+	P-1	F1
Senior secured (long-term debt)	AA-	A2	A+
Senior unsecured (long-term debt)	A+	A3	A
Ratings outlook	Stable	Stable	Stable

Each of the rating agencies has assigned us 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 our securities. Each rating should be evaluated independently of any other rating.

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, gas prices and other 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, 2006 compared to the same period in 2005 was a decrease of $16.8 million, primarily due to a decrease in cash from working capital changes of $21.9 million. The significant factors contributing to the cash flow changes in the first quarter of 2006 compared to first quarter of 2005 are as follows:

an increase in net income added $1.1 million to cash flow;

a decrease in inventories improved cash flow by $5.4 million, primarily reflecting withdrawals of gas from storage during the winter heating season;

an increase in regulatory receivables for deferred gas costs decreased cash flow by $3.1 million, reflecting different patterns of activity between the two years with respect to purchased gas costs embedded in inventory and gas cost savings and off-system gas sales under NW Natural s PGA tariff (see Results of Operations Comparison of Gas Operations Cost of Gas Sold, above);

a decrease in accrued unbilled revenue increased cash flow by $8.2 million due to a collection of higher year-end balances, reflecting higher rates and colder weather;

an increase in accrued taxes and interest increased cash flow by $1.8 million;

a decrease in accounts payable reduced cash flow by $26.3 million due to the payment of higher year-end balances, reflecting higher gas prices and also a reduction in cash flow from financial hedge contracts;

an increase in deferred environmental costs reduced cash flow by $1.8 million;

- a decrease in other assets primarily due to an increase in regulatory liabilities and a decrease in the fair value of non-trading derivatives increased cash flow by $6.5 million;
- a decrease in income taxes receivable decreased cash flow by $2.7 million; and
- an increase in prepayments and other current assets reduced cash flow by $5.9 million.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations (see Liquidity and Capital Resources, above, and Part II, Item 8., Note 12, in the 2005 Form 10-K).

Table of Contents

Investing Activities

Cash requirements for investing activities in the first three months of 2006 totaled $12.7 million, down from $16.4 million in the same period of 2005. Cash requirements for the acquisition and construction of utility plant totaled $15.0 million, down from $20.0 million in the first quarter of 2005.

Investments in non-utility property during the first three months of 2006 totaled $0.1 million, down from $0.2 million during the first three months of 2005.

In January 2005, Financial Corporation received proceeds from the sale of its limited partnership interests in three solar electric generation projects totaling $3.0 million.

Financing Activities

Cash used in financing activities in the first three months of 2006 totaled $85.4 million, down from $101.3 million in the same period of 2005. The primary factor contributing to the $15.9 million decrease was the repayment of $76.3 million of short-term debt in the first quarter of 2006 compared to $92.0 million in the same period in 2005.

In 2000, we commenced a program to repurchase shares of our common stock through a repurchase program that has been extended through May 2007 (see Capital Structure, above). We purchased 15,600 shares in the first quarter of 2006 at a cost of $0.5 million, compared to 80,500 shares at a cost of $2.9 million in the first quarter of 2005.

Ratios of Earnings to Fixed Charges

For the three months and 12 months ended March 31, 2006 and the 12 months ended Dec. 31, 2005, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 7.23, 3.33 and 3.32, 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.

Contingencies

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with SFAS No. 5, Accounting for Contingencies. We update our estimates of loss contingencies and related disclosures when new information becomes available. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties, and we record accruals for loss contingencies based on an analysis of potential results, developed in consultation with outside counsel and consultants when appropriate. When information is sufficient to estimate only a range of potential liabilities, and no point within the range is more likely than any other, we recognize an accrued liability at the lower end of the range and disclose the range (see Note 7). It is possible, however, that the range of potential liabilities could be significantly different than amounts currently accrued and disclosed, and our financial condition and results of operations could be materially affected by changes in assumptions or estimates related to these contingencies.

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 (see Results of Operations Regulatory Developments Rate Mechanisms, above). In accordance with SFAS No. 71, 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, 2006, a cumulative $19.1 million in environmental costs has been recorded as a regulatory asset, including $14.4 million of costs paid to-date and $4.7 million of accrued estimated future environmental costs. If it is determined that both the insurance recovery and future customer rate recovery of such costs is not probable, then the costs will be charged to expense in the period such determination is made. See Note 7.

Industrial Customers Switching from Transportation to Sales Service

In the fourth quarter of 2005, we settled a dispute with some large industrial customers related to gas costs charged to such customers upon electing to receive gas commodity under sales service instead of arranging for their own supplies through independent third parties. Two formal complaints filed with the OPUC in connection with this matter have been dismissed by the OPUC. The OPUC has also closed the investigation it opened to determine whether we had provided adequate information about rates to the industrial customers. We continue to contest claims of Georgia-Pacific Corporation in a related lawsuit more fully described in Note 7.

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. 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;
- adoption and implementation by the OPUC of rules interpreting recent Oregon legislation intended to ensure that utilities do not collect in rates more income taxes than they actually pay to government entities;
- weather conditions and other natural phenomena, including earthquakes or other geo-hazard 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;

Table of Contents

- risks relating to the creditworthiness of customers, suppliers and derivative counterparties;
- risks relating to 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;
- our ability to maintain effective internal controls over financial reporting;
- 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 pension and other postretirement benefit costs;
- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions; and
- legal and administrative proceedings and settlements.

All subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NW Natural, also are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for us to predict all such factors, nor can we assess the impact of each such factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Table of Contents

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, weather risk, and interest rate risk. The following describes our exposure to these risks.

Commodity Supply Risk

We enter into short-term, medium-term and long-term natural gas supply contracts, along with associated short-, medium- and long-term transportation capacity contracts. Historically, we have taken physical delivery of at least the minimum quantities specified in our natural gas supply contracts. These contracts are primarily index-based and subject to annual re-pricing, a process that is intended to reflect anticipated market price trends during the next year. Our PGA mechanisms in Oregon and Washington provide for the recovery from customers of actual commodity costs, except that, for Oregon customers, we absorb 33 percent of the higher cost of gas sold, or retain 33 percent of the lower cost, in either case as compared to the annual PGA price built into customer rates.

Market risks related to potential adverse changes in commodity prices, foreign exchange rates or counterparty credit quality in relation to these financial and physical contracts are discussed in Part II, Item 7A., in the 2005 Form 10-K and below. Also see Note 4, above.

Credit Risk

Credit exposure to financial derivative counterparties. Based on estimated fair value, our credit exposure to financial derivative counterparties relating to commodity swap contracts was $26.4 million at March 31, 2006. Our 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. There were no credit rating downgrades for any of our counterparties during the quarter.

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 Exposure by Credit Rating Unrealized Fair Value Gain		
	March 31,		Dec. 31,
Thousands	**2006**	**2005**	**2005**
AAA/Aaa	$ 940	$	$
AA/Aa	25,465	86,376	172,315
BBB/Baa		1,619	3,346
Total	$ 26,405	$ 87,995	$ 175,661

Credit exposure to customers. Increases in the market price of natural gas are expected to increase our credit exposure to customers. Also, higher gas prices have resulted in some of our largest industrial customers switching from transportation service to sales service. Under transportation service, the customer is purchasing its commodity supplies from an independent third party, while we only provide the transportation service for delivery of that gas to the customer s premise. Under sales service, the customer is purchasing both its gas commodity supply and transportation service from us. With higher natural gas commodity prices, our credit exposure to large industrial sales customers has increased significantly. We monitor and manage the credit exposure of our industrial sales customers through credit policies and

Table of Contents

procedures, which are designed to reduce credit risk. These policies and procedures include an ongoing review of credit risks, including changes in the services provided to industrial customers as well as changes in market conditions and customers credit quality. Changes in credit risk may require us to obtain additional assurance, such as deposits, letters of credit, guarantees and prepayments to reduce our credit exposure.

We also monitor and manage the credit exposure of our residential and commercial customers. This credit risk is largely mitigated by the nature of our regulated business and reasonably short collection terms, as well as by the consistent application of credit policies and procedures.

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures
As of March 31, 2006, the principal executive officer and principal financial officer of the Company have evaluated the effectiveness of the design and operation of the Company s disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (Exchange Act)). Based upon that evaluation, the principal executive officer and principal financial officer of the Company have concluded that such disclosure controls and procedures are effective in timely alerting them to any material information relating to the Company and its consolidated subsidiaries required to be included in the Company s reports filed with or furnished to the Securities and Exchange Commission under the Exchange Act.

(b) Changes in Internal Control Over Financial Reporting
There has been no change in the Company s internal control over financial reporting that occurred during the Company s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

Table of Contents

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

For a discussion of certain pending legal proceedings, see Note 7, above.

Item 1A. RISK FACTORS

There are no material changes in risk factors in the first quarter of 2006. For a discussion of risk factors, see Part I, Item 1A., Risk Factors, in the 2005 Form 10-K.

38

Table of Contents

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table provides information about purchases by us during the quarter ended March 31, 2006 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
Balance forward			765,600	$ 11,870,463
01/01/06-01/31/06	1,630	$ 35.95		
02/01/06-02/28/06	26,040	$ 34.48		
03/01/06-03/31/06	2,789	$ 33.94	11,700	(398,001)
Total	30,459	$ 34.51	777,300	$ 11,472,462

(1) During the quarter ended March 31, 2006, 29,462 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). Prior to December 2005, the requirements of the DSPP were met by issuing original issue shares of common stock. In addition, 997 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, 2006, 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. Since the program s inception, we have repurchased 777,300 shares of common stock at a total cost of $23.5 million. In April 2006, NW Natural s Board of Directors 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.

Item 6. EXHIBITS

See Exhibit Index attached hereto.

Table of Contents

SIGNATURE

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

	NORTHWEST NATURAL GAS COMPANY
	(Registrant)
Dated: May 4, 2006	/s/ Stephen P. Feltz Stephen P. Feltz
	Principal Accounting Officer
	Treasurer and Controller

40

Table of Contents

NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX

To

Quarterly Report on Form 10-Q

For Quarter Ended

March 31, 2006

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 Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	31.1
Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002	31.2
Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.1

41