NORTHWEST NATURAL GAS CO
Form 10-Q
November 02, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended September 30, 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	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**

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

(Address of principal executive offices) (Zip Code)

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

At October 31, 2006, 27,504,896 shares of the registrant s Common Stock (the only class of Common Stock) were outstanding.

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NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended September 30, 2006

PART I. FINANCIAL INFORMATION

PART II. OTHER INFORMATION

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Income

(Unaudited)

Thousands, except per share amounts	Three Months Ended Sept. 30, 2006	Three Months Ended Sept. 30, 2005	Nine Months Ended Sept. 30, 2006	Nine Months Ended Sept. 30, 2005
Operating revenues:				
Gross operating revenues	$ 114,914	$ 106,667	$ 676,284	$ 569,111
Less: Cost of sales	70,634	62,231	431,069	335,264
Revenue taxes	2,939	2,496	16,663	13,272
Net operating revenues	41,341	41,940	228,552	220,575
Operating expenses:				
Operations and maintenance	25,640	25,988	81,796	80,164
General taxes	5,595	5,915	19,234	17,895
Depreciation and amortization	16,196	15,452	47,988	45,959
Total operating expenses	47,431	47,355	149,018	144,018
Income (loss) from operations	(6,090)	(5,415)	79,534	76,557
Other income and expense - net	314	550	1,242	1,020
Interest charges - net of amounts capitalized	9,781	9,253	28,820	27,287
Income (loss) before income taxes	(15,557)	(14,118)	51,956	50,290
Income tax expense (benefit)	(5,833)	(5,447)	18,653	17,934
Net income (loss)	$ (9,724)	$ (8,671)	$ 33,303	$ 32,356
Average common shares outstanding:				
Basic	27,556	27,560	27,568	27,564
Diluted	27,669	27,630	27,686	27,626
Earnings (loss) per share of common stock:				
Basic	$ (0.35)	$ (0.31)	$ 1.21	$ 1.17
Diluted	$ (0.35)	$ (0.31)	$ 1.20	$ 1.17

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	Sept. 30, 2006 (Unaudited)	Sept. 30, 2005 (Unaudited)	Dec. 31, 2005
Assets:			
Plant and property:			
Utility plant	$ 1,939,673	$ 1,857,053	$ 1,875,444
Less accumulated depreciation	566,972	532,667	536,867
Utility plant - net	1,372,701	1,324,386	1,338,577
Non-utility property	41,662	39,450	40,836
Less accumulated depreciation and amortization	6,684	5,755	5,990
Non-utility property - net	34,978	33,695	34,846
Total plant and property	1,407,679	1,358,081	1,373,423
Other investments	55,695	57,939	58,451
Current assets:			
Cash and cash equivalents	5,685	3,408	7,143
Accounts receivable	31,791	30,518	84,418
Accrued unbilled revenue	19,316	16,787	81,512
Allowance for uncollectible accounts	(2,060)	(1,553)	(3,067)
Gas inventory	94,808	90,961	77,256
Materials and supplies inventory	9,723	7,855	8,905
Income taxes receivable	12,052	21,145	13,234
Prepayments and other current assets	44,125	36,106	54,309
Total current assets	215,440	205,227	323,710
Regulatory assets:			
Income tax asset	66,757	65,622	65,843
Deferred environmental costs	22,836	17,456	18,880
Deferred gas costs receivable	5,183	5,414	6,974
Unamortized costs on debt redemptions	6,564	6,987	6,881
Unrealized loss on non-trading derivatives	31,317		
Other		4,182	
Total regulatory assets	132,657	99,661	98,578
Other assets:			
Fair value of non-trading derivatives	11,164	346,158	178,653
Other	8,781	8,748	9,216

Total other assets	19,945	354,906	187,869
Total assets	$ 1,831,416	$ 2,075,814	$ 2,042,031

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Balance Sheets

Thousands	Sept. 30, 2006 (Unaudited)	Sept. 30, 2005 (Unaudited)	Dec. 31, 2005
Capitalization and liabilities:			
Capitalization:			
Common stock	$ 383,897	$ 87,230	$ 87,334
Premium on common stock		296,376	296,471
Earnings invested in the business	210,457	189,417	205,687
Unearned stock compensation		(703)	(650)
Accumulated other comprehensive income (loss)	(1,911)	(1,818)	(1,911)
Total common stock equity	592,443	570,502	586,931
Long-term debt	492,000	521,500	521,500
Total capitalization	1,084,443	1,092,002	1,108,431
Current liabilities:			
Notes payable	103,300	72,500	126,700
Long-term debt due within one year	29,500	8,000	8,000
Accounts payable	64,511	81,711	135,287
Taxes accrued	12,071	10,867	12,725
Interest accrued	11,454	11,493	2,918
Other current and accrued liabilities	35,065	33,928	40,935
Total current liabilities	255,901	218,499	326,565
Regulatory liabilities:			
Accrued asset removal costs	182,725	165,917	169,927
Unrealized gain on non-trading derivatives - net		338,667	171,777
Customer advances	2,245	1,733	1,847
Other	10,054		661
Total regulatory liabilities	195,024	506,317	344,212
Other liabilities:			
Deferred income taxes	221,265	213,126	222,331
Deferred investment tax credits	4,527	5,415	5,069
Fair value of non-trading derivatives	41,469	7,491	6,876
Other	28,787	32,964	28,547
Total other liabilities	296,048	258,996	262,823
Commitments and contingencies (see Note 9)			
Total capitalization and liabilities	$ 1,831,416	$ 2,075,814	$ 2,042,031

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Cash Flows

(Unaudited)

Thousands	**Nine Months Ended Sept. 30, 2006**	**2005**
Operating activities:		
Net income	$ 33,303	$ 32,356
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	47,988	45,959
Deferred income taxes and investment tax credits	(2,522)	1,801
Undistributed earnings from equity investments	(314)	(139)
Allowance for funds used during construction	(546)	(351)
Deferred gas costs - net	1,791	4,137
Gain on sale of non-utility investments		(12)
Contributions to qualified defined benefit pension plans		(20,000)
Non-cash expenses related to qualified defined benefit pension plans	4,122	3,576
Deferred environmental costs	(4,700)	(2,128)
Income from life insurance investments	(2,196)	(1,410)
Other	9,940	(1,876)
Changes in working capital:		
Accounts receivable and accrued unbilled revenue - net	113,816	79,324
Inventories of gas, materials and supplies	(18,370)	(32,339)
Income taxes receivable	1,182	(5,175)
Prepayments and other current assets	7,421	2,730
Accounts payable	(70,776)	(20,767)
Accrued interest and taxes	7,882	9,221
Other current and accrued liabilities	(5,870)	(240)
Cash provided by operating activities	122,151	94,667
Investing activities:		
Investment in utility plant	(67,390)	(65,226)
Investment in non-utility property	(793)	(5,465)
Proceeds from sale of non-utility investments		3,001
Proceeds from life insurance	3,930	296
Other	(164)	944
Cash used in investing activities	(64,417)	(66,450)
Financing activities:		
Common stock issued, net of expenses	2,350	6,169
Common stock repurchased	(1,608)	(13,827)
Long-term debt issued		50,000
Long-term debt retired	(8,000)	(15,528)
Change in short-term debt	(23,400)	(30,000)
Cash dividend payments on common stock	(28,534)	(26,871)

Cash used in financing activities	(59,192)	(30,057)
Decrease in cash and cash equivalents	(1,458)	(1,840)
Cash and cash equivalents - beginning of period	7,143	5,248
Cash and cash equivalents - end of period	$ 5,685	$ 3,408
Supplemental disclosure of cash flow information:		
Interest paid	$ 20,293	$ 18,414
Income taxes paid	$ 20,020	$ 21,939
Supplemental disclosure of non-cash financing activities:		
Conversions to common stock:		
7-1/4 % Series of Convertible Debentures	$	$ 3,999

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Consolidated Statements of Capitalization

Thousands	Sept. 30, 2006 (Unaudited)		Sept. 30, 2005 (Unaudited)		Dec. 31, 2005	
Common stock equity:						
Common stock	$ 383,897		$ 87,230		$ 87,334	
Premium on common stock			296,376		296,471	
Earnings invested in the business	210,457		189,417		205,687	
Unearned compensation			(703)		(650)	
Accumulated other comprehensive income (loss)	(1,911)		(1,818)		(1,911)	
Total common stock equity	592,443	55%	570,502	52%	586,931	53%
Long-term debt:						
Medium-Term Notes						
First Mortgage Bonds:						
6.050% Series B due 2006			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		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		10,000	
	521,500		529,500		529,500	
Less long-term debt due within one year	29,500		8,000		8,000	
Total long-term debt	492,000	45%	521,500	48%	521,500	47%
Total capitalization	$ 1,084,443	100%	$ 1,092,002	100%	$ 1,108,431	100%

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

Notes to Consolidated Financial Statements

(Unaudited)

1. Basis of Financial Statements

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), 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 management considers necessary for a fair statement of the results for each period reported. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2005 Annual Report on Form 10-K (2005 Form 10-K). A significant part of our business is of a seasonal nature; therefore, results of operations for interim periods are not necessarily indicative of the results for a full year.

Certain amounts from prior years have been reclassified to conform, for comparison purposes, to 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 taxes other than income taxes. The reclassifications had no impact on the prior year s 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, we 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, we 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 which was determined under the intrinsic value method. We 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 our financial condition, results of operations or cash flows. See Note 4 for a discussion of stock-based compensation.

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

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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 our financial condition, results of operations 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 on our financial condition, results of operations or cash flows.

Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the Financial Accounting Standards Board (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 did not have a material impact on our financial condition, results of operations 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). This FSP 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. Consolidation of a VIE by the primary beneficiary is required if it is determined that the VIE does not effectively disperse risks among the parties involved. 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. Adoption and implementation of FSP No. FIN 46(R)-6 did not have a material impact on our financial condition, results of operations or cash flows.

Recent Accounting Pronouncements

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. We are 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 our financial condition, results of operations or cash flows.

Accounting for Uncertainty in Income Taxes. In July 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken in a tax return. Preparers must determine whether it is more-likely-than-not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. Once it is determined that a position meets the more-likely-than-not recognition threshold, the position is measured to determine the amount of benefit to recognize in the financial statements. FIN 48 applies to all tax positions related to income taxes subject to SFAS No. 109, Accounting for Income Taxes. FIN 48 is effective for fiscal years beginning after Dec. 15, 2006. We do not anticipate that the adoption of this statement will have a material effect on our financial condition, results of operations or cash flows.

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

Employers Accounting for Defined Benefit Pension and Other Postretirement Plans. In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R). SFAS No. 158 requires balance sheet recognition of the overfunded or underfunded status of pension and other postretirement benefit plans. For pension plans, the liability will be based on the projected benefit obligation (PBO). Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in accumulated other comprehensive income (AOCI) under common stock equity, net of tax, until they are amortized as a component of net periodic benefit cost. In addition, the measurement date, which is the date when plan assets and the benefit obligations are measured, is required to be the company s fiscal year end. This measurement date change will have no effect on our plan assets or benefit liabilities because we have been using our fiscal year end, December 31, as our measurement date. SFAS No. 158 is effective for us for the fiscal years ending after Dec. 15, 2006.

We are evaluating the effect of the adoption and implementation of SFAS No. 158. We intend to request regulatory deferral approval from our state commissions for deferred asset recognition of AOCI related to the funded status of certain plans under SFAS No. 71, Accounting for Certain Types of Regulation. If regulatory asset deferral of AOCI is approved, then we will recognize the change in actuarial gains and losses, prior service costs and transition assets or obligations each year as an adjustment to the regulatory AOCI asset or liability account as these amounts are recognized as components of net periodic pension costs each year. In prior years, regulatory deferral recognition was not necessary for us because we had maintained plan assets in excess of accumulated benefit obligations (ABO) for certain plans, and under the previous accounting standards the recognition of the unfunded status was not required based on PBO. Based on our unfunded obligations as of Dec. 31, 2005, the adoption of SFAS No. 158 would increase pension and postretirement liabilities by approximately $41 million, decrease deferred income tax liabilities by approximately $31 million, reduce prepayments and other current assets related to the elimination of our $37 million prepaid pension asset and decrease total common stock equity by approximately $47 million. Alternatively, if regulatory deferral is approved, our regulatory AOCI assets would increase by $47 million and total common stock equity would decrease by a negligible amount. The adoption of SFAS No. 158 is not expected to have a material impact on our results of operations or cash flows. We also do not expect adoption of SFAS No. 158 to effect our ability to meet financial debt covenants. By the time of adoption at Dec. 31, 2006, actual plan performance and actuarial assumptions could have a material impact on the actual amounts recorded.

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3. Capital Stock

In connection with the restatement of NW Natural s Restated Articles of Incorporation, effective May 31, 2006, the par value of NW Natural s common stock was eliminated. As a result, NW Natural s common stock and premium on common stock account balances are now reflected on the balance sheet as common stock.

4. 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 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).

Long-Term Incentive Plan. A total of 500,000 shares of NW Natural 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 Sept. 30, 2006, performance-based awards on 99,994 shares, based on meeting target performance levels, and restricted stock awards on 11,500 shares, including 10,500 shares subject to vesting requirements, were outstanding, with the remaining 388,506 shares available for future grants.

Performance-based Stock Awards. At Sept. 30, 2006, the aggregate number of performance-based shares awarded and outstanding under our LTIP at the threshold, target and maximum levels were as follows:

Year Awarded	**Performance Period**	**Threshold**	**Target**	**Maximum**
2004	2004-06	5,130	27,000	54,000
2005	2005-07	6,333	33,332	66,664
2006	2006-08	7,536	39,662	79,324
	Total	18,999	99,994	199,988

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 our core and non-core strategies. For awards granted prior to Jan. 1, 2006, we recognize 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, we recognize compensation expense in accordance with SFAS No. 123R, based on performance levels achieved and an estimated fair value using a binomial model. For the quarter and nine months ended Sept. 30, 2006, the amount accrued and expensed as compensation under the three LTIP grants was $0.6 million. On a cumulative basis, $0.9 million, $1.0 million and $0.1 million 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 vests ratably over the period 2005-09. On July 26, 2006, a restricted stock award was granted consisting of 6,500 shares, which will vest ratably over the period 2007-09.

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Restated Stock Option Plan. We have reserved a total of 2,400,000 shares of common stock for issuance under the Restated SOP. At Sept. 30, 2006, options on 1,134,400 shares were available for grant and options to purchase 369,600 shares were outstanding. Options are granted with an exercise price equal to the closing market price of the common stock on the day preceding 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 our stock-based awards was 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 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 based on historical experience.

During 2006, we implemented SFAS No. 123R and, therefore, the pro forma effect of stock-based options and ESPP is as reported. However, the following table presents the effect on net income and earnings per share of outstanding stock options and stock awards for the 2005 periods:

Pro Forma Effect of Stock-Based Options and ESPP:	**Three Months**	**Nine Months**
Thousands, except per share amounts	**Ended Sept. 30, 2005**	
Net income (loss) as reported	$ (8,671)	$ 32,356
Deduct: Pro forma stock-based compensation expense determined under the fair value based method - net of related tax effects	(84)	(247)
Pro forma net income (loss) - basic and diluted	$ (8,755)	$ 32,109
Basic earnings (loss) per share		
As reported	$ (0.31)	$ 1.17
Pro forma	$ (0.32)	$ 1.16
Diluted earnings (loss) per share		
As reported	$ (0.31)	$ 1.17
Pro forma	$ (0.32)	$ 1.16

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Summarized information for stock option grants is as follows:

	Option	Price per Share	
			Weighted-Average
	Shares	Range	Exercise Price
Balance Outstanding at Dec. 31, 2005	308,500	$ 20.25-38.30	$ 29.26
Granted	97,800	34.29	34.29
Exercised	(34,300)	20.25-31.34	27.20
Expired	(2,400)	31.34-34.29	32.82
Balance Outstanding at Sept. 30, 2006	369,600	$ 20.25-38.30	$ 30.76
Exercisable at Dec. 31, 2005	189,500	$ 20.25-32.02	$ 27.63
Exercisable at Sept. 30, 2006	213,700	$ 20.25-38.30	$ 28.80

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 1,000 options will vest for a total of 214,700 exercisable options at year-end, assuming no additional option exercises or forfeitures.

During the three and nine months ended Sept. 30, 2006, pre-tax compensation expense amounted to $0.1 million and $0.5 million, respectively, relating to options granted under the Restated SOP. This expense was recognized in operations and maintenance expense under the fair value method in accordance with SFAS No. 123R. In addition, $0.1 million of pre-tax compensation expense related to the ESPP was recognized for the nine months ended Sept. 30, 2006. As of Sept. 30, 2006, there was $0.5 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 nine months ended Sept. 30, 2006, 34,300 option shares were exercised with a total intrinsic value of $0.3 million. Cash of $1.1 million was received for these exercises and a $0.1 million related tax benefit was realized. The total intrinsic value of options exercised in the first nine months of 2005 was $1.2 million, and the total fair value of options that vested in the first nine months of 2006 and 2005 was $0.3 million and $0.5 million, respectively.

The following table summarizes additional information about stock options outstanding and exercisable at Sept. 30, 2006:

	Outstanding		Exercisable			
					Weighted-	Weighted-
		(In millions)		*(In millions)*		
Range of		Aggregate		Aggregate	Average	Average
Exercise	Stock	Intrinsic	Stock	Intrinsic	Exercise	Remaining
Prices	Options	Value	Options	Value	Price	Life in Years
$20.25 -38.30	369,600	$ 3.1	213,700	$ 2.2	$ 28.80	5.8

5. Long-Term Debt

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

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6. Use of Derivative Instruments

We enter into forward contracts and other related financial transactions for the purchase of natural gas that qualify as derivative instruments under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133). We primarily utilize 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 Sept. 30, 2006 and 2005, unrealized gains or losses from mark-to-market valuations of our derivative instruments were primarily reported as regulatory liabilities or regulatory assets because the realized gains or losses at settlement are included in utility gas costs, pursuant to regulatory deferral mechanisms. The estimated fair values of unrealized gains and losses on derivative instruments outstanding, determined using a discounted cash flow model, were as follows:

Thousands	Sept. 30, 2006	Sept. 30, 2005	Dec. 31, 2005
Fair Value Gain (Loss):			
Natural gas commodity-based derivative instruments:			
Fixed-price financial swaps	$ (29,122)	$ 321,119	$ 173,790
Fixed-price financial call options		19,394	1,871
Indexed-price physical supply	(2,342)	(5,281)	(5,454)
Fixed-price physical supply		3,158	820
Physical supply contracts with embedded options	43		567
Foreign currency forward purchases	104	277	183
Total	$ (31,317)	$ 338,667	$ 171,777

In the third quarter of 2006, we realized net losses of $12.4 million from the settlement of fixed-price financial swap contracts which were recorded as increases to the cost of gas, compared to net gain of $20.5 million in 2005. Realized losses were offset by lower gas purchase costs from the underlying hedged floating rate physical supply contracts. The foreign exchange gain or loss on foreign currency forward contracts is included in cost of gas at settlement; therefore, no gain or loss was recorded from the settlement of those contracts.

As of Sept. 30, 2006, all natural gas commodity price swap contracts mature no later than Oct. 31, 2008.

7. Segment Information

Our 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 temporary releases of 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. Inter-segment transactions are insignificant.

	Three Months Ended Sept. 30,				Nine Months Ended Sept. 30,			
		Interstate				Interstate		
Thousands	**Utility**	**Gas Storage**	**Other**	**Total**	**Utility**	**Gas Storage**	**Other**	**Total**
2006								
Net operating revenues	$ 38,085	$ 3,211	$ 45	$ 41,341	$ 218,476	$ 9,961	$ 115	$ 228,552
Depreciation and amortization	15,975	221		16,196	47,327	661		47,988
Income (loss) from operations	(8,634)	2,720	(176)	(6,090)	71,480	8,653	(599)	79,534
Income from financial investments	399		255	654	2,196		314	2,510
Net income (loss)	(11,408)	1,496	188	(9,724)	28,258	4,762	283	33,303
Total assets at Sept. 30, 2006	1,784,762	35,844	10,810	1,831,416	1,784,762	35,844	10,810	1,831,416
2005								
Net operating revenues	$ 38,765	$ 3,126	$ 49	$ 41,940	$ 213,377	$ 7,107	$ 91	$ 220,575
Depreciation and amortization	15,289	163		15,452	45,469	490		45,959
Income (loss) from operations	(8,196)	2,766	15	(5,415)	70,531	6,046	(20)	76,557
Income from financial investments	436		68	504	1,410		139	1,549
Net income (loss)	(10,473)	1,571	231	(8,671)	28,383	3,313	660	32,356
Total assets at Sept. 30, 2005	2,028,389	34,697	12,728	2,075,814	2,028,389	34,697	12,728	2,075,814

8. Pension and Other Postretirement Benefits

NW Natural maintains two qualified non-contributory defined benefit pension plans covering all regular employees with more than one year of service. In July 2006, the Board of Directors approved changes to the defined benefit pension plan covering non-bargaining unit employees, closing participation to any new employees hired on or after Jan. 1, 2007. For affected employees, we will provide an enhanced benefit under our existing Retirement K Savings Plan, which is a defined contribution plan under Internal Revenue Code Section 401(k).

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 (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).

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Thousands	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended Sept. 30,			
	2006	2005	2006	2005
Service cost	$ 1,784	$ 1,564	$ 142	$ 114
Interest cost	3,761	3,377	322	308
Special termination benefits		63		
Expected return on plan assets	(4,403)	(3,776)		
Amortization of transition obligation			103	103
Amortization of prior service cost	245	361	48	
Recognized actuarial loss	805	599		72
Net periodic benefit cost	$ 2,192	$ 2,188	$ 615	$ 597

Thousands	Pension Benefits		Other Postretirement Benefits	
	Nine Months Ended Sept. 30,			
	2006	2005	2006	2005
Service cost	$ 5,706	$ 4,741	$ 417	$ 342
Interest cost	11,277	9,903	888	924
Special termination benefits		189		
Expected return on plan assets	(13,210)	(10,837)		
Amortization of transition obligation			309	309
Amortization of prior service cost	735	807	146	
Recognized actuarial loss	2,638	1,562		216
Net periodic benefit cost	$ 7,146	$ 6,365	$ 1,760	$ 1,791

Employer Contributions

We are not required to make cash contributions to our qualified non-contributory defined benefit plans in 2006, but cash contributions in the form of ongoing benefit payments will be required for the 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.

9. Commitments and Contingencies

Environmental Matters

We own, or have previously owned, properties that may require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study the extent of 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. We regularly review our remediation liability for each site where we 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 and associated cost estimates. 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, we estimate 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 more likely estimate within this range of probable cost, we record 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 our 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. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (the Gasco site). We have been investigating the Gasco site for environmental contamination under the Oregon Department of Environmental Quality s (ODEQ) Voluntary Clean-Up Program. In June 2003, we filed a Feasibility Scoping Plan and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. In the third quarter of 2006, we accrued an additional $0.3 million to be used for the upgrade of the water treatment system in conjunction with source control, replacement of a well, ongoing consultant and investigation fees for in-river groundwater and source control studies and to cover cost estimates of remedial alternatives identified in the Feasibility Scoping Plan and Ecological and Human Health Risk Assessment for the most contaminated portion of the site. The liability balance at Sept. 30, 2006 is $2.7 million, which is at the low end of the probable and reasonably estimable liability range. We are not able to estimate the high end of a liability range.

Siltronic site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic site). We had previously agreed to an addendum to the Voluntary Clean-up Agreement with the ODEQ, which will require additional investigation of potential manufactured gas plant wastes on the Siltronic site. Since the scope of work is unknown, there is not enough information to reasonably estimate the additional liability. The additional amount accrued for this work in the third quarter of 2006 was negligible.

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 we were notified that we are 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). In the third quarter of 2006, we accrued an additional $0.7 million to reflect our current estimate of liability of $1.9 million related to the RI/FS for consultant fees, technical work and other costs. 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.

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In April 2004, we entered into an Administrative Order on Consent providing for early action removal of a deposit of tar in the Willamette River sediments adjacent to the Gasco site. The removal of the tar deposit in the Portland Harbor was completed in October 2005, and in November 2005, the EPA approved the completed project. In the third quarter of 2006, we accrued an additional $0.1 million to reflect our current estimate of liability of $0.9 million for costs related to the tar deposit, including oversight, consultant and legal fees, and ongoing monitoring. To date, $9.4 million has been spent for work related to the removal of the tar deposit.

Central Gas Storage Tanks. On Sept. 22, 2006, we received notice from the ODEQ that our Central Service Center has been assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas, or through historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. A negligible accrual was recorded in September 2006 for the ODEQ site assessment and legal and technical costs to investigate and determine the appropriate action, if any. We intend to seek regulatory deferral of environmental costs related to this site (see Regulatory and Insurance Recovery for Environmental Matters, below).

Oregon Steel Mills site. See Legal Proceedings, below.

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the Oregon Public Utility Commission (OPUC) approved our request for deferral of environmental costs associated with specific sites. The authorization, which has been extended through January 2007, allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. In April 2006, the OPUC authorized us 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 Sept. 30, 2006, we have paid a cumulative total of $17.1 million relating to the covered sites since the effective date of the deferral authorization.

On a cumulative basis, we have recognized a total of $27.7 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $22.0 million has been spent to-date and $5.7 million is reported as an outstanding liability. During the third quarter of 2006, we increased regulatory assets by $1.1 million for additional environmental cost estimates related to sites authorized for deferral treatment, and at Sept. 30, 2006 we had a total environmental regulatory asset of $22.8 million, which includes $17.1 million of total expenditures to date and additional accruals of $5.7 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 Oregon law, which allows an insured party to seek recovery of all sums from one insurance company. We have notified the insurance companies but have not yet filed claims for recovery, nor have the insurance companies approved or denied coverage of these claims.

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Legal Proceedings

We are subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings, including the matters described below and in Part II, Item 8., Note 12, in the 2005 Form 10-K, cannot be predicted with certainty, we do not expect that the ultimate disposition of these matters will have a material adverse effect on our financial condition, results of operations or cash flows.

Georgia-Pacific Corporation vs. Northwest Natural Gas Company. 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 we offered to sell natural gas to Georgia-Pacific under the interruptible sales service provisions of Rate Schedule 32 at a commodity rate set at our Weighted Average Cost of Gas. Georgia-Pacific further alleged that it accepted this offer and that we failed to perform as promised when, in October 2005, we notified Georgia-Pacific that we would have to charge Georgia-Pacific the incremental costs of acquiring gas on the open market. Georgia-Pacific also alleged breach of contract, promissory estoppel, fraudulent misrepresentation and breach of the duty of good faith and fair dealing.

On Feb. 23, 2006, we filed a motion for summary judgment on all claims. On June 30, 2006, an order was issued by the U.S. District Court for the District of Oregon dismissing the lawsuit with prejudice and denying all pending motions, if any, as moot. On July 27, 2006, Georgia-Pacific appealed this ruling to the Ninth Circuit Court of Appeals. We do not expect the outcome of this appeal to have a material adverse effect on our financial condition, results of operations or cash flows.

Independent Backhoe Operator Action**.** Since May 2004, five lawsuits have been filed against NW Natural by 11 independent backhoe operators who performed backhoe services for NW Natural under contract. These five lawsuits have been consolidated into one case, *Law and Zuehlke, et. al. v. Northwest Natural Gas Co.,* CV-04-728-KI, United States District Court, District of Oregon). Plaintiffs allege violation of the Fair Labor Standards Act for failure to pay overtime and also assert state wage and hour claims. Plaintiffs claim that they should have been considered employees, and seek overtime wages and interest in amounts to be determined, liquidated damages equal to the overtime award, civil penalties and attorneys fees and costs. Additionally, with one exception, plaintiffs allege that the failure to classify them as employees constituted a breach of contract and a tort under and with respect to certain employee benefits plans, programs and agreements. With the one exception, 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. We expect that the remaining plaintiff will amend his complaint to include breach of contract and tort claims for unspecified damages.

In October 2005, the court granted NW Natural 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. We will continue to vigorously contest these claims and do not expect that the outcome of this litigation will have a material adverse effect on our financial condition, results of operations or cash flows.

Oregon Steel Mills site. In 2004, we were 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 NW

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Natural s predecessor, Portland Gas & Coke Company, and ten other third-party defendants disposed of waste oil in a 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 NW Natural and other third-party defendants were denied on the basis that the failure of the Port to plead and prove that we were in violation of law was an affirmative defense that may be asserted at trial, but did not provide a sufficient basis for dismissal of the Port s claim. No date has been set for trial and discovery is ongoing. We do not expect that the ultimate disposition of this matter will have a material adverse effect on our financial condition, results of operations or cash flows.

Pipeline Safety Inspection. On Sept. 22, 2006, the Washington Utilities and Transportation Commission (WUTC) issued a Standard Natural Gas Pipeline Safety Inspection report on our facilities in Clark County, Washington. Based on the findings of the inspection report and regulatory action taken with other gas distribution companies, enforcement action is expected. We are in the process of taking corrective action and do not expect the impact of this action to have a material adverse effect on our financial condition, results of operations or cash flows.

10. Comprehensive Income

For the three and nine months ended Sept. 30, 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 included in accumulated other comprehensive income (loss), net of tax. The amount of accumulated other comprehensive loss in total common stock equity is $1.9 million at Sept. 30, 2006, which is related to our minimum pension liability (see Consolidated Statements of Capitalization, above).

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NORTHWEST NATURAL GAS COMPANY

PART I. FINANCIAL INFORMATION

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

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. 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.

We are also engaged in the delivery of interstate and intrastate gas storage services, operating as a non-utility business segment with the interstate service subject to Federal Energy Regulatory Commission (FERC) regulation. This segment, which represents approximately 2 percent of consolidated total assets, provides services to large customers using Mist storage and our transportation capacity. Asset optimization transactions are also entered into pursuant to an agreement with an independent energy marketing company. Factors critical to the ongoing success of this segment include being able to develop additional storage capacity in advance of core utility customers requirements at competitive market prices and being able to continue to optimize the value of our assets, with both storage and optimization being subject to state regulatory sharing agreements.

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 business activities, which together are referred to in this report as our Other business segment (see Note 7).

The following is management s assessment of our financial condition, including the principal factors that affect our results of operations. The discussion refers to our consolidated activities for the three and nine months ended Sept. 30, 2006 and 2005. Unless otherwise indicated, 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 issues and challenges that directly affect our consolidated financial condition and results of operations. The most significant challenge we face in the near term is managing the impact of volatile gas prices. Our gas acquisition policy and strategy has been to hedge gas prices for a significant portion of the utility s annual purchase requirements based on the market outlook and the core utility s load forecast. We generally manage gas prices using a combination of hedge strategies, including:

- negotiating fixed prices directly with gas suppliers;
- negotiating financial derivative instruments to swap from floating prices in physical supply contracts into fixed prices, or to cap the maximum ceiling prices with option contracts; and

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purchasing and injecting physical supplies into storage to be withdrawn during peak-demand winter months or to reduce spot purchase requirements when gas prices are higher during periods when market conditions are volatile.

The majority of our gas supplies come from Alberta and British Columbia, while the remainder comes from the U.S. Rocky Mountain region. We believe we have sufficient supplies of natural gas under contract to meet the needs of our firm customers, but future price increases could change our competitive advantage and our customers preference for natural gas. Higher gas prices 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 and managing environmental, interest rate and credit risks (see Part II, Item 7., Issues, Challenges and Performance Measures, Part I, Item 1A., Risk Factors, in the 2005 Form 10-K and Part II, Item 1A., Risk Factors, below).

To address some of the challenges, we recently initiated a company-wide restructuring of operations with the goal of significantly improving work processes, reducing operating expenses and capital costs and continuing to strive for excellence in customer service. Our focus has been on developing initiatives to achieve long-term strategic targets. The new operations model is expected to be implemented over the next several years and to include workforce reductions. These reductions are expected to be accomplished by primarily focusing on a combination of normal attrition and voluntary severance packages. We expect to incur costs of approximately $1.5 million to $2.0 million in the fourth quarter of 2006 related to a workforce reduction of an estimated 50-100 people, which we expect to be largely offset this year by a combination of cost reductions and gains from non-core asset sales.

Strategic Opportunities

In September 2006, we announced that we are evaluating a potential pipeline project that would connect TransCanada s Gas Transmission Northwest (GTN) interstate transmission line to our gas distribution system. We have commenced a process to determine if there is sufficient interest by potential customers to justify construction of the pipeline. If the project is determined to be viable, we would form a partnership with GTN to build and own the pipeline. We would anticipate being a large customer of the proposed pipeline and GTN would be its operator. The pipeline would be intended to provide our utility and GTN s customers with a source for more diversified delivery of gas supplies from the interstate system and enhance reliability. The decision on whether to proceed with the development of the pipeline is expected to be made in early 2007. No material contractual obligations related to the pipeline have been incurred as of Sept. 30, 2006. If constructed, commercial operation could commence by 2011.

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

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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

Three months ended Sept. 30, 2006 compared to Sept. 30, 2005:

Net income for the three months ended Sept. 30, 2006 was a loss of $9.7 million, or 35 cents per share, compared to a loss of $8.7 million, or 31 cents per share, in the same period in 2005. The loss was primarily due to results from our utility segment, which contributed a loss of $11.4 million, or 41 cents per share, to the 2006 third quarter results, compared to a loss of $10.5 million, or 38 cents per share in 2005. Net income from utility operations is typically a loss during the third quarter due to the reduced use of natural gas in the summer. Interstate gas storage operations contributed $1.5 million to earnings in the third quarter of 2006, or 5 cents per share, compared to $1.6 million, or 6 cents per share, in the same period in 2005. Other non-utility business activities resulted in net income for the quarter of $0.2 million, or 1 cent per share, in both 2006 and in 2005.

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

- an increase in utility margin from residential and commercial customers of $0.8 million, primarily resulting from annual customer growth of 3.4 percent, or 20,722 customers, largely offset by the change in the regulatory decoupling deferral due to higher than expected average use per customer;

- a decrease in utility margin from industrial customers of $0.4 million due to a few large customers switching to lower margin schedules;

- an increase in actual line loss expense of $0.4 million, which is included in cost of gas, plus a decrease in the recovery of line loss expense in rates of $0.3 million, which is reflected in lower revenues, both of which are reflected in utility margin; and

- increases in depreciation expense of $0.7 million and interest charges of $0.5 million related to the increased capital costs of serving a growing customer base, partially offset by decreases in operations and maintenance expense of $0.3 million and general taxes of $0.3 million.

Nine months ended Sept. 30, 2006 compared to Sept. 30, 2005:

For the nine months ended Sept. 30, 2006, net income increased 3 percent to $33.3 million, or $1.20 per share, compared to $32.4 million, or $1.17 per share, in the same period in 2005. Our utility operations contributed $28.2 million, or $1.02 per share, to earnings in the first nine months of 2006, compared to $28.4 million, or $1.03 per share, in 2005. Interstate gas storage operations contributed $4.8 million in the current period, or 17 cents per share, compared to $3.3 million, or 12 cents per share, in 2005. Other non-utility activities resulted in net income of $0.3 million, or 1 cent per share, compared to net income of $0.7 million, or 2 cents per share, in 2005.

Primary factors affecting year-to-date earnings this year over last year include:

- an increase in utility margin from residential and commercial customers of $11.6 million, or 7 percent, primarily resulting from customer growth and higher average use per customer, partially offset by the regulatory decoupling deferral;

a decrease in utility margin from industrial customers of $0.7 million, or 3 percent, primarily due to a combination of customers switching to lower margin schedules and a $0.2 million net loss from a temporary mark-to-market contract adjustment;

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- an increase in utility margin of $1.9 million from higher gas purchase cost savings under the regulatory Purchased Gas Adjustment (PGA) incentive mechanism;

- an increase in interstate gas storage margin of $2.9 million, or 40 percent, reflecting stronger demand for storage services and increased optimization activities; and

- an increase in total operating expenses of $5.0 million, or 3 percent, reflecting a combination of higher payroll and employee benefit costs related to wage increases and bonuses, higher depreciation and general tax expenses related to customer growth and investment in plant assets, and higher bad debt expenses related to increased gas revenues.

Dividends paid on common stock were 34.5 cents and 32.5 cents per share in the three-month periods ended Sept. 30, 2006 and 2005, respectively, and $1.035 and $0.975 per share in the nine-month periods ended Sept. 30, 2006 and 2005, respectively. In October 2006, the common stock dividend rate was increased by 3 percent to 35.5 cents per share, payable Nov. 15, 2006 to shareholders of record on Oct. 31, 2006. The current indicated annual dividend rate is $1.42 per 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 gas costs, 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 tariff mechanisms 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 accounts and the removal of temporary rate adjustments effective for the previous year. The Public Utility Commission of Oregon (OPUC) and the Washington Utilities and Transportation Commission (WUTC) approved rate increases on Oct. 25, 2006 that became effective on November 1, compared to October 1 in the prior year. The effect of the rate change is to increase the average monthly bills of Oregon residential sales customers by 3.5 percent and those of Washington residential customers by 3.0 percent.

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 required to defer a predetermined percentage of the higher costs and collect them in future rates. 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 a predetermined percentage is deferred and credited to customers in future periods. As part of an incentive mechanism in Oregon, the impact on current earnings is either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower cost of gas sold. In Washington, the PGA deferral is 100 percent of the higher or lower actual cost of gas sold.

In October 2006, the OPUC approved a modification to our PGA tariff, effective Nov. 1, 2006, which provides that we will use actual recoveries of gas costs in revenues billed (instead of using estimated gas costs incorporated in rates) compared to actual purchased gas costs to determine our PGA deferral. The effect of the new method of using actual recoveries of gas costs in amounts billed will be that any changes in line loss expense due to increases or decreases in unaccounted for gas volumes will be covered by the annual PGA mechanism, such that these increases and decreases will be reflected in the PGA deferral amounts, However, consistent with our prior PGA sharing mechanism, 67 percent of any cost of gas price differences for Oregon volumes will be deferred for refund or recovery in customer rates in subsequent periods, with the remaining 33 percent being included in current earnings.

Also in October 2006, the OPUC s annual formal review process for excess earnings was disconnected from our annual PGA filings, so that our ability to pass through 100 percent of prudently incurred gas costs into rates would not be dependent upon a determination of any excess earnings. We will continue to be subject to the same excess earnings test requirement as before, in which we are allowed to retain all of our earnings up to a threshold level equal to our authorized return on equity of 10.2 percent plus 300 basis points. Revenues equivalent to 33 percent of any earnings above the threshold are required to be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year based on movements in long-term interest rates.

Weather Normalization and Conservation Tariffs. In October 2006, the OPUC authorized a change in the annual start date for applying the weather normalization adjustment to customer bills. Previously, the start date was November 15 of each year. Now, the mechanism will start on December 1 and end on May 15 of each heating season. Also in October 2006, the OPUC authorized a change in the conservation tariff, which includes a decoupling mechanism designed to adjust margin revenues up or down to offset changes in average residential and commercial customer usage due to conservation efforts. This change, in combination with the change in our weather normalization mechanism, effectively extends the period for full decoupling from June through November of each year. Previously, full decoupling was in effect only from June through September of each year. For the remaining months of each year the decoupling mechanism is in effect but is applied only after revenues are weather normalized. These changes to our weather normalization and conservation tariffs provide for greater mitigation of our risk exposures due to variations in weather and customer consumption patterns.

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 us to receive deferred accounting rate treatment for all costs associated with the geo-hazard program. Although the authority to defer expenses for costs associated with this geo-hazard program is scheduled to expire on Dec. 31, 2006, we received approval from the OPUC to defer up to $2.5 million in 2007 related to a specific project.

Industrial Tariffs. In August 2006, the OPUC and WUTC approved tariff changes to the service options for our major industrial accounts. The changes set out additional parameters that give us more certainty in the level of gas supplies we will need to acquire to serve this customer group. The parameters include an annual election period, special pricing provisions for out-of-cycle changes and the requirement that customers on our annual weighted average cost of gas tariff complete the term of their service election.

Interstate Pipeline Rate Cases

On June 30, 2006, the two interstate pipeline companies that provide natural gas transportation to our distribution system filed general rate increase cases with FERC. Northwest Pipeline Corporation (Northwest Pipeline) filed for an overall cost of service increase of approximately $119.0 million (a 41 percent increase), including an increase in the firm transportation rate of approximately 45 percent. If approved as filed, our firm gas transportation rates would increase by approximately $17.8 million annually. The major components in the increase relate to a significant capacity replacement project, other capacity displacement projects, increased rate of return and operation and maintenance expenses, and costs associated with accounting changes to expense pipeline integrity assessment costs. FERC has accepted Northwest Pipeline s revised tariff sheets to become effective on January 1, 2007, subject to refund pending the outcome of further proceedings in the case.

GTN s rate case proposes, among other things, an approximately 71 percent increase in firm transportation rates. If approved as filed, our transportation rates on that pipeline would increase by approximately $3.1 million. The primary reason for GTN s filing was unsubscribed capacity on the

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system due to significant capacity turnback and shipper defaults. FERC has accepted and suspended the GTN rates and tariff sheets to become effective on January 1, 2007, subject to refund pending further proceedings in the case.

Increases in interstate pipeline transportation expenses are subject to our PGA deferral mechanism and are 100 percent passed-through to customers in both Oregon and Washington.

Utility Regulation Legislation

During 2005, the Oregon legislature passed Senate Bill (SB) 408 relating to taxes collected by utilities in rates 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 1A., Risk Factors, and Part II, Item 7., Results of Operations Regulatory Matters Utility Regulation Legislation, in the 2005 Form 10-K). In September 2006, the OPUC approved final rules required to implement SB 408. In October, we filed a required informational tax report comparing taxes paid to authorized to collect in rates for the fiscal years 2003, 2004 and 2005. Based on the calculations required by the final rules, our taxes paid exceeded the amount of taxes we were authorized to collect in rates by $0.6 million in 2003, $1.2 million in 2004 and $3.0 million in 2005. Because the final rules only apply to taxes collected on or after Jan. 1, 2006, there will be no adjustment to our rates as a result of this informational tax report. Although certain aspects of the final rules related to federal income tax rules are yet to be determined, we expect to file our tax report for the calendar year 2006 in October 2007, with any adjustment expected to occur in the second quarter of 2008. Based on our current corporate structure and level of non-utility investments and activities, we do not expect ongoing compliance with SB 408 to have a material adverse effect on our financial condition, results of operations or cash flows.

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Comparison of Gas Distribution Operations

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

Thousands, except degree day and customer data	Three Months Ended Sept. 30, 2006		2005	
Utility volumes - therms:				
Residential and commercial sales	54,525	29%	52,553	29%
Industrial sales and transportation	131,533	71%	128,860	71%
Total utility volumes sold and delivered	186,058	100%	181,413	100%
Utility operating revenues - dollars:				
Residential and commercial sales	$ 78,619	70%	$ 66,696	64%
Industrial sales and transportation	34,196	31%	37,319	36%
Other revenues	(1,168)	(1%)	(513)	
Total utility operating revenues	111,647	100%	103,502	100%
Cost of gas sold	70,623		62,241	
Revenue taxes	2,939		2,496	
Utility net operating revenues (margin)	$ 38,085		$ 38,765	
Utility margin:[1]				
Residential sales	$ 21,618	57%	$ 20,944	54%
Commercial sales	10,293	27%	10,182	26%
Industrial - sales and transportation	7,682	20%	8,078	21%
Miscellaneous revenues	695	2%	926	2%
Other margin adjustments	(738)	(2%)	(552)	(1%)
Margin before weather normalization and decoupling	39,550	104%	39,578	102%
Weather normalization mechanism			(2)	
Decoupling mechanism	(1,465)	(4%)	(811)	(2%)
Utility margin	$ 38,085	100%	$ 38,765	100%
Customers - end of period:				
Residential customers	562,752		543,118	
Commercial customers	59,519		58,425	
Industrial customers	937		943	
Total number of customers - end of period	623,208		602,486	
Actual degree days	79		101	
Percent colder (warmer) than average [2]	(23%)		(1%)	

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Thousands, except degree day data	Nine Months Ended Sept. 30, 2006		2005	
Utility volumes - therms:				
Residential and commercial sales	404,259	49%	382,958	48%
Industrial sales and transportation	419,313	51%	407,365	52%
Total utility volumes sold and delivered	823,572	100%	790,323	100%
Utility operating revenues - dollars:				
Residential and commercial sales	$ 533,584	80%	$ 439,497	78%
Industrial sales and transportation	133,775	20%	117,125	21%
Other revenues	(1,206)	0%	5,213	1%
Total utility operating revenues	666,153	100%	561,835	100%
Cost of gas sold	431,014		335,186	
Revenue taxes	16,663		13,272	
Utility net operating revenues (margin)	$ 218,476		$ 213,377	
Utility margin:(1)				
Residential sales	$ 133,522	61%	$ 125,356	59%
Commercial sales	55,769	26%	52,374	24%
Industrial - sales and transportation	23,872	11%	24,605	12%
Miscellaneous revenues	3,343	2%	4,046	2%
Other margin adjustments	2,684	1%	2,464	1%
Margin before weather normalization and decoupling	219,190	101%	208,845	98%
Weather normalization mechanism	2,686	1%	2,516	1%
Decoupling mechanism	(3,400)	(2%)	2,016	1%
Utility margin	$ 218,476	100%	$ 213,377	100%
Actual degree days	2,465		2,522	
Percent colder (warmer) than average(2)	(7%)		(5%)	

(1) Amounts reported as margin for each category 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. See Note 1.

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

Our utility results are affected by, among other things, customer growth and changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In order to offset the potential volatility in utility earnings caused by these factors, we obtained OPUC approval of a conservation tariff that adjusts margin up or down based on changes in residential and commercial customer consumption and a weather normalization mechanism that adjusts customer bills, and our margin, based on above- or below-average temperatures during the winter heating season (see Regulatory Developments Rate Mechanisms, above and Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2005 Form 10-K).

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Three months and nine months ended Sept. 30, 2006 compared to Sept. 30, 2005:

Total utility volumes sold and delivered in the third quarter this year increased by 3 percent over last year, while total utility margin decreased by 2 percent. Total utility volumes sold and delivered in the first nine months of this year increased by 4 percent over last year, while total utility margin increased by 2 percent. Volume increases in both the current three- and nine-month periods were due mainly to industrial usage and customer growth, which has continued to remain strong with a net increase of 20,722 customers since Sept. 30, 2005, or an annual growth rate of 3.4 percent. Margin changes in the current three- and nine-month periods were below the volume increases, primarily due to lower industrial margins (see Industrial Sales and Transportation, below).

Residential and Commercial Sales

Residential and commercial sales markets are impacted by seasonal weather patterns, energy prices, competition from alternative energy sources and economic conditions in our service areas. Typically, 80 percent or more of annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced due to the weather normalization mechanisms in Oregon where about 90 percent of our customers are served. Approximately 10 percent of our eligible customers have opted out of the mechanism. In Oregon, we also have a conservation decoupling mechanism that is intended to break the link between our earnings and the quantity of gas consumed by our customers, so that we do not have an incentive to discourage customers from conserving energy. In Washington, where the remaining 10 percent of our customers are served, we do not have a weather normalization or decoupling mechanism. As a result, the mechanisms do not fully insulate the utility from earnings volatility due to weather. See the tables above for the adjustments to utility margin revenues from the weather normalization and decoupling mechanisms for the three- and nine- month periods ended Sept. 30, 2006 and 2005.

The following table summarizes the utility volumes and utility operating revenues in the residential and commercial markets:

	Three Months Ended		Nine Months Ended	
	Sept. 30,		Sept. 30,	
Thousands	**2006**	**2005**	**2006**	**2005**
Utility volumes - therms:				
Residential sales	27,348	27,877	275,506	258,377
Commercial sales	25,535	25,574	177,146	166,431
Change in unbilled sales	1,642	(898)	(48,393)	(41,850)
Total weather-sensitive utility volumes	54,525	52,553	404,259	382,958
Utility operating revenues - dollars:				
Residential sales	$ 44,954	$ 40,324	$ 384,145	$ 316,463
Commercial sales	31,926	27,372	210,489	169,598
Change in unbilled sales	1,739	(1,000)	(61,050)	(46,564)
Total weather-sensitive utility revenues	$ 78,619	$ 66,696	$ 533,584	$ 439,497

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Three months ended Sept. 30, 2006 compared to Sept. 30, 2005:

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

- sales volumes were 4 percent higher as a result of customer growth and slightly higher average use per customer; and
- operating revenues were 18 percent higher due to 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).

Nine months ended Sept. 30, 2006 compared to Sept. 30, 2005:

The primary factors affecting residential and commercial volumes and operating revenues year-to-date this year over last year include:

- sales volumes were 6 percent higher, mainly resulting from customer growth and colder weather in the first quarter when heating degree days have a larger impact on customer usage; and
- operating revenues were 21 percent higher due to customer growth, 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), and colder weather in the first quarter of 2006 compared to the same period in 2005 when the effect of weather is greater, slightly offset by the smaller incremental effect of warmer weather in the second and third quarters of 2006 compared to the same periods in 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 period end. Weather conditions, rate changes and customer billing dates affect the balance of accrued unbilled revenues at the end of each month. At Sept. 30, 2006, accrued unbilled revenue was $19.3 million compared to $16.8 million at Sept. 30, 2005.

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Industrial Sales and Transportation

The following table summarizes the delivered volumes and utility operating revenues in the industrial market:

	Three Months Ended		Nine Months Ended	
	Sept. 30,		Sept. 30,	
Thousands	**2006**	**2005**	**2006**	**2005**
Utility volumes - therms:				
Industrial - firm sales	12,211	14,855	52,286	53,416
Industrial - firm transportation	39,391	33,398	104,482	99,710
Industrial - interruptible sales	21,340	35,303	89,784	106,751
Industrial - interruptible transportation	57,872	44,675	173,185	147,836
Change in unbilled sales	719	629	(424)	(348)
Total utility volumes	131,533	128,860	419,313	407,365
Utility operating revenues - dollars:				
Industrial - firm sales	$ 12,269	$ 12,238	$ 51,425	$ 43,285
Industrial - firm transportation	1,328	941	3,445	3,055
Industrial - interruptible sales	17,691	21,846	73,427	65,835
Industrial - interruptible transportation	2,020	1,742	5,747	5,234
Change in unbilled sales	888	552	(269)	(284)
Total utility operating revenues	$ 34,196	$ 37,319	$ 133,775	$ 117,125

Three months ended Sept. 30, 2006 compared to Sept. 30, 2005:

Total volumes delivered to industrial sales and transportation customers were up 2.7 million therms, or 2 percent, in the third quarter of 2006 as compared to the same period in 2005. Utility operating revenues were down $3.1 million, or 8 percent, over last year. The lower operating revenues primarily reflect the transfer of a few large customers from sales service last year to transportation service this year, with the cost of gas sold to these customers included in sales revenues last year but not this year, and a higher percentage of volumes in lower margin rate schedules in 2006 compared to 2005.

Nine months ended Sept. 30, 2006 compared to Sept. 30, 2005:

Total volumes delivered to industrial sales and transportation customers were up 11.9 million therms, or 3 percent, in the nine months ended Sept. 30, 2006, compared to the same period in 2005. Utility operating revenues were up $16.7 million, or 14 percent, over last year. The higher revenues primarily reflect the higher volumes delivered and the higher billing rates to industrial sales customers due to increased gas costs, partially offset by the transfer of a few large customers from sales service last year to transportation service this year. The margin contribution from industrial sales and transportation decreased by $0.7 million, or 3 percent, over 2005, primarily due to customers switching to lower margin contracts or rate schedules and a temporary $0.2 million net loss mark-to-market adjustment related to the valuation of a gas sales contract, partially offset by higher delivered volumes.

Other Revenues

Other revenues include miscellaneous fee income as well as utility revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferred gas costs (see Part II, Item 8., Note 1, Industry Regulation, in the 2005 Form 10-K). Other revenues

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decreased net operating revenues by $1.2 million in the third quarter of 2006, compared to a decrease of $0.5 million in the third quarter of 2005. In the first nine months of 2006, other revenues decreased net operating revenues by $1.2 million, compared to an increase of $5.2 million in the first nine months of 2005. The following table summarizes other revenues by major category:

	Three Months Ended		Nine Months Ended	
	Sept. 30,		Sept. 30,	
Thousands	**2006**	**2005**	**2006**	**2005**
Revenue adjustments:				
Current regulatory deferrals:				
Decoupling mechanism	$ (1,465)	$ (811)	$ (3,400)	$ 2,016
Weather normalization mechanism		(3)	234	(36)
South Mist pipeline extension		(129)		164
Coos Bay distribution system		111		814
Current regulatory amortizations:				
Interstate gas storage credits			4,051	2,714
Decoupling mechanism	(475)	(180)	(4,304)	(1,416)
South Mist pipeline extension	(7)	(221)	(58)	(1,789)
Coos Bay distribution system	(101)		(794)	
Conservation programs	(146)	(222)	(1,124)	(1,551)
Other	46	16	370	251
Net revenue adjustments	(2,148)	(1,439)	(5,025)	1,167
Miscellaneous revenues:				
Customer fees	306	509	3,027	3,530
Other	674	417	792	516
Total miscellaneous revenues	980	926	3,819	4,046
Total other revenues	$ (1,168)	$ (513)	$ (1,206)	$ 5,213

Three months ended Sept. 30, 2006 compared to Sept. 30, 2005:

Other revenues in the three months ended Sept. 30, 2006 were $0.7 million lower than in the three months ended Sept. 30, 2005 primarily due to a $0.7 million change in the current decoupling deferral.

Nine months ended Sept. 30, 2006 compared to Sept. 30, 2005:

Other revenues in the nine months ended Sept. 30, 2006 were $6.4 million lower than in the nine months ended Sept. 30, 2005 primarily due to a $5.4 million change in current decoupling deferral, a $2.9 million change in the amortization of decoupling deferral balances and a $0.8 million change in the amortization of Coos Bay distribution system deferrals, partially offset by a $1.3 million change in interstate gas storage credits and a $1.7 million change in amortization expense related to deferrals for the South Mist pipeline extension (see Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms, in the 2005 Form 10-K for further discussion of regulatory revenue adjustments).

Cost of Gas Sold

Although natural gas commodity prices have increased significantly over the last few years, prices have begun to decline recently, allowing more opportunity to purchase lower-priced spot market gas. During the third quarter and the first nine months of 2006, the cost per therm of gas sold was

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33 percent and 28 percent higher, respectively, than in the comparable 2005 periods. The cost per therm of gas sold primarily includes current gas purchases, gas withdrawn from storage inventory and net gains and losses from financial commodity hedge contracts. Prior to the last heating season, we locked in gas prices for approximately 90 percent of our commodity purchases before the disruptions caused by hurricanes Katrina and Rita, thereby avoiding a significant amount of the run-up in gas prices last fall and winter. Our rate increases last fall were much lower than those in other regions of the country due to our significant hedge position, but gas prices overall were still higher than in prior years, which accounted for the higher cost per therm of gas sold this year as compared to last year.

We use a natural gas commodity-price hedge program under the terms of our Derivatives Policy to help manage our variable price risk on gas purchases. During the three months ended Sept. 30, 2006, we recorded a net loss from financial hedge contracts of $12.4 million, compared to a net gain of $20.5 million during the same period in 2005. During the nine months ended Sept. 30, 2006, we recorded a net loss of $5.4 million from hedge contracts compared a gain of $30.3 million during the same period in 2005. Because our financial hedge contracts are directly related to variable-price risks in physical supply contracts which are included in PGA deferrals and annual regulatory rate changes, the resulting gains and losses are included in cost of gas as an offset to the higher or lower actual physical gas purchase costs. For the most part, financial hedge contract gains and losses are factored into the annual PGA adjustment and have no material impact on net income.

Under our PGA tariff in Oregon, if the cost of gas purchased is higher or lower than the cost embedded in rates, net income is charged or credited for 33 percent of the difference and the remaining 67 percent is deferred for pass through to customers in future rates. Our gas purchases in the third quarter of 2006 were slightly lower than the costs embedded in rates, and our share of the lower costs increased margin by $0.2 million. For the third quarter of 2005, our gas costs were also lower than the gas costs embedded in rates, and our share of the lower costs increased margin by $0.2 million. In the first nine months of 2006, our share of gas cost savings contributed $3.7 million to margin, compared to net savings and a contribution to margin of $1.9 million in the comparable 2005 period. The net benefit to customers from these gas cost savings amounted to $0.3 million and $7.4 million for the three and nine months ended Sept. 30, 2006, respectively.

Based on our ongoing assessment of gas prices and market risks, we began moderating our hedge position earlier this year as compared to prior years. Typically, by the time we file for our annual PGA rate change, we have a high percentage of the next gas contract year s estimated gas purchase requirements hedged. However, this year we went into the PGA with a lower than normal but still significant percentage of gas purchases hedged based on market conditions and gas price outlook. As gas prices began to decline in late August and early September, we increased our hedge positions, adding both to our storage levels with spot gas purchases and to our fixed-price financial swap portfolio to lock in gas prices on forward purchases. Our current overall hedge position for the upcoming gas contract year is below where we have been hedged over the past few years, and this may subject us to greater purchased gas cost variability in the future as compared to previous years (see Part II, Item 1A., Risk Factors, below). Variations in gas costs are subject to our PGA mechanisms (see Results of Operations Rate Mechanisms, above).

Business Segments Other than Gas Distribution Operations

Interstate Gas Storage

Net income from our interstate gas storage business segment in the three and nine months ended Sept. 30, 2006 was $1.5 million and $4.8 million, respectively, after regulatory sharing and income taxes, or 5 cents and 17 cents per share, respectively. This compares to net income of $1.6 million, or 6 cents per share, and $3.3 million, or 12 cents per share, in the three and nine months ended Sept. 30, 2005, respectively. The increase in the nine month results was primarily due to interstate storage capacity added during mid-year 2005 and an increase in revenues from our asset optimization arrangement with an

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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. The total working gas capacity of the Mist underground gas storage facility has been revised from 13.9 Bcf to 14.0 Bcf to reflect reservoir performance and incremental growth in certain reservoir pools.

Third-party optimization is provided pursuant to a contract with an unaffiliated energy marketing company, which assists in the optimization of the value of our assets primarily through the use of commodity transactions. In Oregon, we retain 80 percent of the pre-tax income from interstate storage services and optimization activities when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income from such optimization when the capacity costs have been included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for crediting to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from interstate storage services and third-party optimization.

Other

The other business segment primarily consists of a wholly-owned subsidiary, Financial Corporation, as well as various other non-utility investments, including an investment in a leveraged aircraft lease (see Part II, Item 8., Note 2, Consolidated Subsidiary Operations and Segment Information, in the 2005 Form 10-K). Operating results for both the three months ended Sept. 30, 2006 and 2005 were net income of $0.2 million. For the nine months ended Sept. 30, 2006 and 2005 net income was $0.3 million and $0.7 million, respectively.

Our net investment balances in Financial Corporation at Sept. 30, 2006 and 2005 were $2.7 and $3.2 million, respectively. The $0.5 million decrease primarily reflects lower cash investments due to a cash dividend paid to NW Natural in the second quarter of 2006. Our net investment balance in the leveraged aircraft lease at Sept. 30, 2006 and 2005 was $7.2 million and $6.9 million, respectively, with the increase due to recognition of earned lease revenues.

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses in the third quarter of 2006 were $25.6 million, representing a $0.3 million, or 1 percent, decrease over the third quarter of 2005. The following summarizes the major factors that contributed to the decrease in operations and maintenance expense:

- a $0.3 million decrease in bad debt expense due to an improvement in delinquencies and bad debt recoveries;
- a $0.8 million decrease in repair costs and damage claims relating to our utility mains and services;
- offset, in part, by a $0.9 million increase in payroll-related expenses resulting from pay increases and higher benefit costs.

Operations and maintenance expenses in the first nine months of 2006 increased $1.6 million, or 2 percent, compared to the first nine months of 2005. The following summarizes the major factors that contributed to the increase in operations and maintenance expense:

- a $1.5 million increase in payroll-related expenses resulting from pay increases and higher benefit costs;
- a $0.6 million increase in bad debt expense related to increases in gross revenues and delinquencies resulting from higher natural gas prices;
- a $0.6 million increase in corporate development and planning expenses;

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a $0.6 million increase in stock option expense due to the required adoption of a new accounting rule related to share-based compensation (see Notes 2 and 4);

offset, in part, by a $0.7 million decrease in injury and property damage claims; and

an $0.8 million decrease in repair costs and damage claims relating to our utility mains and services.

General Taxes

General taxes, which are principally comprised of property taxes, payroll taxes and regulatory fees, decreased $0.3 million, or 5 percent, in the three months ended Sept. 30, 2006 over the same period in 2005, but increased $1.3 million, or 7 percent, in the nine months ended Sept. 30, 2006 over the same period in 2005. Property taxes increased $0.1 million, or 2 percent, and $0.7 million, or 6 percent, in the three- and nine-month periods ended Sept. 30, 2006, respectively, over the same periods in 2005, due to utility plant additions in 2006 and 2005. Regulatory fees increased $0.6 million in the nine months ended Sept. 30, 2006 over the same period in 2005, reflecting increased gross operating revenues, but these fees decreased by $0.4 million in the three months ended Sept. 30, 2006 over the same period in 2005 primarily due to timing differences between this year and last year.

Depreciation and Amortization

Depreciation and amortization expense increased by $0.7 million, or 5 percent, and $2.0 million, or 4 percent, in the three- and nine-month periods ended Sept. 30, 2006, respectively, compared to the same periods in 2005. The increased expense reflects ongoing capital expenditures for utility plant that were made primarily to meet continuing customer growth and to upgrade operating facilities.

Other Income and Expense Net

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

	Three Months Ended Sept. 30,		**Nine Months Ended Sept. 30,**	
Thousands	**2006**	**2005**	**2006**	**2005**
Other income (expense):				
Gains from Company-owned life insurance	$ 399	$ 436	$ 2,196	$ 1,410
Interest income	31	180	306	409
Other non-operating expense	(262)	(202)	(1,080)	(1,061)
Net interest on deferred regulatory accounts	(109)	99	(494)	123
Earnings from equity investments of Financial Corporation	255	37	314	139
Total other income	$ 314	$ 550	$ 1,242	$ 1,020

Other income and expense net was $0.2 million lower in the third quarter of 2006 compared to the same period in 2005, and $0.2 million higher in the nine months ended Sept. 30, 2006 compared to the same period in 2005. The increase in the nine-month period was due to realized life insurance benefits from company-owned policies and earnings from non-utility equity investments, which were partially offset by interest charges on net regulatory liability account balances, as compared to interest income on net regulatory asset balances last year, and lower interest income on a reduced level of temporary cash investments.

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Interest Charges Net of Amounts Capitalized

Interest charges net of amounts capitalized increased $0.5 million, or 6 percent, and $1.5 million, or 6 percent, in the three- and nine-month periods ended Sept. 30, 2006 and 2005, respectively, primarily due to higher balances of total debt outstanding and higher interest rates on short-term debt borrowing.

Income Taxes

The effective corporate income tax rate on income from operations was 35.9 percent for the nine-month period ended Sept. 30, 2006, compared to 35.7 percent for the nine-month period ended Sept. 30, 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 Sept. 30, 2006 and 2005 and at Dec. 31, 2005, including short-term debt, was as follows:

	Sept. 30,		Dec. 31,
	2006	**2005**	**2005**
Common stock equity	48.7%	48.7%	47.2%
Long-term debt	40.4%	44.5%	42.0%
Short-term debt, including current maturities of long-term debt	10.9%	6.8%	10.8%
Total	100.0%	100.0%	100.0%

The increase in the common stock equity percentage in September 2006 compared to December 2005 is primarily due to increased earnings and strong cash flows, which has reduced the need to issue debt to fund capital expenditures. 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.

The Board has approved a program for the repurchase of up to 2.6 million shares, or up to $85 million in value, of our common stock. Purchases under this program are made in the open market or through privately negotiated transactions. Since the program s inception in 2000, we have repurchased 812,700 shares of common stock at a total cost of $24.7 million, including 47,100 shares at a total cost of $1.6 million in the first nine months of 2006 (see Financing Activities, and Part II, Item 2., Unregistered Sales of Equity Securities and Use of Proceeds, below) . The Board also approved a 3 percent increase in the common stock dividend rate, from 34.5 cents to 35.5 cents per share, effective Nov. 15, 2006.

Liquidity and Capital Resources

At Sept. 30, 2006, we had $5.7 million of cash and cash equivalents compared to $3.4 million at Sept. 30, 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, which are available through Sept. 30, 2010 (see Lines of Credit, below, and Part II, Item 8., Note 6, in the 2005 Form 10-K). Proceeds from the issuance of long-term debt are used to finance capital expenditures and refinance maturing short-term or long-term debt.

Neither our Mortgage and Deed of Trust nor the indenture under which long-term debt is issued contain credit rating triggers or stock price provisions that require the acceleration of debt repayment. Also, there are no rating triggers or stock price provisions contained in contracts or other agreements with third parties, except for agreements with certain counterparties under our 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 (AMR) equipment. Besides this contract and other contracts entered into in the ordinary course of business, there were no material changes to our estimated future contractual obligations during the nine months ended Sept. 30, 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 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 $103.3 million in commercial paper notes outstanding at Sept. 30, 2006, compared to $72.5 million outstanding at Sept. 30, 2005 and $126.7 million outstanding at Dec. 31, 2005. Commercial paper balances are typically lower at the end of the third quarter compared to year-end because year-end working capital balances tend to include increases in customer receivables and gas inventories due to seasonality.

Lines of Credit

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

The bank lines require us to maintain an indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending

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commitments and to accelerate the maturity of any amounts outstanding. We were in compliance with this covenant at Sept. 30, 2006 and at Dec. 31, 2005, and with the equivalent covenant in the prior year s lines of credit at Sept. 30, 2005. We also expect to be in compliance with this debt covenant at the end of this year, after including the effect of adopting Statement of Financial Accounting Standards (SFAS) No. 158 for the recognition of underfunded pension and postretirement benefit obligations (see Note 2).

Credit Ratings

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

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

Both rating agencies have assigned NW Natural an investment grade rating. These credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Redemptions of Long-Term Debt

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

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, gas prices, deferred income taxes, changes in working capital requirements, regulatory deferrals and other cash and non-cash adjustments to operating results. The overall change in cash flow from operating activities for the nine months ended Sept. 30, 2006 compared to the same period in 2005 was an increase of $27.5 million, primarily due to a $20.0 million contribution to the qualified defined benefit pension plans in September 2005. The major factors contributing to the cash flow changes in the first nine months of 2006 compared to the first nine months of 2005 are as follows:

an increase in net income added $0.9 million to cash flow;

an increase in inventory balances reduced cash flow by $18.4 million, primarily reflecting a net increase in gas storage volumes and higher gas prices, compared to an inventory increase of $32.3 million during 2005;

no contributions to the qualified defined benefit pension plans in 2006 reflected a net increase in cash flow of $20.0 million compared to last year;

a decrease in accounts receivable and accrued unbilled revenue - net increased 2006 cash flow by $113.8 million, or $34.5 million greater than the $79.3 million in 2005, due to the collection of higher year-end balances, reflecting higher rates and colder weather;

a decrease in accounts payable reduced cash flow by $70.8 million in 2006 compared to a $20.8 million reduction in 2005, due to the payment of higher year-end balances, primarily reflecting higher gas invoice prices for December 2005 compared to December 2004;

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an increase in other adjustments, primarily related to a change in regulatory liabilities for decoupling, increased cash flow by $9.9 million in 2006, compared to a $1.9 million reduction of cash flow in 2005; and

a decrease in other current and accrued liabilities reduced cash flow by $5.9 million partially related to decreased liabilities for industrial customer settlement charges at year-end 2005 and customer deposits.

We have lease and purchase commitments relating to 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).

Investing Activities

Cash requirements for investing activities in the first nine months of 2006 totaled $64.4 million, down from $66.5 million in the same period of 2005. Cash requirements for the acquisition and construction of utility plant totaled $67.4 million, up from $65.2 million in the first nine months of 2005. The increase in utility plant spending in 2006 was primarily related to the AMR project and pipeline integrity costs in 2006 (see Contractual Obligations, above), which were partially offset by lower capital spending under our bare steel replacement program.

Investments in non-utility property during the first nine months of 2006 totaled $0.8 million, down from $5.5 million during the first nine months of 2005 due primarily to amounts related to the capital improvements to our interstate gas storage facilities in 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.

In September 2006, we announced that we are evaluating a potential pipeline project that would connect GTN s interstate transmission line to our gas distribution system. If the project is determined to be viable, we would form a partnership with GTN to build and own the pipeline, which would require a material investment. However, the project s status will not be confirmed until 2007, and no material contractual obligations have been committed as of Sept. 30, 2006. If it is determined to be viable, the project could potentially be operating by 2011 (see Strategic Opportunities, above).

Financing Activities

Cash used in financing activities in the first nine months of 2006 totaled $59.2 million, up from $30.1 million in the same period of 2005. The primary factors contributing to the $29.1 million increase were differences in debt financings and common stock repurchases. Common stock repurchases in 2006 totaled $1.6 million compared to $13.8 million in 2005. Debt financing activity consisted of a net $31.4 million of short-term and long-term debt redemptions in 2006, compared to $45.5 million in 2005, and $50.0 million of new long-term debt issuance proceeds in 2005, compared to no new financing in 2006.

Under our common stock repurchase program, we have purchased 47,100 shares at a total cost of $1.6 million in the first nine months of 2006, compared to 377,900 shares at a total cost of $13.8 million in the first nine months of 2005.

Pension Funding Status

In September 2006, the Financial Accounting Standards Board issued SFAS No. 158 related to accounting for pension and other postretirement benefits (see Note 2, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans). SFAS No. 158 is effective for years ending after Dec. 15, 2006 and will require us to recognize the overfunded or underfunded status of our defined benefit postretirement plans as an asset or liability on the balance sheet. The issues surrounding the measurement of postretirement benefit obligations are complex, including factors relating to expectations about the future. Under previous accounting rules, if the fair value of plan assets exceeded the accumulated benefit obligation (ABO), which is defined as the value of employee benefits accrued for services rendered based on current and past compensation levels, then a liability was not required to be recognized on the balance sheet. However, under new accounting rules the pension benefit obligation is required to be recognized based on the projected benefit obligation, which is defined as the value of employee benefits accrued for service rendered based on future wage increases, including an assumption that the plan will continue in effect. We are in the process of evaluating the obligation amount that will be required to be recognized as a liability on the balance sheet at the end of this year. Based on the funded status of our benefit obligations at the end of last year, we would increase pension and postretirement liabilities by approximately $41 million.

It is our policy to continue making contributions to the qualified pension plans, as needed, based on tax regulations and funding requirements under federal law, including funding the amounts required by the Employee Retirement Income Security Act of 1974. In addition, it is our intent to contribute sufficient amounts as are needed on an actuarial basis to maintain funding targets, which generally provide for the fair value of plan assets to be equal to or greater than the plan s ABO, and to provide for the timely payment of future benefits under these plans.

Contingencies

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of loss is reasonably estimable in accordance with SFAS No. 5, Accounting for Contingencies. 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 9). 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. In accordance with SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, we have recorded a regulatory asset for the amount expected to be recovered. We intend to pursue recovery of these environmental costs from our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. At Sept. 30, 2006, a cumulative $22.8 million in environmental cost deferrals has been recorded as a regulatory asset, consisting of $17.1 million of costs paid to-date and $5.7 million of accrued estimated future environmental expenditures. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. See Note 9.

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Ratios of Earnings to Fixed Charges

For the nine months and 12 months ended Sept. 30, 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 2.77, 3.32 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.

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 laws and policies related to recovery of taxes in rates and changes in and compliance with environmental and safety laws, and regulations, policies, orders and laws with respect to the maintenance of pipeline integrity;

- 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;

- 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;

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- 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;
- our ability to achieve the cost savings expected from operations model design changes;
- 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.

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Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, weather risk, and interest rate risk (see Item 7A. in the 2005 Form 10-K and below, and see Note 6, above, and Part II, Item 1A., Risk Factors, below).

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. 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.

Based on our ongoing assessment of gas prices and market risks, we began moderating our hedge position earlier this year as compared to prior years. Typically, by the time we file for our annual PGA rate change, we have a high percentage of the next gas contract year s estimated gas purchase requirements hedged. However, this year we went into the PGA with a lower than normal but still significant percentage of gas purchases hedged based on market conditions and gas price outlook. As gas prices began to decline in late August and early September, we increased our hedge positions, adding both to our storage levels with spot gas purchases and to our fixed-price financial swap portfolio to lock in gas prices on forward purchases. Our current overall hedge position for the upcoming gas contract year is below where we have been hedged over the past few years, and this may subject us to greater purchased gas cost variability in the future as compared to previous years (see Part II, Item 1A., Risk Factors, below). Variations in gas costs are subject to our PGA mechanisms (see Results of Operations Rate Mechanisms, 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 $29.1 million at Sept. 30, 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 Position by Credit Rating

	Unrealized Fair Value Gain (Loss)		
	Sept. 30,		Dec. 31,
Thousands	**2006**	**2005**	**2005**
AA/Aa	(29,122)	317,032	172,315
BBB/Baa		23,481	3,346
Total	$ (29,122)	$ 340,513	$ 175,661

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Credit exposure to customers. Rate increases effective Nov. 1, 2006 are expected to increase our credit exposure to customers. We monitor and manage the credit exposure of our customers through the consistent application of credit policies and procedures which are designed to reduce credit risk. These policies and procedures include an ongoing review of credit risks, including changes in market conditions and customers payment patterns. Changes in credit risk may require us to obtain additional assurance, such as deposits, letters of credit, guarantees or prepayments to reduce our credit exposure.

Item 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As of Sept. 30, 2006, the principal executive officer and principal financial officer of NW Natural have evaluated the effectiveness of the design and operation of NW Natural 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 NW Natural have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by NW Natural and included in NW Natural s reports filed with or furnished to the Securities and Exchange Commission under the Exchange Act is accumulated and communicated to NW Natural s management as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in NW Natural s internal control over financial reporting that occurred during NW Natural s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, NW Natural s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Litigation

For a discussion of certain pending legal proceedings, see Note 9, above.

Item 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors, in our Annual Report on Form 10-K for the year ended Dec. 31, 2005 and the updates to certain of those risk factors described below, which could materially affect our business, financial condition or results of operations. The risks described in our Annual Report on Form 10-K, as updated below, are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our financial condition, results of operations or cash flows.

Higher natural gas commodity prices and fluctuations in the price of gas may adversely affect our earnings.

In recent years, natural gas commodity prices have increased dramatically due to growing demand, especially for power generation, and stagnant North American gas production. In Oregon, the utility has a Purchased Gas Adjustment (PGA) tariff which provides for annual revisions in rates resulting from changes in the cost of purchased gas. The PGA tariff provides that 33 percent of any difference between the actual purchased gas costs and the actual recoveries of gas costs in revenues will be recognized as current income or expense. Accordingly, higher gas costs than those assumed in setting rates can adversely affect our results of operations.

Notwithstanding our current rate structure, higher gas costs could result in increased pressure on the Public Utility Commission of Oregon (OPUC) or the Washington Utilities and Transportation Commission (WUTC) to seek other means to reduce rates to a level that could adversely affect our financial condition, results of operations or cash flows.

Our results of operations may be negatively affected by warmer than average weather.

A large portion of the utility s margin is derived from sales to space heating residential and commercial customers during each winter heating season. Current rates are based on an assumption of average weather. In Oregon, the effects of warmer or colder weather on utility margin are reduced through the operation of our weather normalization mechanism and conservation tariff. From June 1 through November 30, the operation of the conservation tariff largely offsets the risk of warmer weather and declining consumption. From December 1 through May 15, the weather normalization mechanism adjusts for the effects of weather in Oregon. However, 10 percent of eligible customers elected not to be covered by the mechanism. Also, approximately 10 percent of our residential and commercial customers are in Washington where we do not have a weather normalization mechanism or conservation tariff. As a result, we are not fully protected against warmer than average weather, which may have an adverse affect on our financial condition, results of operations or cash flows.

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

The following table provides information about purchases by us during the quarter ended Sept. 30, 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[2]
Balance forward			812,700	$ 60,260,697
07/01/06 - 07/31/06	2,109	$ 36.30		
08/01/06 - 08/31/06	23,859	$ 37.99		
09/01/06 - 09/30/06	1,864	$ 38.96		
Total	27,832	$ 37.93	812,700	$ 60,260,697

(1) During the quarter ended Sept. 30, 2006, 26,934 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan (DSPP). In addition, 898 shares of our common stock were purchased in the open market during the quarter under equity-based programs. During the three months ended Sept. 30, 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. During the three months ended Sept. 30, 2006, no shares of our common stock were purchased pursuant to this program. Since the program s inception, we have repurchased 812,700 shares of common stock at a total cost of $24.7 million. In April 2006, the Board extended the program through May 31, 2007 and increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million.

On Sept. 29, 2006, we entered into a Stock Purchase Plan Engagement Agreement with our broker in order to establish a trading plan for our repurchase program that qualifies for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Securities Exchange Act of 1934, as amended.

Item 6. EXHIBITS

See Exhibit Index attached hereto.

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SIGNATURE

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

NORTHWEST NATURAL GAS COMPANY
(Registrant)

Dated: Nov. 2, 2006

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

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX

To

Quarterly Report on Form 10-Q

For Quarter Ended

September 30, 2006

Document	Exhibit Number
Executive Deferred Compensation Plan, 2007 Restatement	10.1
Deferred Compensation Plan for Directors and Executives, Restated as of January 1, 2007	10.2
Directors Deferred Compensation Plan, Restated as of January 1, 2007	10.3
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