NORTHWEST NATURAL GAS CO
Form 10-Q
November 07, 2013

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, 2013

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 number 1-15973

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

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

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)
Registrant’s telephone number, including area code: (503) 226-4211

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [X] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer [X]	Accelerated Filer [ ]
Non-accelerated Filer [ ] (Do not check if a Smaller Reporting Company)	Smaller Reporting Company [ ]

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

At October 25, 2013, 27,002,556 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY
For the Quarterly Period Ended September 30, 2013

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FORWARD-LOOKING STATEMENTS

This report contains “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as “anticipates,” “intends,” “plans,” “seeks,” “believes,” “estimates,” “expects” and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following:

- plans;
- objectives;
- goals;
- strategies;
- assumptions and estimates;
- future events or performance;
- trends;
- timing and cyclicality;
- earnings and dividends;
- growth;
- customer rates;
- commodity costs;
- gas reserves;
- operational performance and costs;
- efficacy of derivatives and hedges;
- liquidity and financial positions;
- project development and expansion;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- rate recovery and refunds;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- potential claims, outcomes and effects of litigation, regulatory actions, and other administrative matters;
- projected obligations under retirement plans;
- availability, adequacy, and shift in mix of gas supplies;
- approval and adequacy of regulatory deferrals; and
- environmental, regulatory, litigation and insurance costs and recoveries.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks, and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed in our 2012 Annual Report on Form 10-K, Part I, Item 1A. “Risk Factors” and Part II, Item 7. and Item 7A., “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures about Market Risk,” and in Part I, Items 2 and 3, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative

Disclosures About Market Risk," and Part II, Item 1A, "Risk Factors," herein.

Any forward-looking statement made by us in this report speaks only as of the date on which it is made. Factors or events that could cause our actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

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ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per share data	2013	2012	2013	2012
Operating revenues	$88,195	$87,501	$497,770	$501,131
Operating expenses:				
Cost of gas	33,655	37,570	235,156	241,823
Operations and maintenance	32,636	28,973	99,610	95,543
General taxes	6,954	7,473	23,028	23,726
Depreciation and amortization	18,737	18,281	56,474	54,330
Total operating expenses	91,982	92,297	414,268	415,422
Income (loss) from operations	(3,787)	(4,796)	83,502	85,709
Other income and expense, net	1,300	1,180	3,270	2,272
Interest expense, net	11,347	10,508	33,543	32,163
Income (loss) before income taxes	(13,834)	(14,124)	53,229	55,818
Income tax expense (benefit)	(5,601)	(3,245)	21,697	25,186
Net income (loss)	(8,233)	(10,879)	31,532	30,632
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $152 and $108 for the three months and $454 and $325 for the nine months ended September 30, 2013 and 2012, respectively	232	167	697	499
Comprehensive income (loss)	$(8,001)	$(10,712)	$32,229	$31,131
Average common shares outstanding:				
Basic	26,987	26,847	26,962	26,813
Diluted	26,987	26,847	27,013	26,902
Earnings (loss) per share of common stock:				
Basic	$(0.31)	$(0.41)	$1.17	$1.14
Diluted	(0.31)	(0.41)	1.17	1.14
Dividends declared per share of common stock	0.455	0.445	1.365	1.335

See Notes to Unaudited Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	September 30, 2013	September 30, 2012	December 31, 2012
Assets:			
Current assets:			
Cash and cash equivalents	$16,105	$5,718	$8,923
Accounts receivable	29,821	23,382	61,229
Allowance for uncollectible accounts	(802)	(1,985)	(2,518)
Accrued unbilled revenue	16,493	11,184	56,955
Regulatory assets	26,293	53,891	52,448
Derivative instruments	1,452	6,771	1,950
Inventories	75,419	73,188	67,602
Gas reserves	18,083	13,140	14,966
Income taxes receivable	909	1,787	2,552
Other current assets	11,936	10,825	19,592
Total current assets	195,709	197,901	283,699
Non-current assets:			
Property, plant, and equipment	2,865,860	2,755,729	2,786,008
Less: Accumulated depreciation	846,346	798,510	812,396
Total property, plant, and equipment, net	2,019,514	1,957,219	1,973,612
Gas reserves	115,218	75,925	84,693
Regulatory assets	387,676	362,472	382,255
Derivative instruments	1,682	5,608	3,639
Other investments	67,548	67,333	67,667
Restricted cash	4,000	4,000	4,000
Other non-current assets	14,566	14,690	13,555
Total non-current assets	2,610,204	2,487,247	2,529,421
Total assets	$2,805,913	$2,685,148	$2,813,120

See Notes to Unaudited Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	September 30, 2013	September 30, 2012	December 31, 2012
Liabilities and equity:			
Current liabilities:			
Short-term debt	$141,300	$175,800	$190,250
Current maturities of long-term debt	60,000	—	—
Accounts payable	67,652	61,327	85,613
Taxes accrued	11,302	10,269	9,588
Interest accrued	11,143	10,593	5,953
Regulatory liabilities	16,506	24,810	20,792
Derivative instruments	8,275	17,156	10,796
Other current liabilities	26,289	45,425	45,444
Total current liabilities	342,467	345,380	368,436
Long-term debt	681,700	641,700	691,700
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	463,566	428,821	444,377
Regulatory liabilities	298,220	288,097	288,113
Pension and other postretirement benefit liabilities	210,943	182,069	215,792
Derivative instruments	1,404	615	578
Other non-current liabilities	77,322	84,063	74,497
Total deferred credits and other non-current liabilities	1,051,455	983,665	1,023,357
Commitments and contingencies (see Note 13)	—	—	—
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 27,001, 26,866, and 26,917 at September 30, 2013 and 2012 and December 31, 2012, respectively	361,789	355,276	356,571
Retained earnings	377,096	366,428	382,347
Accumulated other comprehensive loss	(8,594)	(7,301)	(9,291)
Total equity	730,291	714,403	729,627
Total liabilities and equity	$2,805,913	$2,685,148	$2,813,120

See Notes to Unaudited Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30,	
In thousands	2013	2012
Operating activities:		
Net income	$31,532	$30,632
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	56,474	54,330
Deferred tax liabilities	22,003	23,965
Non-cash expenses related to qualified defined benefit pension plans	4,256	4,334
Contributions to qualified defined benefit pension plans	(8,900)	(23,500)
Deferred environmental expenditures, net of recoveries	(10,805)	(6,500)
Other	6,016	2,612
Changes in assets and liabilities:		
Receivables	70,154	106,620
Inventories	(7,817)	1,175
Taxes accrued	3,357	4,780
Accounts payable	(19,860)	(24,888)
Interest accrued	5,190	4,736
Deferred gas costs	(4,159)	(15,406)
Other, net	9,961	15,172
Cash provided by operating activities	157,402	178,062
Investing activities:		
Capital expenditures	(86,287)	(100,880)
Utility gas reserves	(41,777)	(41,775)
Proceeds from sale of assets	6,580	—
Other	2,116	107
Cash used in investing activities	(119,368)	(142,548)
Financing activities:		
Common stock issued, net	3,754	4,858
Long-term debt issued	50,000	—
Long-term debt retired	—	(40,000)
Change in short-term debt	(48,950)	34,200
Cash dividend payments on common stock	(36,783)	(35,779)
Other	1,127	1,092
Cash used in financing activities	(30,852)	(35,629)
Increase (decrease) in cash and cash equivalents	7,182	(115)
Cash and cash equivalents, beginning of period	8,923	5,833
Cash and cash equivalents, end of period	$16,105	$5,718
Supplemental disclosure of cash flow information:		
Interest paid	$28,353	$27,427
Income taxes paid	570	2,333

See Notes to Unaudited Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidation of Northwest Natural Gas Company (NW Natural or the Company) and all companies that we directly or indirectly control, either through majority ownership or otherwise. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), and NW Natural Gas Reserves, LLC (NWN Gas Reserves). Investments in corporate joint ventures and partnerships that we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method or the cost method, which includes NWN Energy’s investment in Palomar Gas Holdings, LLC (PGH) and NNG Financial's investment in Kelso-Beaver (KB) Pipeline. NW Natural and its affiliated companies are collectively referred to herein as NW Natural. The consolidated unaudited financial statements are presented after elimination of all significant intercompany balances and transactions, except for amounts required to be included under regulatory accounting standards to reflect the effect of such regulation. In this report, the term “utility” is used to describe our regulated gas distribution business, and the term “non-utility” is used to describe our gas storage business and other non-utility investments and business activities.

During the first quarter of 2013, we identified an error in the rate used to calculate interest on regulatory assets. We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the annual and interim periods for 2013, if corrected in 2013. As a result, in accordance with accounting standards, we have revised our prior period financial statements as shown in Note 14 to correct this error.

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

Information presented in these interim unaudited consolidated financial statements is unaudited, but includes all material adjustments that management considers necessary for a fair statement of the results for each period reported including normal recurring accruals. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2012 Annual Report on Form 10-K (2012 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.

2. SIGNIFICANT ACCOUNTING POLICIES

Our significant accounting policies are described in Note 2 of the 2012 Form 10-K. There were no material changes to those accounting policies during the nine months ended September 30, 2013. The following are current updates to certain critical accounting policy estimates and accounting standards in general.

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Regulatory Accounting

In applying regulatory accounting in accordance with generally accepted accounting principles in the United States of America (GAAP), we capitalize or defer certain costs and revenues as regulatory assets and liabilities. The amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets		
	September 30,		December 31,
In thousands	2013	2012	2012
Current:			
Unrealized loss on derivatives[1]	$8,275	$17,156	$10,796
Other[2]	18,018	36,735	41,652
Total current	$26,293	$53,891	$52,448
Non-current:			
Unrealized loss on derivatives[1]	$1,404	$615	$578
Pension balancing[3]	22,976	12,909	14,727
Income tax asset	53,065	58,437	55,879
Pension and other postretirement benefit liabilities[3]	187,000	158,894	182,688
Environmental costs[4]	118,029	123,178	121,144
Other[2]	5,202	8,439	7,239
Total non-current	$387,676	$362,472	$382,255

	Regulatory Liabilities		
	September 30,		December 31,
In thousands	2013	2012	2012
Current:			
Gas costs	$3,096	$10,069	$9,100
Unrealized gain on derivatives[1]	1,386	6,771	1,950
Other[2]	12,024	7,970	9,742
Total current	$16,506	$24,810	$20,792
Non-current:			
Gas costs	$11	$596	$—
Unrealized gain on derivatives[1]	1,682	5,608	3,639
Accrued asset removal costs	293,005	278,897	281,213
Other[2]	3,522	2,996	3,261
Total non-current	$298,220	$288,097	$288,113

(1) Unrealized gains or losses on derivatives are non-cash items and, therefore, do not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment (PGA) mechanism when realized at settlement.

(2) Other primarily consists of several deferrals and amortizations under other approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(3) Certain utility pension costs are approved for regulatory deferral, including amounts recorded to the pension balancing account, to mitigate the effects of higher and lower pension expenses. Pension costs that are deferred include an interest component when recognized in net periodic benefit costs. See Note 7.

(4) Environmental costs relate to specific sites approved for regulatory deferral by the Public Utility Commission of Oregon (OPUC) and Washington Utilities and Transportation Commission (WUTC). In Oregon, we earn a carrying charge on amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. In our 2012 Oregon general rate case, the OPUC authorized a Site Remediation and Recovery Mechanism (SRRM) that allows the Company to recover prudently incurred environmental costs, subject to an earnings test. For further information on environmental matters, see Note 13 and Note 15.

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New Accounting Standards

Recent Accounting Pronouncements

OBLIGATIONS RESULTING FROM JOINT AND SEVERAL LIABILITY ARRANGEMENTS. In February 2013, the Financial Accounting Standards Board (FASB) issued guidance regarding the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. Under the new guidance, an entity is required to measure fixed obligations as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors plus any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, an entity must disclose the nature and amount of the obligation as well as other information about the obligations. The guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. We are currently assessing the impact, if any, of this guidance on our financial position, results of operations, or disclosures.

PRESENTATION OF UNRECOGNIZED TAX BENEFIT. In July 2013, the FASB issued guidance that requires an unrecognized tax benefit, or a portion of an unrecognized tax benefit, be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except under certain circumstances as outlined in the standard. The new guidance is effective for annual and interim periods within those annual periods, beginning after December 15, 2013, with early adoption permitted. This guidance is not expected to have an impact on our financial position, results of operations, and disclosures.

Subsequent Events

See Note 15 for information regarding the environmental settlement we filed with the OPUC and the regulatory treatment of our Gasco water treatment station.

3. EARNINGS PER SHARE

Basic earnings per share are computed using net income and the weighted-average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except it uses the weighted-average number of common shares outstanding plus the effects of the assumed exercise of stock options, and payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented. Diluted earnings per share are calculated as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands, except per share data	2013	2012	2013	2012
Net income (loss)	$(8,233)	$(10,879)	$31,532	$30,632
Average common shares outstanding - basic	26,987	26,847	26,962	26,813
Additional shares for stock-based compensation plans outstanding	—	—	51	89
Average common shares outstanding - diluted	26,987	26,847	27,013	26,902
Earnings (loss) per share of common stock - basic	$(0.31)	$(0.41)	$1.17	$1.14
Earnings (loss) per share of common stock - diluted	$(0.31)	$(0.41)	$1.17	$1.14
Additional information:				
Anti-dilutive shares excluded from net income per diluted common share calculation	80	107	26	—

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4. SEGMENT INFORMATION

We operate in two primary reportable business segments, local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as “other.” We refer to our local gas distribution business as the “utility,” and our “gas storage” and “other” business segments as “non-utility.” Our utility segment also includes NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Our “other” segment includes NNG Financial and NWN Energy's equity investment in PGH, which is pursuing development of a cross-Cascades pipeline project. See Note 4 in our 2012 Form 10-K for further discussion of our segments.

The following table presents summary financial information concerning the reportable segments. Inter-segment transactions are insignificant:

	Three Months Ended September 30,			
In thousands	Utility	Gas Storage	Other	Total
2013				
Operating revenues	$80,705	$7,434	$56	$88,195
Depreciation and amortization	17,118	1,619	—	18,737
Income (loss) from operations	(7,293)	3,556	(50)	(3,787)
Net income (loss)	(9,605)	1,407	(35)	(8,233)
Capital expenditures	30,805	427	—	31,232
2012				
Operating revenues	$79,901	$7,544	$56	$87,501
Depreciation and amortization	16,661	1,620	—	18,281
Income (loss) from operations	(8,439)	3,624	19	(4,796)
Net income (loss)	(12,174)	1,255	40	(10,879)
Capital expenditures	38,577	751	—	39,328

	Nine Months Ended September 30,			
In thousands	Utility	Gas Storage	Other	Total
2013				
Operating revenues	$474,307	$23,295	$168	$497,770
Depreciation and amortization	51,617	4,857	—	56,474
Income (loss) from operations	72,372	11,138	(8)	83,502
Net income (loss)	27,083	4,495	(46)	31,532
Capital expenditures	85,327	960	—	86,287
Total assets at September 30, 2013	2,502,688	287,317	15,908	2,805,913
2012				
Operating revenues	$478,744	$22,219	$168	$501,131
Depreciation and amortization	49,477	4,853	—	54,330
Income from operations	76,072	9,567	70	85,709
Net income	27,424	3,185	23	30,632
Capital expenditures	99,019	1,861	—	100,880
Total assets at September 30, 2012	2,381,659	287,687	15,802	2,685,148
Total assets at December 31, 2012	$2,505,655	$291,568	$15,897	$2,813,120

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Utility Margin

Utility margin is a financial measure consisting of utility operating revenues less revenue taxes and the associated cost of gas. Cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. By netting costs of gas from utility operating revenues, utility margin provides a key metric used by our chief operating decision maker in assessing the performance of the utility segment. The following table presents additional segment information concerning utility margin. The gas storage and other segments emphasize growth in operating revenues and net income as opposed to margin because these segments do not incur commodity cost of sales like the utility and, therefore, use operating revenues and net income to assess performance.

	Three Months Ended September 30,		Nine Months Ended September 30,	
In thousands	2013	2012	2013	2012
Utility margin calculation:				
Utility operating revenues	$80,705	$79,901	$474,307	$478,744
Less: Utility cost of gas	33,655	37,570	235,156	241,823
Utility margin	$47,050	$42,331	$239,151	$236,921

5. STOCK-BASED COMPENSATION

Our stock-based compensation plans include a Long-Term Incentive Plan (LTIP) under which various types of equity awards may be granted, an Employee Stock Purchase Plan, and a Restated Stock Option Plan (Restated SOP). These plans are designed to promote stock ownership in NW Natural by employees and officers. For additional information on our stock-based compensation plans, see Note 6 in the 2012 Form 10-K and updates provided below.

Long-Term Incentive Plan

Performance-Based Stock Awards

LTIP performance shares incorporate market, performance, and service-based factors. On February 27, 2013, 37,300 performance-based shares were granted under the LTIP based on target-level awards and a weighted-average grant date fair value of $38.96 per share. Fair value was estimated as of the date of grant using a Monte-Carlo option pricing model based on the following assumptions:

Stock price on valuation date	$45.38	
Performance term (in years)	3.0	
Quarterly dividends paid per share	$0.455	
Expected dividend yield	3.9	%
Dividend discount factor	0.8943	

Performance-Based Restricted Stock Units (RSUs)

On February 27, 2013, 25,748 performance-based RSUs were granted under the LTIP with a grant date fair value of $45.38 per share. As of September 30, 2013, there was $1.7 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2017. The RSUs awarded include a performance-based threshold and a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU.

Restated Stock Option Plan

As of September 30, 2013, there was $0.2 million of unrecognized compensation cost from grants of stock options issued in prior years, which is expected to be recognized over a period extending through 2014. The Restated SOP was terminated for new option grants in 2012; however, options that had been granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP. No stock options were granted in the nine months ended September 30, 2013.

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6. DEBT

Short-Term Debt
At September 30, 2013, our short-term debt consisted of commercial paper notes payable with a maximum maturity of 75 days, an average maturity of 50 days, and an outstanding balance of $141.3 million. The carrying cost of our commercial paper approximates fair value using Level 2 inputs due to the short-term nature of the notes. See Note 2 in our 2012 Form 10-K for a description of the fair value hierarchy.

Long-Term Debt
At September 30, 2013, our utility's long-term debt, including current maturities, consisted of $701.7 million of first mortgage bonds (FMBs) with maturity dates ranging from 2014 through 2042, interest rates ranging from 3.176% to 9.05%, and a weighted-average coupon rate of 5.55%. On August 19, 2013, we issued $50 million of FMBs with a 3.542% coupon rate and a 10-year maturity. We did not redeem any FMBs during the nine months ended September 30, 2013.

At September 30, 2013, our gas storage segment's long-term debt consisted of $40 million of senior secured debt with a maturity date of November 30, 2016. This debt consists of $20 million of fixed rate debt with an interest rate of 7.75% and $20 million of variable interest rate debt, which currently has an interest rate of 7.00%. The debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural.

As our outstanding debt does not trade in active markets, we estimate the fair value of our outstanding long-term debt using interest rates of other companies' outstanding debt issuances that actively trade in public markets and have similar credit ratings, terms, and remaining maturities to our debt. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2 in our 2012 Form 10-K.

The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

	September 30,		December 31,
In thousands	2013	2012	2012
Carrying amount	$741,700	$641,700	$691,700
Estimated fair value	828,360	786,496	834,664

See Note 7 in our 2012 Form 10-K for more detail on our long-term debt.

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7. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

The following table provides the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans:

	Three Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2013	2012	2013	2012
Service cost	$2,341	$2,130	$178	$177
Interest cost	4,103	4,303	286	314
Expected return on plan assets	(4,678)	(4,637)	—	—
Amortization of net actuarial loss	4,421	3,844	169	103
Amortization of prior service costs	56	48	50	50
Amortization of transition obligations	—	—	—	103
Net periodic benefit cost	6,243	5,688	683	747
Amount allocated to construction	(1,910)	(1,676)	(226)	(252)
Amount deferred to regulatory balancing account[1]	(2,230)	(2,111)	—	—
Net amount charged to expense	$2,103	$1,901	$457	$495
	Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2013	2012	2013	2012
Service cost	$7,023	$6,390	$536	$531
Interest cost	12,310	12,911	858	943
Expected return on plan assets	(14,034)	(13,914)	—	—
Amortization of net actuarial loss	13,263	11,531	507	309
Amortization of prior service costs	167	146	148	148
Amortization of transition obligations	—	—	—	309
Net periodic benefit cost	18,729	17,064	2,049	2,240
Amount allocated to construction	(5,566)	(4,522)	(656)	(681)
Amount deferred to regulatory balancing account[1]	(6,850)	(6,273)	—	—
Net amount charged to expense	$6,313	$6,269	$1,393	$1,559

[1] Effective January 1, 2011, the OPUC approved the deferral of certain pension expenses above or below the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower net periodic benefit costs in future years. Deferred pension expense balances earn a carrying charge.

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The following table presents amounts recognized in accumulated other comprehensive loss (AOCL) and the changes in AOCL related to our non-qualified employee benefit plans:

In thousands	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Beginning balance	$(8,826)	$(9,291)
Amounts reclassified into AOCL	—	—
Amounts reclassified from AOCL:		
Amortization of prior service costs	(1)	(5)
Amortization of actuarial losses	385	1,156
Total reclassifications before tax	384	1,151
Tax expense	(152)	(454)
Total reclassifications for the period	232	697
Ending balance	$(8,594)	$(8,594)

Employer Contributions to Company-Sponsored Defined Benefit Pension Plan
In the nine months ended September 30, 2013, we made cash contributions totaling $8.9 million to our qualified defined benefit pension plan. In 2012, Congress passed the "Moving Ahead for Progress in the 21st Century Act" (MAP-21), which among other things, includes provisions that reduce the level of minimum required contributions in the near-term but generally increase contributions in the long-run as well as increase the operational costs of running a pension plan. We expect to make approximately $3 million in additional pension contributions during 2013.

Multiemployer Pension Plan
In addition to the Company-sponsored defined benefit pension plan referred to above, we contribute to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan) in accordance with our collective bargaining agreement. The employer identification number of the plan is 94-6076144. The cost of this plan, and corresponding future liabilities, are in addition to pension expense presented in the table above. Our contributions to the Western States Plan amounted to $0.3 million for both the nine months ended September 30, 2013 and 2012. Under the terms of our current collective bargaining agreement, we can withdraw from the Western States Plan at any time. However, if the plan is underfunded at the time we withdraw, we would be assessed a withdrawal liability. In accordance with accounting rules for multiemployer plans, we have not recognized these potential withdrawal liabilities on the balance sheet. Currently, we have made no decision to withdraw from the plan. We continue to monitor the financial condition of the plan and consider options with respect to this plan.

Defined Contribution Plan
The Retirement K Savings Plan provided to our employees is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Our contributions to this plan totaled $2.3 million and $1.7 million for the nine months ended September 30, 2013 and 2012, respectively.

See Note 8 in the 2012 Form 10-K for more information about these retirement and other postretirement benefit plans.

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8. INCOME TAX

The effective income tax rate varied from the combined federal and state statutory tax rates due to the following:

	Nine Months Ended September 30,	
	2013	2012
Federal statutory tax rate	35.0 %	35.0 %
Increase (decrease):		
Current state income tax, net of federal tax benefit	4.6	4.5
Amortization of investment and energy tax credits	(0.3)	(0.3)
Differences required to be flowed-through by regulatory commissions	2.2	1.4
Gains on company and trust-owned life insurance	(1.3)	(1.2)
One-time state tax adjustment, net of federal benefit	—	4.8
Other, net	0.6	0.9
Effective income tax rate	40.8 %	45.1 %

The decrease in the effective income tax rate for the nine months ended September 30, 2013 compared to the same period in 2012 was primarily due to a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance. See Note 9 in the 2012 Form 10-K for more detail on income taxes and effective tax rates.

9. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of our property, plant, and equipment and related accumulated depreciation:

	September 30,		December 31,
In thousands	2013	2012	2012
Utility plant in service	$2,482,034	$2,399,600	$2,435,886
Utility construction work in progress	80,325	53,017	46,831
Less: Accumulated depreciation	818,644	776,812	789,201
Utility plant, net	1,743,715	1,675,805	1,693,516
Non-utility plant in service	296,022	296,486	296,781
Non-utility construction work in progress	7,479	6,626	6,510
Less: Accumulated depreciation	27,702	21,698	23,195
Non-utility plant, net	275,799	281,414	280,096
Total property, plant, and equipment	$2,019,514	$1,957,219	$1,973,612

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10. GAS RESERVES

We have agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop physical gas reserves. These agreements are intended to provide long-term gas price protection for our utility customers rather than serving as a source of gas supply. Encana began drilling in 2011 under these agreements, and gas which is currently being produced from our working interests in these gas fields is sold by Encana at then prevailing market prices, with revenues from such sales, net of associated production costs, credited to our cost of gas. The cost of gas, including a carrying cost for the net rate base investment, is part of our annual Oregon PGA filing, which allows us to recover our costs through customer rates in a manner previously approved by the OPUC. This transaction acted to hedge the cost of gas for approximately 6% and 4% of our gas supplies for the nine months ended September 30, 2013 and 2012, respectively. Our utility gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. The following table outlines our net investment in gas reserves:

	September 30,		December 31,
In thousands	2013	2012	2012
Gas reserves, current	$18,083	$13,140	$14,966
Gas reserves, non-current	130,836	81,692	92,179
Less: Accumulated amortization	15,618	5,767	7,486
Total gas reserves	133,301	89,065	99,659
Less: Deferred tax liabilities on gas reserves	40,553	23,940	28,329
Net investment in gas reserves	$92,748	$65,125	$71,330

11. INVESTMENTS

Equity Method Investments

Palomar Gas Transmission, LLC (Palomar), a wholly-owned subsidiary of PGH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH is owned 50% by NWN Energy, a wholly-owned subsidiary of NW Natural, and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. PGH is a development stage VIE and our investment in Palomar is reported under equity method accounting based on the determination that we are not the primary beneficiary of PGH's activities, as defined by the authoritative guidance related to consolidations, due to the fact that we have only a 50% share and there are no stipulations that allow us a disproportionate influence over the entity. Our investment in PGH and Palomar are included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner. Our investment balance in PGH was $13.4 million at September 30, 2013. See Note 12 in our 2012 Form 10-K for more detail.

Other Investments

Other investments include financial investments in life insurance policies, which are accounted for at fair value. See Note 12 in the 2012 Form 10-K for more detail on other investments.

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12. DERIVATIVE INSTRUMENTS

We enter into swap, option, and combinations of option contracts for the purpose of hedging our utility's natural gas purchases. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange transactions related to purchases of natural gas transportation from Canadian suppliers.

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to these physical gas supply contracts as well as to hedge spot purchases of natural gas. The following table presents the absolute notional amounts related to open positions on financial derivative instruments:

In thousands	September 30, 2013	2012	December 31, 2012
Open position absolute notional amount:			
Natural gas volumes (therms)	527,700	460,470	395,820
Foreign exchange	$13,862	$13,775	$13,231

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years and prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate is set for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for either an 80% or 90% deferral of any gains and losses as regulatory assets or liabilities, with the remaining 10% or 20% recognized in current income. In general, our commodity hedging for the current gas year is completed prior to the start of the upcoming gas year, and hedge prices are included in the Company's WACOG in the PGA filing. We reached our target hedge percentage of approximately 75% for the upcoming gas year in the third quarter, and these hedges were included in the PGA filing and qualified for regulatory deferral.

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. We also enter into exchange contracts related to the optimization of our gas portfolio, which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement.

	Three Months Ended			
	September 30, 2013		September 30, 2012	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Cost of sales increase	$2,422	$—	$22,558	$—
Other comprehensive income	—	502	—	273
Less:				
Amounts deferred to regulatory accounts	(2,433)	(502)	(22,558)	(273)
Total loss in pre-tax earnings	$(11)	$—	$—	$—

	Nine Months Ended			
	September 30, 2013		September 30, 2012	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Cost of sales decrease	$(6,534)	$—	$(5,556)	$—
Other comprehensive income (loss)	—	(11)	—	162
Less:				
Amounts deferred to regulatory accounts	6,599	11	5,556	(162)

Total gain in pre-tax earnings	$65	$—	$—	$—

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No collateral was posted with or by our counterparties as of September 30, 2013 or 2012. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and portfolio diversification, we have not been subject to collateral calls in 2012 or 2013. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current financial derivative contracts outstanding, which reflect unrealized losses of $6.4 million at September 30, 2013, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

	Credit Rating Downgrade Scenarios				
In thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$—	$—	$—	$—	$4,081
Without Adequate Assurance Calls	—	—	—	—	4,212

Our derivative financial instruments are subject to master netting arrangements; however, they are presented on a gross basis on the face of our statement of financial position. The Company and its counterparties have the ability to set-off their obligations to each other under specified circumstances. Generally set-off of any early termination amount payable to one party by the other party, in circumstances where there is a defaulting party or where there is one affected party in the case where either a credit event upon merger has occurred, the occurrence of an event of default or any other termination event, will, at the option of the non-defaulting party be reduced by or set-off against any other amounts payable. If netted by counterparty, our derivative position would result in an asset of $0.2 million and a liability of $6.7 million as of September 30, 2013. As of September 30, 2012, our derivative position would also result in an asset of $0.2 million and a liability of $5.6 million.

In the three and nine months ended September 30, 2013, we realized net losses of $2.3 million and $6.3 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas, compared to net losses of $12.7 million and $63.3 million, respectively, for the three and nine months ended September 30, 2012. The currency exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts.

We are exposed to derivative credit and liquidity risk primarily through securing fixed price natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases made on behalf of customers. See Note 13 in our 2012 Form 10-K for more information on our derivative instruments.

Fair Value

In accordance with fair value accounting, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation techniques include natural gas futures, volatility, credit default swap spreads and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at September 30, 2013. As of September 30, 2013 and 2012 and December 31, 2012, the fair value was a liability of $6.5 million, $5.4 million, and $5.8 million, respectively, using significant other observable, or Level 2, inputs. We have used no Level 3 inputs in our derivative valuations. We did not have any transfers between Level 1 or Level 2 during the nine months ended September 30, 2013 and 2012.

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13. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation 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. Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated. Unless there is an estimate within a range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely that changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives.

Environmental site remediation costs are deferred under regulatory approval from the OPUC and WUTC. In addition, the OPUC authorized a mechanism (SRRM) that allows the Company to recover prudently incurred environmental site remediation costs, subject to an earnings test. Actual cost recovery under SRRM depends upon offsetting future insurance recoveries, prudency review regarding future expenditures, and the impact of an earnings test. Cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding. We annually review all regulatory assets for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings in the period such determination is made. See Note 15 for information regarding the settlement agreement filed with the OPUC to resolve implementation issues for SRRM.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Item 3. Legal Proceedings). In the complaint, NW Natural sought damages in excess of the $50 million in losses it had incurred through the date of the complaint, as well as declaratory relief for additional losses it expected to incur in the future.

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other non-current liabilities on the balance sheet:

	Current Liabilities			Non-Current Liabilities		
	September 30,		December 31,	September 30,		December 31,
In thousands	2013	2012	2012	2013	2012	2012
Portland Harbor site:						
Gasco/Siltronic Sediments	$512	$1,748	$2,207	$38,034	$43,628	$36,087
Other Portland Harbor	1,812	1,188	1,767	2,315	3,186	3,160
Gasco Uplands site	2,094	18,018	18,722	7,126	7,453	5,028
Siltronic Uplands site	405	511	637	434	592	379
Central Service Center site	150	100	140	271	445	396
Front Street site	411	942	993	158	452	—
Oregon Steel Mills	—	—	—	179	185	185
Total	$5,384	$22,507	$24,466	$48,517	$55,941	$45,235

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The following table presents information regarding the total amount of cash paid for environmental sites and the total regulatory asset deferred:

	September 30,		December 31,
In thousands	2013	2012	2012
Cash paid	$93,264	$64,709	$71,124
Total regulatory asset deferral[1]	118,029	123,178	121,144

[1] Total regulatory asset deferral includes cash paid, remaining liability, and interest, net of insurance reimbursement.

PORTLAND HARBOR SITE. The Portland Harbor is an Environmental Protection Agency (EPA) listed Superfund site that is approximately 11 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands and Siltronic uplands sites. We have been notified that we are a potentially responsible party to the Superfund site and we have joined with other potentially responsible parties (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/Feasibility Study (RI/FS). The LWG submitted a draft Feasibility Study (FS) to the EPA in March 2012 that provides a range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of costs estimated for various remedial alternatives for the entire Portland Harbor, as provided in the draft FS, is $169 million to $1.8 billion. NW Natural's potential liability is a portion of the costs of the remedy the EPA will select for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 potentially responsible parties. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability. We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediments and Other Portland Harbor projects.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. NW Natural submitted a draft Engineering Evaluation/Cost Analysis (EE/CA) to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA range from $38.5 million to $350 million. We have recorded a liability of $34.0 million for the sediment clean-up, which reflects the low end of the EE/CA range. We have recorded an additional liability of $4.5 million for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

Other Portland Harbor. NW Natural incurs costs related to its membership in the LWG which is performing the RI/FS for EPA. NW Natural may also incur costs related to natural resource damages from these sites. In 2008, the Portland Harbor Natural Resource Trustee Council advised a number of potentially responsible parties that it intended to pursue natural resource damage claims at the Portland Harbor Superfund site. The Company and other parties have signed a cooperative agreement with the Natural Resource Trustees to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. Natural resource damage claims may arise only after a remedy for clean-up has been settled. We have accrued a liability for these claims which is at the low end of the range of the potential liability and the high end of the range cannot be reasonably estimated. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor.

GASCO UPLANDS SITE. NW Natural owns a former gas manufacturing plant that was closed in 1958 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality (ODEQ) Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.

In May 2007, we completed a revised Remedial Investigation Report for the uplands portion and submitted it to ODEQ for review. We have recognized a liability for this portion of the site remediation which is at the low end of the range of potential liability.

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In September 2013, we completed construction of a groundwater source control system at the Gasco site. We began operating the system in September and will continue monitoring the effects of the system with ODEQ. It is not clear at this time what, if any, additional ODEQ requirements and actions may be needed to meet the standards set by the ODEQ, subsequent to the initial testing of the system or as part of the final remedy for the uplands portion of the Gasco site. We have estimated a liability range from $0.3 million to $18 million, for which we have recorded an accrued liability at the low end of the range due to the uncertainty regarding ODEQ's requirements.

In October 2013, all parties agreed to open a new docket to separately review the prudence of the capital costs associated with constructing the source control system. On October 28, 2013, the Commission approved placing these Gasco construction costs into rates effective November 1, 2013 even though the OPUC has not yet approved the SRRM stipulation. These amounts are subject to refund, with interest, in the event the Commission determines, through this separate docket, that any of these costs were incurred imprudently. Under this approach, $19.0 million of costs were included in Oregon rates effective November 1. The prudency review for this project is expected to be completed early in 2014.

OTHER SITES. In addition to those sites above, we have environmental exposures at four other sites, Siltronic, Central Service Center, Front Street, and Oregon Steel Mills. Due to the uncertainty of the design of remediation, regulation, timing of the liabilities, and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites have been recognized at their respective low end of the range of potential liability and the high end of the range cannot be reasonably estimated. See “Legal Proceedings” below.

Legal Proceedings

NW Natural is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, NW Natural does not expect the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows. See also Part II, Item 1, “Legal Proceedings.”

OREGON STEEL MILLS SITE. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants, were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect that the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

14. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

During the first quarter of 2013, we identified an error in the rate used to calculate interest on certain regulatory assets. Accounting standards allow for the capitalization of all or part of an incurred cost that would otherwise be charged to expense if the regulator provides orders that create probable recovery of past costs through future revenues. Historically we had accrued interest as specified by regulatory order on certain regulatory balances at our authorized rate of return (ROR). This ROR includes both a debt and equity component, which we are allowed to recover from customers in the form of a carrying cost on regulatory deferred account balances. As the equity component of our ROR is not an incurred cost that would otherwise be charged to expense, this portion of the carrying cost should not have been capitalized for financial reporting purposes.

We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the annual and interim periods for 2013, if corrected in 2013. As a result, in accordance with accounting standards, we revised our prior period financial statements as described below to correct this error. The revision had no effect on reported cash flows.

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The adjustment impacted years 2003 through 2012 with a cumulative pre-tax decrease over that period of $5.6 million to regulatory assets and other income and expense. The revision decreased net income by $1.1 million, $0.9 million and $0.7 million for the years ended December 31, 2012, 2011 and 2010, respectively. The cumulative decrease to January 1, 2010 retained earnings was $0.7 million as a result of the revision.

The following table presents the income statement impacts of this revision for the years ended December 31:

	2012			2011			2010		
In thousands, except per share data	Reported Balance	Adjust-ment	Adjusted Balance	Reported Balance	Adjust-ment	Adjusted Balance	Reported Balance	Adjust-ment	Adjusted Balance
Other income and expense, net	$4,936	$(1,777)	$3,159	$4,523	$(1,411)	$3,112	$7,102	$(1,083)	$6,019
Income before income taxes	103,959	(1,777)	102,182	107,280	(1,411)	105,869	122,129	(1,083)	121,046
Income tax expense	44,104	(701)	43,403	43,382	(557)	42,825	49,462	(429)	49,033
Net Income	59,855	(1,076)	58,779	63,898	(854)	63,044	72,667	(654)	72,013
Comprehensive income	58,364	(1,076)	57,288	62,702	(854)	61,848	72,031	(654)	71,377
Basic EPS	2.23	(0.04)	2.19	2.39	(0.03)	2.36	2.73	(0.02)	2.71
Diluted EPS	2.22	(0.04)	2.18	2.39	(0.03)	2.36	2.73	(0.03)	2.70

The following table presents the balance sheet impacts of this revision as of December 31:

	2012			2011		
In thousands	Reported Balance	Adjustment	Adjusted Balance	Reported Balance	Adjustment	Adjusted Balance
Non-current assets:						
Regulatory assets	$387,888	$(5,633)	$382,255	$371,392	$(3,856)	$367,536
Total non-current assets	2,535,054	(5,633)	2,529,421	2,397,885	(3,856)	2,394,029
Total assets	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718
Liabilities and equity:						
Deferred credits and other non-current liabilities:						
Deferred tax liabilities	$446,604	$(2,227)	$444,377	$413,209	$(1,526)	$411,683
Total deferred credits and other non-current liabilities	1,025,584	(2,227)	1,023,357	975,922	(1,526)	974,396
Equity:						
Retained earnings	385,753	(3,406)	382,347	373,905	(2,330)	371,575
Total equity	733,033	(3,406)	729,627	714,488	(2,330)	712,158
Total liabilities and equity	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718

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The following tables present the income statement and balance sheet corrections for the following quarters:

	2012							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$1,005	$472	$921	$620	$1,710	$1,180	$1,300	$887
Income (loss) before income taxes	68,480	67,947	2,296	1,995	(13,594)	(14,124)	46,777	46,364
Income tax expense (benefit)	27,873	27,663	887	768	(3,036)	(3,245)	18,380	18,217
Net income (loss)	40,607	40,284	1,409	1,227	(10,558)	(10,879)	28,397	28,147
Comprehensive income (loss)	40,773	40,450	1,575	1,393	(10,391)	(10,712)	26,407	26,157
Basic EPS	1.52	1.50	0.05	0.05	(0.39)	(0.41)	1.06	1.05
Diluted EPS	1.51	1.50	0.05	0.05	(0.39)	(0.41)	1.05	1.04
Non-current assets:								
Regulatory assets	$368,521	$364,132	$366,981	$362,290	$367,692	$362,472	$387,888	$382,255
Total non-current assets	2,416,372	2,411,983	2,448,359	2,443,668	2,492,467	2,487,247	2,535,054	2,529,421
Total assets	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$438,486	$436,750	$440,073	$438,217	$430,885	$428,821	$446,604	$444,377
Total deferred credits and other non-current liabilities	999,028	997,292	991,007	989,151	985,729	983,665	1,025,584	1,023,357
Equity:								
Retained earnings	402,599	399,946	392,082	389,247	369,584	366,428	385,753	382,347
Total equity	745,971	743,318	737,570	734,735	717,559	714,403	733,033	729,627
Total liabilities and equity	2,727,262	2,722,873	2,635,141	2,630,450	2,690,368	2,685,148	2,818,753	2,813,120

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	2011							
	First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
In thousands, except per share data	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance	Reported Balance	Adjusted Balance
Other income and expense, net	$1,214	$1,291	$1,122	$779	$1,781	$1,426	$406	$(384)
Income (loss) before income taxes	68,627	68,704	3,509	3,166	(14,012)	(14,367)	49,156	48,366
Income tax expense (benefit)	27,854	27,884	1,316	1,181	(5,700)	(5,840)	19,912	19,600
Net income (loss)	40,773	40,820	2,193	1,985	(8,312)	(8,527)	29,244	28,766
Comprehensive income (loss)	40,919	40,966	2,339	2,131	(8,166)	(8,381)	27,610	27,132
Basic EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.08
Diluted EPS	1.53	1.53	0.08	0.07	(0.31)	(0.32)	1.09	1.07
Non-current assets:								
Regulatory assets	$345,452	$343,085	$326,081	$323,371	$328,757	$325,692	$371,392	$367,536
Total non-current assets	2,290,848	2,288,481	2,294,100	2,291,390	2,317,293	2,314,228	2,397,885	2,394,029
Total assets	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718
Liabilities and equity:								
Deferred credits and other non-current liabilities:								
Deferred tax liabilities	$396,357	$395,419	$398,825	$397,751	$394,217	$393,003	$413,209	$411,683
Total deferred credits and other non-current liabilities	873,714	872,776	874,842	873,768	866,927	865,713	975,922	974,396
Equity:								
Retained earnings	385,899	384,470	376,489	374,853	356,574	354,723	373,905	371,575
Total equity	723,228	721,799	714,628	712,992	696,605	694,754	714,488	712,158
Total liabilities and equity	2,571,553	2,569,186	2,521,994	2,519,284	2,567,840	2,564,775	2,746,574	2,742,718

In thousands, except per share data	Six Months Ended June 30, 2012 Reported Balance	Six Months Ended June 30, 2012 Adjusted Balance	Nine Months Ended September 30, 2012 Reported Balance	Nine Months Ended September 30, 2012 Adjusted Balance
Other income and expense, net	$1,926	$1,092	$3,636	$2,272
Income before income taxes	70,776	69,942	57,182	55,818
Income tax expense	28,760	28,431	25,724	25,186
Net Income	42,016	41,511	31,458	30,632
Comprehensive income	42,348	41,843	31,957	31,131
Basic EPS	1.57	1.55	1.17	1.14
Diluted EPS	1.56	1.54	1.17	1.14

15. SUBSEQUENT EVENTS

In July 2013, NW Natural filed stipulated settlement agreements for our working gas inventory and environmental dockets that resulted from certain decisions deferred by the OPUC from our 2012 general rate case. The working gas inventory settlement was approved by the OPUC on September 30, 2013 and resulted in an additional $0.5 million of revenues recognized in the third quarter of 2013. Regarding the environmental docket, in October 2013, all parties supported moving the prudence review of the Gasco water treatment station to a separate docket out of the overall environmental settlement. See "Gasco Water Treatment Station" below for additional detail on this docket. The environmental docket remains open and subject to Commission review and approval. The Company anticipates a decision on the proposed settlement in the first half of 2014. See "Environmental Cost (SRRM) Settlement" below.

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Gasco Water Treatment Station
On September 6, 2013, we filed testimony with the OPUC addressing the prudence of the capital costs associated with constructing a water treatment station at our Gasco site. This was done with the intent that the costs of the project be recovered in rates beginning November 1, 2013, in accordance with the all-parties stipulation that was submitted in our SRRM docket. On October 28, 2013, the Commission approved placing these costs into rates effective November 1, 2013 even though the Commission has not yet approved the SRRM stipulation. These amounts are subject to refund, with interest, in the event the Commission determines, through this separate docket, that any of these costs were incurred imprudently. Under this approach, $19.0 million of costs were included in Oregon rates effective November 1. These costs were included in regulatory assets on the balance sheet at September 30, 2013 and were subsequently moved to property, plant, and equipment when approval was received on October 28, 2013. The prudency review for this project is expected to be completed early in 2014.

Environmental Cost (SRRM) Settlement
The environmental settlement addresses implementation issues related to the new environmental recovery mechanism (SRRM). The environmental settlement is still subject to the Commission's review and approval. The Company anticipates a decision on this matter in the first half of 2014.

If the Commission approves the settlement as filed, it would resolve SRRM implementation issues including a review of the prudence of past deferred expenses, as well as the creation and application of an earnings test to determine the amount of environmental costs that would be collected from customers based on the Company's past and future earnings.

Under the settlement agreement, if approved, approximately $97.6 million of environmental remediation expenses and associated carrying costs incurred by NW Natural through December 31, 2012 would be deemed prudently incurred while $33 thousand would be disallowed. It would also be agreed that insurance settlements finalized through 2012 (approximately $40.7 million) were prudently executed, with these recoveries applied against deferred expenses to reduce amounts amortized under the SRRM. As part of the settlement, NW Natural would agree not to seek recovery of $7.0 million of its $97.6 million in deferred expenses and associated carrying costs incurred through December 31, 2012. If the OPUC approves the settlement, this disallowance and other related adjustments would result in a one-time, net after-tax charge of $3.4 million.

The settlement also would provide that environmental remediation expenditures deferred after January 1, 2013 be reviewed annually for prudency, and an earnings test will be applied annually as follows:

- If NW Natural's Oregon utility results of operations (ROO) for a given year show that NW Natural's earnings were more than 75 basis points below its authorized return on equity in that year (Authorized ROE), NW Natural would be allowed to collect all of the prudently incurred environmental remediation expenses deferred in that year.
- If NW Natural's ROO for a given year shows that its earnings are between 75 basis points below Authorized ROE and Authorized ROE (or at Authorized ROE), NW Natural would reduce the balance of the SRRM account up to the net amount deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year (Net Amount Deferred), by 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are above Authorized ROE but less than or equal to 50 basis points above Authorized ROE, NW Natural will reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year, by: (1) 80% of NW Natural's earnings between Authorized ROE and 50 basis points above Authorized ROE; and (2) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are more than 50 basis points above Authorized ROE, NW Natural would reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year,

including offsetting insurance proceeds and other third-party recoveries allocated to that year, by: (1) 95% of its earnings above 50 basis points above Authorized ROE; (2) 80% of its earnings between Authorized ROE and 50 basis points above Authorized ROE; and (3) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.

Any insurance proceeds recovered after December 31, 2012 would be applied against expenses approved for amortization in the SRRM in equal amounts over the 10-year period following receipt of the funds.

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

The following is management's assessment of Northwest Natural Gas Company's (NW Natural or the Company) financial condition, including the principal factors that affect results of operations. The disclosures contained in this report refer to our consolidated activities for the three and nine months ended September 30, 2013 and 2012. Unless otherwise indicated, references below to "Notes" are to the Notes to Unaudited Consolidated Financial Statements in this report. A significant portion of our business results are seasonal in nature, and as such the results of operations for these three and nine month periods are not necessarily indicative of expected fiscal year results. Therefore, this discussion should be read in conjunction with our 2012 Annual Report on Form 10-K (2012 Form 10-K).

The consolidated financial statements include NW Natural, the parent company, and its direct and indirect wholly-owned subsidiaries. Selected subsidiaries are depicted and organized as follows:

We operate in two primary reportable business segments, local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as "other." We refer to our local gas distribution business as the "utility," and our "gas storage" and "other" business segments as "non-utility." Our utility segment includes our NW Natural local gas distribution business, NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Our "other" segment includes NWN Energy's equity investment in Palomar Gas Holdings, LLC (PGH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary, Palomar Gas Transmission, LLC (Palomar), and NNG Financial's equity investment in Kelso-Beaver Pipeline (KB Pipeline). Our equity investments, PGH and KB Pipeline, are not depicted in the chart above. For a further discussion of our business segments, see Note 4.

In addition to presenting results of operations and earnings amounts in total, certain financial measures are expressed in cents per share, which is a non-GAAP financial measure. These amounts reflect factors that directly impact earnings. In calculating these financial disclosures, we allocate income tax expense based on the effective tax rate, where applicable. All references in this section to earnings per share (EPS) are on the basis of diluted shares (see Part II, Item 8., Note 3, "Earnings Per Share," in our 2012 Form 10-K). We use such non-GAAP measures in analyzing our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

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EXECUTIVE SUMMARY

Key financial highlights include:

	Three Months Ended September 30,		
In thousands, except per share data	2013	2012	Change
Consolidated net income (loss)	$(8,233)	$(10,879)	$2,646
Consolidated earnings (loss) per share	(0.31)	(0.41)	0.10
Utility margin	47,050	42,331	4,719

THREE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The primary factors contributing to improved third quarter results were as follows:

- lower consolidated net loss primarily due to higher utility margin and an increase in income tax benefit compared to last year due to a one-time tax charge taken in 2012 from an Oregon general rate case disallowance. Partially offsetting these factors were higher operations and maintenance expenses; and
- higher utility margin primarily due to customer growth, rate-base return on our gas reserve investment, and revenue timing impacts. Partially offsetting this margin increase were lower gains from gas cost savings. See "Business Segments - Local Gas Distribution "Utility" Operations—Timing Impacts" below for additional information on revenue timing impacts.

In addition to financial results for the third quarter of 2013, we also continued to make progress on several key initiatives including:

- OPUC approval to recover carrying costs on working gas inventory, which resolved an open item from our 2012 Oregon general rate case. See "Results of Operations—Regulatory Matters—General Rate Cases—Working Gas Inventory Settlement Approval" below for more detail;
- first place ranking for customer satisfaction in the 2013 J.D. Power and Associates Study for the West among gas utilities and the highest score in the nation, marking the 10th consecutive year of high rankings; and
- we continue to plan and evaluate a storage expansion at our Mist facility, which could include the development of gas storage wells, a compressor station, and additional pipeline facilities.

Our progress on, and commitment to, these initiatives are a part of our core business objectives and long-term strategic plan. See Part II, Item 7, “2013 Outlook” in our 2012 Form 10-K and "Strategic Opportunities" below.

Issues, Challenges, and Performance Measures

ECONOMY. The local, national, and global economies continued to show some signs of growth during the third quarter of 2013; however, the recovery remains slow. Our utility’s annual customer growth rate was 1.1% at September 30, 2013, compared to 1.0% at September 30, 2012. The unemployment rate in our region declined to under 8% in 2013 from over 11% in 2009. New housing permits are increasing in Oregon and Southwest Washington compared to last year. We will continue to monitor the economy, and believe our utility business is well positioned to continue adding customers and serve increased energy demand as the economy recovers because of the competitive price advantage of natural gas over other energy supplies, our relatively low market penetration, and our ongoing focus on converting homes and businesses to natural gas. Additionally, we expect more industrial customers to switch to natural gas due to its price advantage over oil, propane, and other fuels. Further, government and regulatory policies that favor lower carbon emissions and lower cost energy alternatives such as natural gas could increase demand for our services in the future.

GAS PRICES AND SUPPLIES. Our gas acquisition strategy is to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices so we can effectively manage costs, reduce price volatility, and maintain a competitive advantage. With recent developments in drilling technologies and the abundance of shale plays around the U.S. and in Canada, the current outlook for North American natural gas supply is strong and is projected to remain this way well into the future. The continuation of low and stable gas prices in the future depends on a combination of supply outlook and demand factors as well as a regulatory environment that continues to support hydraulic fracturing and other drilling technologies.

Our utility's annual Purchased Gas Adjustment (PGA) mechanisms in Oregon and Washington, combined with our gas price hedging strategies, enable us to reduce earnings exposure for the Company and secure low, stable gas costs for our customers. We typically hedge gas prices for approximately 75% of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2012-13 gas year (November 1, 2012 – October 31, 2013) hedged at 75% of our forecasted sales volumes, including 47% in financial swaps and option contracts and 28% in physical gas supplies. Our physical hedges consist of a combination of gas inventories in storage, local gas production from the Mist area, and supply region production from our utility gas reserve investment. For further discussion of gas reserves, see “Strategic Opportunities—Gas Reserves” below. See also "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" below.

In addition to the amount hedged for the current gas contract year, we were also hedged at approximately 75% as of September 30, 2013 for the upcoming 2013-14 gas year and between 8% and 33% hedged for annual requirements over the following five gas years. Our hedge levels are subject to change based on actual load volumes, which depend, to a certain extent, on weather and economic conditions. Also, our storage inventory levels may increase or decrease based on storage expansion, storage contracts with third parties, or storage recall by the utility.

Although less expensive and more stable gas prices provide opportunities to manage costs for our utility customers, they also present challenges for our gas storage businesses by lowering the price of, and reducing the demand for, storage services. Consequently, our ability to sign storage contracts with customers at favorable prices affects our financial results. However, if there is an increase in demand for natural gas or a decrease in drilling activity, there may be upward pressure on gas prices or an increase in gas price volatility, which may result in increased demand or prices for storage services. In the short-term, we continue to investigate opportunities for increasing revenues, lowering costs, and developing enhanced services for storage customers.

ENVIRONMENTAL COSTS. We accrue all environmental loss contingencies related to environmental sites for which we are responsible. Due to numerous uncertainties surrounding the nature of environmental investigations and the development of remediation solutions approved by regulatory agencies, actual costs could vary significantly from our estimates. As a regulated utility, we are allowed to defer certain costs pursuant to regulatory orders. In our most recent general rate case, the Public Utility Commission of Oregon (OPUC) approved the recovery of environmental costs from investigation and site remediation subject to certain conditions as noted in "Results of Operations—Regulatory Matters—Rate Mechanisms" below.

We also recover some of our environmental costs from insurance policies and only seek recovery from customers for amounts not covered by insurance. Ultimate recovery of environmental costs from regulated utility rates will depend on our ability to effectively manage these costs and demonstrate that costs were prudently incurred, and the impact of cost sharing, if any, under the annual earnings test in Oregon. See "Results of Operations—Regulatory Matters—General Rate Cases—Environmental Settlement" below for more detail on the stipulated settlement filed with the OPUC, which outlines implementation issues regarding the Site Remediation and Recovery Mechanism's (SRRM) earnings test. Also, environmental cost recovery and carrying charges on amounts charged to Washington customers will be reviewed and determined in a future proceeding. See also "Results of Operations—Regulatory Matters—General Rate Cases—Gasco Water Treatment Station" below for information regarding the regulatory treatment of our Gasco environmental site.

See Part II, Item 7, “Issues, Challenges, and Performance Measures” in our 2012 Form 10-K for a discussion of our performance metrics.

Strategic Opportunities

SAFETY, RELIABILITY, AND SERVICE. We are committed to customer and employee safety, operational effectiveness, and service quality, as each is a means of strengthening our customer relationship and leveraging our competitive position. We have several ongoing initiatives designed to improve the quality, effectiveness, and integrity of our utility and non-utility business operations. To this end, we have upgraded several facilities enhancing our business continuity, employee training, safety, productivity, and energy efficiency. Our initiatives in 2013 reflect our continued commitment to safety and service. For example, the Company recently increased staffing levels in the areas of pipeline safety, emergency response, regulatory compliance, field training, and customer service. In addition, we recently agreed to a plan with the OPUC whereby we will accelerate the completion of our bare steel pipe replacement program by the end of 2015, which is several years ahead of the original schedule.

GAS STORAGE. We own and operate two underground gas storage facilities - the Mist facility in Oregon and the Gill Ranch facility near Fresno, California. Storage operations benefit from seasonal swings in commodity pricing and market volatility. Our storage facilities position us to capitalize on rising demand for natural gas, higher gas prices, or increased market volatility. Recently however, volatility in natural gas prices has been near all-time lows, thus creating fewer opportunities to capitalize on our storage facilities. However, if there is an increase in demand for natural gas, a decrease in supply or drilling activity, or potentially other changes that impact the gas supply or demand balance, then we would likely see upward pressure on natural gas prices and an increase in price volatility. If market conditions do change, we have the ability to expand both storage facilities beyond their current capacities.

The Pacific Northwest storage market has been impacted by lower gas prices and a lack of gas price volatility, although less than in California. The need for new flexible gas-fired generation has been identified in the Pacific Northwest region to integrate intermittent wind resources into the power system, thereby increasing the associated need for gas storage. To address this need, we are in the early planning stages of a new expansion at Mist. If completed, this expansion would be anchored by an agreement to provide gas storage services to Portland General Electric (PGE) to support gas-fired generation facilities at Port Westward, Oregon. The Mist expansion project is subject to several conditions, including, but not limited to, PGE's approval of projected costs and timelines and its notice to proceed with the project, NW Natural's filing and approval by the OPUC of a new rate schedule for this service, as well as NW Natural receiving required permits and regulatory approvals for the project. This expansion would likely include the development of new storage wells, a compressor station, and additional pipeline facilities that would also enable more storage expansions in the future. If the project proceeds as currently planned, the earliest timeframe for completing the expansion would be 2017.

In addition, we currently estimate that the Gill Ranch storage facility could support an additional 25 Bcf of storage capacity, bringing the total storage capacity to approximately 45 Bcf, of which our current rights would give us up to an additional 7.5 Bcf or ownership of a total of approximately 22.5 Bcf. An expansion at the Gill Ranch storage facility would require certain infrastructure investments, but no further expansion of our gas transmission pipeline.

PIPELINE DIVERSIFICATION. Currently, our utility operations and gas storage operations at Mist depend on a single bi-directional interstate transmission pipeline to ship gas supplies to customers. We continue to work with regulators and utilities in the Pacific Northwest to advance a new integrated regional cross-Cascades pipeline through our Palomar investment to reduce this risk and create regional diversity and increased reliability for our system.

The Federal Energy Regulatory Commission (FERC) will regulate the proposed pipeline. Palomar Gas Transmission, LLC (Palomar) intends to file an application with FERC for a pipeline delivering gas from the GTN pipeline near Madras in central Oregon to a NW Natural hub near Molalla, Oregon. The application is expected to be filed after NW Natural has received OPUC and Washington Utilities and Transportation Commission (WUTC) acknowledgment of its filed resource plans, including this proposed pipeline, and after Palomar has conducted a new open season to obtain adequate commercial support for the pipeline. The approval and timing for potential construction of the pipeline will depend on the project being competitive with alternative Pacific Northwest pipeline projects, as well as being able to obtain regulatory permits and the necessary commercial support from shippers. See Note 11 for further discussion.

GAS RESERVES. In addition to hedging gas prices with commodity-based financial derivative contracts, we entered into an agreement with Encana Oil & Gas (USA) Inc. (Encana) in 2011 to hedge a portion of our Oregon utility customers' cost of gas over an estimated period of 30 years. Under this agreement, we have invested in working interests in certain gas leases in a field located in Sublette County, Wyoming. During the first 10 years of the contract, we forecast the volumes of gas to be produced under the gas reserves agreement sufficient to hedge approximately 8% to 10% of our average annual utility gas supply requirements. We receive certain federal tax deductions for drilling costs incurred under our gas reserves agreement. The timing of when we realize these federal tax benefits has been affected by net operating losses (NOLs) for tax purposes, which will be carried forward to reduce our current tax liability in future years. We also continue to evaluate additional investments in gas reserves as part of our ongoing gas hedging strategy. See Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves" in our 2012 Form 10-K.

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CONSOLIDATED EARNINGS AND DIVIDENDS

Consolidated Earnings
Consolidated highlights include:

In thousands, except per share data	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Consolidated operating revenues	$88,195	$87,501	$497,770	$501,131	$694	$(3,361)
Consolidated operating expenses	91,982	92,297	414,268	415,422	(315)	(1,154)
Consolidated interest expense, net	11,347	10,508	33,543	32,163	839	1,380
Consolidated net income (loss)	(8,233)	(10,879)	31,532	30,632	2,646	900
Consolidated earnings (loss) per share	(0.31)	(0.41)	1.17	1.14	0.10	0.03

THREE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The primary factors contributing to the lower consolidated net loss were:

- a $4.7 million increase in utility margin primarily due to:
  - revenue timing impacts from changes in fixed monthly charges and the decoupling baseline in rates from our 2012 Oregon general rate case. See "Business Segments - Local Gas Distribution "Utility" Operations—Timing Impacts" below for additional information;
  - customer growth of 1.1% over the last 12 months; and
  - rate-base return on our gas reserve investment.
- a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance.

Partially offsetting these increases was a $3.7 million increase in operations and maintenance expense due to increased utility payroll and system maintenance and safety costs, as well as a $0.8 million increase in interest expense.

NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The primary factors contributing to the increase in consolidated net income were:

- a $2.2 million increase in utility margin primarily due to:
  - customer growth;
  - rate-base return on our gas reserve investment; and
  - revenue timing impacts from changes in fixed monthly charges and the decoupling baselines set in rates from our 2012 Oregon general rate case. See "Business Segments - Local Gas Distribution "Utility" Operations—Timing Impacts" below for additional information.

  Partially offsetting these gains was a lower contribution to utility margin from our gas cost incentive sharing mechanism.
- a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance.

Partially offsetting these increases was a $4.1 million increase in operations and maintenance expense due to higher utility payroll expenses and system maintenance and safety costs, which were partially offset by a decrease in bad debt expense. In addition, there was a $1.4 million increase in interest expense.

Dividends
Dividend highlights include:

Per common share	Three Months Ended September 30, 2013	2012	Change
Dividends paid	$0.455	$0.445	$0.01

The Board of Directors declared a quarterly dividend on our common stock of 46.0 cents per share, payable on November 15, 2013, to shareholders of record on October 31, 2013, reflecting an indicated annual dividend rate of $1.84 per share.

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RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation by the OPUC, WUTC, and FERC with respect to, among other matters, rates, and terms of service. The OPUC and WUTC also regulate our systems of accounts and the issuance of securities by our utility. In 2012, approximately 90% of our utility gas volumes and revenues were derived from Oregon customers, with the remaining 10% from Washington customers. Earnings and cash flows from utility operations are largely determined by rates set in general rate cases and other regulatory proceedings in Oregon and Washington, but are also affected by the local economies in Oregon and Washington, the pace of customer growth in the residential and commercial markets, and our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of our utility-related costs, including operating expenses and investment costs in utility plant and other regulatory assets. See "General Rate Cases" below.

GAS STORAGE. Our gas storage business is subject to regulation by the OPUC, California Public Utilities Commission (CPUC), and FERC with respect to, among other matters, rates and terms of service. The OPUC and CPUC also regulate the issuance of securities and our system of accounts. The OPUC and FERC regulate intrastate and interstate storage services, respectively, under a cost of service model which allows for storage prices to be set at or below the cost of service as approved by each agency in the last regulatory filing. The CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace.

See Part II, Item 7, “Results of Operations—Regulatory Matters,” in the 2012 Form 10-K.

General Rate Cases

OREGON. In our most recent general rate case, the OPUC authorized rates to customers based on an ROE of 9.5%, an overall rate of return of 7.78%, and a capital structure of 50% common equity and 50% long-term debt. These customer rates went into effect on November 1, 2012.

DEFERRED DOCKETS. The following items were deferred for decision by the Commission in separate dockets:

- Working Gas Inventory - the Company requested that its working gas inventory balance be included in rate base and the Company be allowed a return on this investment. On September 30, 2013, the OPUC approved an all-party settlement agreement that provides a carrying cost based on the Company's overall rate of return. See "Working Gas Inventory Settlement Approval" below for additional information;
- Site Remediation and Recovery Mechanism (SRRM) - the Company requested recovery of its deferred environmental cost balance in its last rate case and was granted an SRRM. The Commission ordered a separate docket in order to determine an earnings test that would be applied to these and future deferred expenses, and to review the Company's past deferred expenses for prudence. In July 2013, all parties in this SRRM docket filed a settlement agreement with the OPUC to address how to apply this new regulatory recovery mechanism. See "Environmental Settlement" and "Environmental Costs" below;
- Interstate Storage Sharing - a docket has been opened to review the current revenue sharing arrangement whereby we allocate to utility customers a portion of the net revenues generated from non-utility Mist storage services and third-party asset management services; and
- Prepaid Pension Assets - the Company requested in its last rate case that prepaid pension assets be included in rate base and allowed a return on the investment. A separate docket was ordered by the OPUC to review the rate treatment of pensions on a general, non-utility-specific basis. The pension docket is currently open. Until a decision is reached regarding the treatment of pension assets, the OPUC has authorized NW Natural to continue collecting pension expense based on the amounts set in our 2003 Oregon general rate case and to defer into a regulatory balancing

account the difference between actual expense and collected expense for future rate recovery.

We anticipate a Commission decision on the stipulation filed in the SRRM docket, as well as resolution of the interstate storage sharing and prepaid pension assets dockets during the first half of 2014.

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WORKING GAS INVENTORY SETTLEMENT APPROVAL. The working gas inventory carrying costs settlement agreement was approved on September 30, 2013, which allows the Company to include approximately $39.5 million of working gas inventory in rate base and recover approximately $4.5 million in carrying costs. We had previously been accruing earnings of $4.0 million related to working gas carrying costs for 2013 based on the amount of working gas inventory proposed in our 2012 general rate case. This approved amount of $4.5 million was included in the PGA rates that became effective November 1, 2013.

ENVIRONMENTAL SETTLEMENT. In July 2013, NW Natural filed a stipulated settlement with all parties to resolve the open SRRM docket from the 2012 Oregon general rate case. The environmental settlement is still subject to the Commission's review and approval. The Company anticipates a decision on this matter in the first half of 2014.

In October 2013, all parties agreed to open a separate docket to review the prudence of costs spent to construct the Gasco water treatment site. See "Gasco Water Treatment Station" below for more information on this docket.

If approved as filed, the SRRM settlement agreement would resolve all remaining implementation issues, including a review of the prudence of past deferred expenses, as well as the creation and application of an earnings test to determine the amount of costs that would be collected from customers based on the Company's past and future earnings.

Under the settlement agreement if approved, approximately $97.6 million of environmental remediation expenses and associated carrying costs incurred by NW Natural through December 31, 2012 would be deemed prudently incurred, while $33 thousand would be disallowed. The settlement also specifies that insurance settlements finalized through 2012 (approximately $40.7 million) were entered into prudently, with these recoveries applied against deferred environmental costs to reduce amounts amortized under the SRRM. As part of the settlement, NW Natural would agree not to seek recovery of $7.0 million of its $97.6 million in deferred expenditures and associated carrying costs incurred through December 31, 2012. If the OPUC approves the settlement, this amount and other related adjustments would result in a one-time, net after-tax charge of $3.4 million.

The settlement agreement would also provide that environmental remediation expenditures deferred after January 1, 2013 would be reviewed annually for prudency, and an earnings test applied as follows:

- If NW Natural's Oregon utility results of operations (ROO) for a given year show that NW Natural's earnings were more than 75 basis points below its authorized return on equity in that year (Authorized ROE), NW Natural would be allowed to collect all of the prudently incurred environmental remediation expenses deferred in that year.
- If NW Natural's ROO for a given year shows that its earnings are between 75 basis points below Authorized ROE and Authorized ROE (or at Authorized ROE), NW Natural would reduce the balance of the SRRM account up to the net amount deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year (Net Amount Deferred), by 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are above Authorized ROE but less than or equal to 50 basis points above Authorized ROE, NW Natural would reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year by: (1) 80% of NW Natural's earnings between Authorized ROE and 50 basis points above Authorized ROE; and (2) 10% of its earnings between 75 basis points below Authorized ROE and Authorized ROE.
- If NW Natural's ROO for a given year shows that its earnings are more than 50 basis points above Authorized ROE, NW Natural would reduce the balance of the SRRM account, up to the Net Amount Deferred for the current year, including offsetting insurance proceeds and other third-party recoveries allocated to that year by: (1) 95% of its earnings above 50 basis points above Authorized ROE; (2) 80% of its earnings between Authorized ROE and 50 basis points above Authorized ROE; and (3) 10% of its earnings between 75 basis points below Authorized ROE and

Authorized ROE.

For example, assuming that the amount of NW Natural's current Oregon rate base remains unchanged and that NW Natural earned its Authorized ROE (currently 9.5%) when the earning test was applied, NW Natural would not recover approximately the first $0.6 million of its net environmental remediation expenditures for that year.

Any insurance proceeds recovered after December 31, 2012 will be applied against expenses approved for amortization in the SRRM in equal amounts over the 10-year period following receipt of the funds.

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GASCO WATER TREATMENT STATION. On September 6, 2013, we filed testimony with the OPUC addressing the prudence of the capital costs associated with constructing a water treatment station at our Gasco site. This was done with the intent that the costs of the project be recovered in rates effective November 1, 2013, in accordance with the all-parties stipulation that was submitted in our SRRM docket. On October 28, 2013, the Commission approved placing these costs into rates on November 1, 2013 even though the OPUC has not yet approved the SRRM stipulation. These amounts are subject to refund, with interest, in the event the Commission determines, through this separate docket, that any of these costs were incurred imprudently. Under this approach, $19.0 million of costs were included in Oregon rates effective November 1. The prudency review for this project is expected to be completed early in 2014.

Rate Mechanisms

PURCHASED GAS ADJUSTMENT. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases. This includes updated forecasts of gas prices for unhedged spot purchases and contract supplies, as well as gas prices hedged with financial derivatives, gas prices from the withdrawal of storage inventories, gas prices related to the production of gas reserves, interstate pipeline demand costs, the application of temporary rate adjustments to amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

In October 2013, the OPUC and WUTC approved PGA rate changes effective November 1, 2013. The effect of these rate changes was to increase the average monthly bills of residential customers by 1.5% in both Oregon and Washington. This was the first PGA rate increase in five years for both states, reflecting annual adjustments for changes in wholesale costs of natural gas as well as some additional changes to Oregon rate base.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20% or 10% of the difference between actual and estimated gas costs, respectively. For both the 2012-2013 and 2013-2014 PGA years, we selected the 90% deferral option. Under the Washington PGA mechanism, we defer 100% of the higher or lower actual gas costs, and those gas cost differences are passed on to customers through the annual PGA rate adjustment.

SYSTEM INTEGRITY PROGRAM (SIP). In Oregon, the OPUC has approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program and distribution integrity management program and the related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). This cost recovery approach is referred to as our System Integrity Program, or SIP. The OPUC has extended the application of SIP through November of 2014, after which time NW Natural may seek authorization to extend or modify it. We record the costs related to the integrity management program as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period, and recover the revenue requirement associated with these costs, subject to audit, through rate changes effective with the annual PGA. As such, our SIP costs in Oregon are tracked into rates with the annual PGA filing, except that the first $4 million of capital costs, and any amounts over the annual cap on expenditures of $12 million, are not included in the amounts tracked into rates in the PGA process. Instead, NW Natural would seek to have these amounts included in rate base at the time of our next general rate case, and these costs are therefore subject to normal regulatory lag until that time.

During the second quarter of 2013, the Commission approved a stipulation under which we received a temporary increase to the annual cap, authorizing an additional total $13.7 million of expenditures over the next two years to be tracked into rates. With the increased cap, we plan to substantially complete our bare steel replacement by the end of 2015, and as a result this stipulation precludes us from tracking any additional bare steel replacement costs into rates after 2015.

ENVIRONMENTAL COSTS. The OPUC has authorized the deferral of environmental costs associated with certain named sites and the accrual of a carrying cost on amounts deferred, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and accrual of

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carrying costs was extended through January 2014. For a discussion of costs associated with the Gasco Water Treatment Station see "Gasco Water Treatment Station" above.

The SRRM approved in the 2012 Oregon rate case allows the Company to recover prudently incurred environmental site remediation costs, net of insurance recoveries. The SRRM allows recovery of one-fifth of the Company's currently deferred environmental expenses and future expenses as incurred each year in rates on a rolling basis until all such expenses are recovered, subject to an annual prudence review. Recovery of these incurred costs will also be subject to an annual earnings test, which is currently being considered by the OPUC. For more detail on the proposed all-party settlement on the earnings test, see "General Rate Cases--Environmental Settlement" above.

The WUTC has also authorized the deferral of environmental costs allocated to Washington customers. This order was effective January 26, 2011 with cost recovery and carrying charges to be determined in a future proceeding. Based on the future Washington proceeding and our filed proposed settlement in Oregon noted above, recovery may vary significantly from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable. The settlement also addresses the allocation of costs to Oregon customers, but the allocation to Washington customers has not been reviewed for a final determination. For detail on the Oregon environmental settlement proposal, see "General Rate Cases--Environmental Settlement" above and Note 15. Also see Note 13 for further discussion of our regulatory and insurance recovery of environmental costs.

PENSION DEFERRAL. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. These deferred balances include the recognition of accrued interest on the account balance at the utility’s actual cost of long-term debt. However, upon collection of these deferred balances, we also recognize and recover the regulated allowed cost of equity for the portion of our weighted average cost of capital as specified by the OPUC. The deferral of operations and maintenance expense in 2012 was $7.9 million. Future years’ deferrals will depend on changes in plan assets and projected benefit liabilities based on a number of key assumptions, and on the amount of our pension contributions. We estimate pension expense deferrals totaling approximately $8 million in 2013, with $2.2 million and $6.8 million deferred for the three and nine months ended September 30, 2013, respectively.

As noted above, the Company continues to seek rate treatment in Oregon for amounts invested in prepaid pension assets in a separate docket which is currently open. A decision in this docket is expected in the first half of 2014.

CUSTOMER CREDITS FOR GAS STORAGE SHARING. In the second quarter of 2013, the Company received regulatory approval to provide its Oregon utility customers with an $8.8 million interstate storage credit included in their June bills. These customer credits were part of our regulatory incentive sharing mechanism related to non-utility Mist storage services and asset management services. Last year, the OPUC approved a $9.2 million credit to Oregon customers.

For a discussion of other rate mechanisms, see Part II, Item 7, “Results of Operations—Regulatory Matters—Rate Mechanisms” in our 2012 Form 10-K.

Business Segments - Local Gas Distribution "Utility" Operations

Our utility margin results are largely affected by customer growth and, to a certain extent, by changes in volume due to weather, and customers’ gas usage patterns because a significant portion of our utility margin is derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff (also called the decoupling mechanism), which adjusts utility margin up or down each month through a deferred accounting adjustment to offset changes resulting from increases or decreases in average use by residential and commercial customers. We also have a weather normalization tariff in Oregon, which adjusts customer bills up or down to offset changes in utility margin resulting from above- or below-average temperatures during the winter heating season. Both mechanisms are designed to reduce the volatility of our utility's earnings and customer charges. See "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2012 Form 10-K for more information on our decoupling and weather normalization mechanisms.

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Utility segment highlights include:

In thousands, except per share data	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Utility net income (loss)	$(9,605)	$(12,174)	$27,083	$27,424	$2,569	$(341)
Earnings (loss) per share - utility segment	$(0.36)	$(0.46)	$1.00	$1.02	$0.10	$(0.02)
Gas sold and delivered (therms)	159,133	158,364	771,420	785,540	769	(14,120)
Utility margin[1]	$47,050	$42,331	$239,151	$236,921	$4,719	$2,230

[1] See Utility Margin Table below for additional detail.

THREE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The primary factors contributing to the decrease in net loss were as follows:

- a $4.7 million increase in utility margin primarily due to:
  - a $5.3 million increase related to timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 Oregon general rate case; and
  - a $1.2 million increase from customer growth and the rate-base return on our gas reserve investment.

  Partially offsetting these increases was a $0.4 million decrease in gains from gas cost incentive sharing.
- a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance.

Partially offsetting the above factors were:

- a $3.5 million increase in operations and maintenance expense due to increases in utility payroll expenses and system maintenance and safety costs;
- a $1.0 million increase in interest expense primarily due to increases in long-term debt outstanding; and
- a $0.5 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment.

Total utility volumes sold and delivered remained relatively flat this quarter compared to the same quarter last year.

NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The primary factors contributing to the decrease in net income were as follows:

- a $4.2 million increase in operations and maintenance expense due to increases in utility payroll expenses and system maintenance and safety costs, partially offset by a decrease in bad debt expense;
- a $2.1 million increase in depreciation and amortization expenses primarily due to a higher level of investment in utility property, plant, and equipment; and
- a $1.7 million increase in interest expense primarily due to increases in long-term debt outstanding.

Partially offsetting the above factors were:

- a $2.2 million increase in utility margin primarily due to:
  - a $5.1 million increase related to customer growth and the rate-base return on our gas reserve investment; and
  - a $3.1 million increase related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 rate case.

  Partially offsetting these increases was a $3.3 million decrease in gains from gas cost incentive sharing due to actual gas prices that were roughly equivalent to estimated PGA prices for the current year as compared to actual gas prices that were lower than estimated PGA prices for the prior year and a $0.9 million decrease related to the general rate decrease primarily reflecting the lower Oregon Authorized ROE of 9.5%.

a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance.

Total utility volumes sold and delivered decreased 2% over last year primarily due to the impact of warmer weather on residential and commercial use.

TIMING IMPACTS. As a result of changes to the utility's baseline for average use per customer included in the 2012 Oregon general rate case, the decoupling mechanism's results this year will not be comparable to last year. Also, customers' fixed monthly charges were increased in the rate case, which allows the Company to recover more

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of its costs through a higher fixed monthly charge, rather than through a higher volumetric charge, which is more seasonal in nature. These changes negatively impacted our margin and net income results in the fourth quarter of 2012 and the first quarter of 2013, but positively impacted both the second and third quarter results of 2013. Overall, the current rate structure provides a more even distribution of revenues and earnings throughout the year.

UTILITY MARGIN TABLE. The following table summarizes the composition of utility gas volumes, revenues, and costs of sales.

In thousands, except degree day and customer data	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	Favorable/(Unfavorable) QTR	YTD
Utility volumes (therms):						
Residential and commercial sales	54,052	53,486	426,029	437,416	566	(11,387)
Industrial sales and transportation	105,081	104,878	345,391	348,124	203	(2,733)
Total utility volumes sold and delivered	159,133	158,364	771,420	785,540	769	(14,120)
Utility operating revenues:						
Residential and commercial sales	$67,584	$64,120	$434,105	$434,840	$3,464	$(735)
Industrial sales and transportation	14,625	15,988	49,373	51,531	(1,363)	(2,158)
Other revenues	600	2,048	3,371	5,061	(1,448)	(1,690)
Less: Revenue taxes	2,104	2,255	12,542	12,688	(151)	(146)
Total utility operating revenues	80,705	79,901	474,307	478,744	804	(4,437)
Less: Cost of gas	33,655	37,570	235,156	241,823	(3,915)	(6,667)
Utility margin	$47,050	$42,331	$239,151	$236,921	$4,719	$2,230
Utility margin:(1)						
Residential and commercial sales	$39,975	$33,154	$214,681	$207,284	$6,821	$7,397
Industrial sales and transportation	6,502	6,727	20,747	21,114	(225)	(367)
Miscellaneous revenues	723	668	3,494	3,634	55	(140)
Gain from gas cost incentive sharing	92	467	221	3,556	(375)	(3,335)
Other margin adjustments	(242)	1,315	8	1,333	(1,557)	(1,325)
Utility margin	$47,050	$42,331	$239,151	$236,921	$4,719	$2,230
Actual degree days	86	58	2,581	2,717		
Percent colder (warmer) than average weather(2)	(9)%	(43)%	(2)%	2%		

Customers:	As of September 30, 2013	2012	Change
Residential customers	621,625	615,642	5,983
Commercial customers	64,463	62,648	1,815
Industrial customers	930	919	11
Total number of customers	687,018	679,209	7,809

(1) Amounts reported as margin for each category of customer include operating revenues, which are net of revenue taxes, less cost of gas.

(2) Average weather represents the 25-year average degree days, as determined in our Oregon general rate case. For the three and nine months ended September 30, 2013 and 2012, average weather represents degree days based on the 25-year average that was set in our 2012 and 2003 Oregon general rate cases, respectively.

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Residential and Commercial Sales

Residential and commercial sales highlights include:

In thousands	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Volumes (therms):						
Residential sales	28,962	28,369	260,687	268,503	593	(7,816)
Commercial sales	25,090	25,117	165,342	168,913	(27)	(3,571)
Total volumes	54,052	53,486	426,029	437,416	566	(11,387)
Operating revenues:						
Residential sales	$41,751	$38,937	$285,661	$288,714	$2,814	$(3,053)
Commercial sales	25,833	25,183	148,444	146,126	650	2,318
Total operating revenues	$67,584	$64,120	$434,105	$434,840	$3,464	$(735)
Utility margin:						
Residential:						
Sales	$27,067	$22,681	$151,971	$145,923	$4,386	$6,048
Weather normalization adjustments	—	—	(2,731)	(2,807)	—	76
Decoupling adjustments	(29)	(10)	1,835	6,253	(19)	(4,418)
Total residential utility margin	27,038	22,671	151,075	149,369	4,367	1,706
Commercial:						
Sales	11,863	10,165	61,679	58,444	1,698	3,235
Weather normalization adjustments	—	—	(1,228)	(1,027)	—	(201)
Decoupling adjustments	1,074	318	3,155	498	756	2,657
Total commercial utility margin	12,937	10,483	63,606	57,915	2,454	5,691
Total utility margin	$39,975	$33,154	$214,681	$207,284	$6,821	$7,397

THREE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The primary factors contributing to changes in residential and commercial sales were as follows:

- sales volumes increased 1%, primarily driven by customer growth;
- operating revenues increased $3.5 million, primarily due to a 1% increase in sales volumes and gas cost savings credits from 2012 which did not reoccur in 2013, partially offset by a 15% decrease in average gas prices, which flowed through the Company's PGA rates;
- utility margin increased $6.8 million, primarily reflecting:
  - a $5.3 million increase related to timing impacts, specifically $3.0 million from higher fixed monthly charges and $2.3 million from the new decoupling baseline due to the 2012 rate case; and
  - a $1.2 million increase related to customer growth and the rate-base return on our gas reserve investment.

NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The primary factors contributing to changes in residential and commercial sales were as follows:

- sales volumes decreased 3%, primarily reflecting 5% warmer weather than last year and 2% warmer weather than average, partially offset by customer growth;
- operating revenues remained relatively flat, as decreases in sales volumes and average gas prices were offset by $36.2 million of credits from gas cost savings which were applied to customer billings in 2012; and
- utility margin increased $7.4 million, primarily reflecting:
  - a $5.1 million increase related to customer growth and the rate-base return on our gas reserve investment; and

a $3.1 million increase related to timing impacts, specifically $1.9 million from higher fixed monthly charges and $1.2 million from the new decoupling baseline due to the 2012 rate case.

Partially offsetting these increases was a $0.9 million decrease related to the general rate decrease primarily reflecting the lower Oregon Authorized ROE of 9.5%.

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Industrial Sales and Transportation

Industrial sales and transportation highlights include:

In thousands	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Volumes (therms):						
Industrial - firm sales	7,627	7,506	24,693	25,718	121	(1,025)
Industrial - firm transportation	30,481	26,952	102,690	95,539	3,529	7,151
Industrial - interruptible sales	11,618	12,081	42,130	44,001	(463)	(1,871)
Industrial - interruptible transportation	55,355	58,339	175,878	182,866	(2,984)	(6,988)
Total volumes	105,081	104,878	345,391	348,124	203	(2,733)
Utility margin:						
Industrial - firm and interruptible sales	$2,755	$2,995	$9,209	$9,712	$(240)	$(503)
Industrial - firm and interruptible transportation	3,747	3,732	11,538	11,402	15	136
Total utility margin	$6,502	$6,727	$20,747	$21,114	$(225)	$(367)

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. Total sales volumes and utility margin remained relatively flat for the third quarter of 2013 compared to 2012. Total sales volumes decreased 1% and utility margin decreased 2% for the nine months ended September 30, 2013 compared to the same period in 2012, primarily due to lower demand from customers in the pulp and paper segment. These decreases were partially offset by contributions from new customers and added load from existing customers.

Cost of Gas

Cost of gas as reported by the utility includes gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, production from gas reserves, and company gas use. The OPUC and WUTC generally require natural gas commodity costs to be billed to customers at the actual cost incurred, or expected to be incurred, by the utility. Customer rates are set each year so that if cost estimates were met we would not earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have an incentive sharing mechanism whereby we either increase or decrease margin results based on a percentage of actual gas costs as compared to embedded gas costs in the PGA. Under this provision, our net income can be affected by differences between actual and expected gas costs, which occur primarily because of market fluctuations and volatility affecting unhedged gas purchases in the PGA. In addition, we have a regulatory agreement where we earn a rate-base return on our investment in gas reserves, which is reflected in utility margin. See “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” above.

We use natural gas commodity hedge contracts (derivative instruments), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage gas price stability. Gains and losses from these financial hedge contracts are generally included in our PGA and normally do not impact net income because the hedged prices are reflected in our annual PGA rates, subject to a regulatory prudence review. However, hedge contracts entered into after the annual PGA rates are set for Oregon customers can impact net income because we would be required to share in any gains or losses as compared to the corresponding commodity prices built into rates in the PGA. In Washington, 100% of the actual gas costs, including hedge gains and losses allocated to Washington gas sales, are passed through in customer rates. See Part II, Item 7, “Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities” and “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” in our 2012 Form 10-K, and Note 12 in this report.

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Cost of gas highlights include:

In thousands, except as noted	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Total volumes sold and delivered (therms)	159,133	158,364	771,420	785,540	769	(14,120)
Cost of gas	$33,655	$37,570	$235,156	$241,823	$(3,915)	$(6,667)
Average cost of gas (cents per therm)(1)	0.46	0.54	0.48	0.55	(0.08)	(0.07)
Utility margin gain from gas cost incentive sharing	92	467	221	3,556	(375)	(3,335)

(1) This calculation does not include volumes or amounts related to transportation only customers.

THREE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The 10% decrease in cost of gas was primarily due to a 15% decrease in average cost of gas collected through rates, reflecting lower market prices for natural gas, which are passed on to customers through PGA rate changes on November 1 each year.

The effect on net income from our gas cost incentive sharing mechanism was a pre-tax margin gain of $0.1 million for the third quarter of 2013, compared to $0.5 million for the same period in 2012.

NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The primary factors contributing to the $6.7 million decrease in cost of gas were as follows:

- a $37.7 million decrease from gas cost savings applied to customer billings in 2012. Excluding the prior year customer credits, cost of gas decreased $44.4 million or 16%, partially reflecting a 2% decrease in total sales volumes due to 5% warmer weather than last year and 2% warmer weather than average, as well as lower average gas prices in the current year's PGA; and
- average cost of gas collected through rates, excluding prior year customer refunds for gas cost savings, decreased 13%, primarily reflecting lower market prices for natural gas, which are passed on to customers through PGA rate changes on November 1 each year.

The effect on net income from our gas cost incentive sharing mechanism was a pre-tax margin gain of $0.2 million for the nine months ended September 30, 2013, compared to $3.6 million for the same period in 2012. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" above.

Business Segments - Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility in Oregon and our 75% ownership interest in the Gill Ranch underground storage facility in California. We also contract with an independent energy marketing company to provide asset management services using our utility and non-utility storage and transportation capacity, the results of which are included in this segment.

Gas storage segment highlights include:

In thousands, except per share data and as otherwise noted	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Gas storage net income	$1,407	$1,255	$4,495	$3,185	$152	$1,310
EPS - gas storage segment	0.05	0.05	0.17	0.12	—	0.05
Average gas storage contracted capacity (Bcf)	21	21	21	20	—	1

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. Our gas storage segment net income remained relatively flat for the third quarter of 2013 compared to 2012. Net income increased for the nine months ended September 30, 2013, compared to the same period in 2012, primarily due to

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higher revenues from third party asset management services, as well as lower power costs and property taxes at Gill Ranch.

For the 2013-2014 gas storage year we are fully contracted at Gill Ranch and at Mist, but market pricing for storage, particularly in California, has been negatively affected by the abundant supply of natural gas, low volatility of natural gas prices, and available gas storage capacity. We are in the process of contracting for the upcoming 2014-2015 gas storage year and anticipate lower market prices than in the previous years. See, "Financial Condition—Liquidity and Capital Resources" for more information.

Business Segments - Other
Our other business segment primarily consists of NNG Financial's equity investment in KB Pipeline, an equity investment in PGH, which in turn has invested in a cross-Cascades pipeline project, and other miscellaneous non-utility investments and business activities. Our other business segment remained relatively flat over the three and nine months ended September 30, 2013 compared to 2012, with net income or loss of less than $0.1 million for each period. See Note 4 and Note 11 for further details on our other business segment and our investment in PGH.

Consolidated Operations

Operations and Maintenance
Operations and maintenance highlights include:

In thousands	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Operations and maintenance	$32,636	$28,973	$99,610	$95,543	$3,663	$4,067

THREE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The increase in operations and maintenance expense was primarily due to:
- a $2.6 million increase in utility payroll expense primarily related to accrued incentive compensation, as well as an increase in field service employees; and
- a $0.9 million increase in utility expenses related to system maintenance and safety costs.

NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The increase in operations and maintenance expense was primarily due to:
- a $3.9 million increase in utility payroll expense, primarily related to accrued incentive compensation, as well as an increase in field service employees; and
- a $2.0 million increase in utility expenses related to system maintenance and safety costs.

Partially offsetting the factors above were:
- a $1.3 million decrease in utility bad debt expense. See further discussion below;
- a $0.3 million decrease in miscellaneous claim accruals; and
- a $0.2 million decrease in gas storage expenses.

The utility's bad debt expense remains well below 0.5% of operating revenues and has decreased compared to 2012. This decrease is primarily due to lower levels of delinquent account balances during the period and a continuation of lower delinquency rates resulting in an overall decrease to our allowance for uncollectible accounts. Our bad debt expense results are at historically low levels for the Company despite challenging economic conditions in recent years.

Our accounting expense for pension costs increased in 2013 largely due to lower interest rates; however, we have OPUC approval to defer certain utility pension costs in excess of what is currently recovered in customer rates. The pension cost deferral is recorded to a regulatory balancing account, which stabilizes the recognized amount of operations and maintenance expense. For the three and nine months ended September 30, 2013, we deferred pension expenses totaling $2.2 million and $6.9 million, respectively, and $2.1 million and $6.3 million for the same periods last year. See Note 7. As a result, increased pension costs had a minimal effect on operations and maintenance expense in the current periods, with the increase principally related to the cost allocation to our Washington operations, and increases in our non-qualified and other postretirement benefit expenses, which are

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not covered by the pension balancing account. For further explanation of the pension balancing account, see "Regulatory Matters—Rate Mechanisms—Pension Deferral," above.

Depreciation and Amortization

Depreciation and amortization expense highlights include:

In thousands	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Depreciation and amortization	$18,737	$18,281	$56,474	$54,330	$456	$2,144

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. Depreciation and amortization expense increased both for the three and nine months ended September 30, 2013 compared to 2012 due to a higher level of investment in utility property, plant, and equipment.

Other Income and Expense, Net

Other income and expense, net highlights include:

In thousands	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Other income and expense, net	$1,300	$1,180	$3,270	$2,272	$120	$998

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. Other income and expense, net remained relatively flat for the three months ended September 30, 2013 compared to 2012. For the nine months ended September 30, 2013, other income and expense, net increased due to higher interest income on Oregon regulatory asset balances, compared to the same period in 2012.

Interest Expense

Interest expense highlights include:

In thousands	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Interest expense	$11,347	$10,508	$33,543	$32,163	$839	$1,380

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. Interest expense increased both for the three and nine months ended September 30, 2013 compared to 2012 primarily due to additional issuances of long-term debt, which were used to pay down short-term debt balances. In addition, average interest rates on long-term debt were higher than short-term debt for 2013.

Income Tax Expense (Benefit)

Income tax expense (benefit) highlights include:

Dollars in thousands	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012	QTR Change	YTD Change
Income tax expense (benefit)	$(5,601)	$(3,245)	$21,697	$25,186	$(2,356)	$(3,489)
Effective tax rate	40.5%	23.0%	40.8%	45.1%	17.5%	(4.3)%

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. Income tax benefit increased and income tax expense decreased for the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012. This was primarily due to a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance. See Note 8 for more information on income taxes for the nine months ended September 30, 2013 and 2012, including a reconciliation between the statutory federal and state income tax rates and our effective rates.

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Other Consolidated Expenses
General taxes remained relatively flat for the three and nine months ended September 30, 2013 compared to the same periods in 2012.

FINANCIAL CONDITION

Capital Structure
One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45% to 50% common stock equity and 50% to 55% 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 of capital are also used to fund long-term debt retirements and short-term commercial paper maturities. See “Liquidity and Capital Resources” below and Note 6.

Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure was as follows:

	September 30,				December 31,	
	2013		2012		2012	
Common stock equity	45.3	%	46.6	%	45.3	%
Long-term debt	42.2		41.9		42.9	
Short-term debt, including any current maturities of long-term debt	12.5		11.5		11.8	
Total	100	%	100	%	100	%

Liquidity and Capital Resources
At September 30, 2013, we had $16.1 million of cash and cash equivalents compared to $5.7 million at September 30, 2012. We also had $4.0 million in restricted cash at Gill Ranch at both September 30, 2013 and 2012, which is being held as collateral for its long-term debt outstanding. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances and add short-term borrowing capacity. In addition, we may also pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC. Our use of retained earnings is not subject to those same restrictions.

For the utility segment, our short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, borrowings from multi-year credit facilities, cash available from surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use utility long-term debt proceeds to finance utility capital expenditures, refinance maturing debt of the utility and provide for general corporate purposes of the utility.

Market conditions have improved over the past few years as reflected by tighter credit spreads and increased access to financing for investment grade issuers. Based on our current debt ratings (see “Credit Ratings” below), we have been able to issue commercial paper and long-term debt at attractive rates and have not needed to borrow from our back-up credit facility. In the event that we are not able to issue new debt due to adverse market conditions or other reasons, we expect that our near term liquidity needs can be met using internal cash flows or, for the utility segment, drawing upon our committed credit facility. We also have a universal shelf registration filed with the SEC for the issuance of secured and unsecured debt or equity securities, subject to market conditions and certain regulatory approvals. As of September 30, 2013, we have Board authorization to issue up to $325 million of additional first mortgage bonds. We also currently have OPUC approval to issue up to $25 million of additional long-term debt for approved purposes. We plan to file an application with the OPUC by early 2014 to increase our OPUC long-term debt authorization to $325 million.

In the event that our senior unsecured long-term debt credit ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit or other form of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on September 30, 2013, we could have been required to post $4.2 million of collateral to our

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counterparties, assuming our long-term debt ratings were at non-investment grade levels, which would be a very significant change from our current ratings. See Note 12 and “Credit Ratings” below.

In July 2010, the U.S. Congress passed and President Obama signed into law the “Dodd-Frank Wall Street Reform and Consumer Protection Act” (Dodd-Frank Act or DFA). The legislation established a new statutory framework for the comprehensive regulation of financial institutions that participate in the swap market and, among other things, requires additional government regulation of derivative and over-the-counter transactions and expanded collateral requirements. The Company is not currently subject to regulation as a Swap Dealer under the DFA nor do we expect that it will be in the future based on current or as yet unfinalized rules. Further, we believe we are eligible for and have taken appropriate steps to be exempt from certain reporting obligations under the DFA. We will continue to monitor interpretations and Commodity Futures Trading Commission guidance to determine the impact, if any, on our hedging policies, procedures, results of operations, financial position, and liquidity.

Other recent developments that may have a significant impact on our liquidity and capital resources include pension contribution requirements, current tax benefits from bonus depreciation and other tax advantaged investments, environmental expenditures and insurance recoveries, and strategic growth initiatives.

Our gas storage segment’s short-term liquidity is supported by cash balances, internal cash flow from operations, external financing, and, to a certain extent, equity investments from its parent company. Gill Ranch has limited operational history, with operations commencing in October 2010. We anticipate operating cash flows to be sufficient for liquidity purposes, but the amount and timing of these cash flows from year to year are uncertain as the majority of Gill Ranch's storage contracts are short-term. The abundant supply of natural gas and low volatility of natural gas prices as well as available gas storage capacity in California could result in lower storage market prices than seen in previous years and could cause reductions in our earnings and a reduction of our estimates of future cash flows related to Gill Ranch. However, we continue to expect positive cash flows from Gill Ranch in the coming year.

In November 2011, Gill Ranch issued $40 million of senior secured debt, with a fixed interest rate on $20 million and a variable interest rate on the remaining $20 million. The average combined interest rate on the debt was 7.38% per annum through September 30, 2013. This debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural and other entities of the consolidated group. The maturity date of the debt is November 30, 2016.

Under the debt agreement, Gill Ranch is subject to certain covenants and restrictions, including but not limited to a financial covenant that requires Gill Ranch to maintain minimum adjusted EBITDA at various levels over the term of the debt. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the agreements, Gill Ranch is also subject to a debt service reserve requirement of 10% of the outstanding principal amount, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on the incurrence of additional debt. At September 30, 2013, we were in compliance with all covenants and restrictions under the debt agreements.

Based on several factors, including our current credit ratings, our commercial paper program, current cash reserves, committed credit facilities, and our expected ability to issue long-term debt in the capital markets, we believe our liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations, investing, and financing activities discussed below.

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas purchases and accounts receivable, short-term debt may also be used to temporarily fund utility 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 one or more unsecured revolving credit facilities. See "Credit Agreements" below. At September 30, 2013 and 2012, our utility had commercial paper outstanding of $141.3 million and $175.8 million, respectively. The effective interest rate on the utility's commercial paper outstanding at September 30, 2013 and 2012 was 0.3%.

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Credit Agreements

In December 2012, we entered into a new multi-year credit agreement for unsecured revolving loans totaling $300 million with a maturity date of December 20, 2017 and an available extension of commitments for two additional one-year periods, subject to lender approval. All lenders under the new agreement are major financial institutions with committed balances and investment grade credit ratings as of September 30, 2013 as follows:

In thousands	
Lender rating, by category	Loan Commitment
AA/Aa	$189,000
A/A1	111,000
BBB/Baa	—
Total	$300,000

Based on credit market conditions, it is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, including a review of capital ratios, credit default swap spreads, and credit ratings, we believe the risk of lender default is minimal.

Our credit agreement allows us to request increases in the total commitment amount, up to a maximum of $450 million. The agreement also permits the issuance of letters of credit in an aggregate amount of up to $200 million. Any principal and unpaid interest amounts owed on borrowings under the credit agreements is due and payable on or before the maturity date. There were no outstanding balances under this or our prior credit agreement at September 30, 2013 or 2012. Like the former credit agreement, the current credit agreement requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at September 30, 2013 and 2012, with consolidated indebtedness to total capitalization ratios of 54.7% and 53.4%, respectively.

The agreement also requires us to maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody's) and notify the lenders of any change in our senior unsecured debt ratings or senior secured debt ratings, as applicable, by such rating agencies. A change in our debt ratings by S&P or Moody's is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. In addition, interest rates on any loans outstanding under the credit agreements are tied to debt ratings and therefore a change in the debt rating would increase or decrease the cost of any loans under the credit agreements when ratings are changed. See "Credit Ratings" below.

Credit Ratings

Our debt credit ratings are a factor in our liquidity, affecting our access to the capital markets including the commercial paper market. Our debt credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. In February 2013, S&P upgraded our secured long-term first mortgage bond rating from A+ to AA-. This change has not materially impacted our liquidity, access to the short-term commercial paper markets, or our borrowing costs. There were no other changes in our credit ratings during 2013. Our 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.

Maturity and Redemption of Long-Term Debt

For the nine months ended September 30, 2013, there were no redemptions or maturities of long-term debt. Over the next twelve months, $50 million of FMBs with a coupon rate of 3.95% will be redeemed at maturity in July 2014, and $10 million of FMBs with a coupon rate of 8.26% will be redeemed at maturity in September 2014. See Part II, Item

7, "Financial Condition—Contractual Obligations" in our 2012 Form 10-K for long-term debt maturing over the next five years.

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Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements, and other cash and non-cash adjustments to operating results.

Operating activity highlights include:

	Nine Months Ended September 30,		
In thousands	2013	2012	Change
Cash provided by operating activities	$157,402	$178,062	$(20,660)

NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The significant factors contributing to the decrease in operating cash flow were as follows:

- a decrease of $36.5 million from changes in the accounts receivable balance, which was significantly reduced in 2012 from customer credit refunds; and
- a decrease of $9.0 million from an increase in the inventories balance, due to the purchase of new off-system gas storage.

Partially offsetting these decreases were:

- an increase of $14.6 million due to decreased contributions to qualified defined benefit pension plans as a result of lower required contribution levels under "Moving Ahead for Progress in the 21st Century Act" (MAP-21); and
- an increase of $11.2 million from changes in the deferred gas costs balance, which reflects a smaller variance between actual gas prices and embedded gas prices in the PGA for 2013 compared to 2012, as well as customer credits in 2012.

During the nine months ended September 30, 2013, we contributed $8.9 million to our utility's qualified defined benefit pension plans, which was higher than the $4.3 million in non-cash expense recognized on the income statement, compared to contributions of $23.5 million and $4.3 million in non-cash expense for the same nine month period in 2012. We expect pension contributions to exceed non-cash expense for the next few years, but contribution amounts will be less than previously anticipated due to the new federal funding requirements under MAP-21. The amount and timing of future contributions will depend on market interest rates and investment returns on the plans' assets.

Also significantly affecting cash flows over the past few years has been income tax legislation, including the American Taxpayer Relief Act of 2012 (2012 Act), which extended 50% bonus depreciation through 2013 for MACRS property with a recovery period of 20 years or less. These and other tax benefits resulted in a net operating tax loss for 2010, which was carried back to the tax year 2009 and resulted in a federal income tax refund of $22.3 million received in 2011 and an additional $2.1 million received in 2012. We generated taxable income in 2011 that was fully offset by an NOL carried forward from 2010. We continued to generate NOL carry-forwards during 2012. We estimate generating taxable income during 2013. As of September 30, 2013, we had an estimated federal income tax receivable balance of $0.9 million and an estimated NOL carry-forward balance of $72.5 million. In 2011 and 2012, Oregon conformed with federal bonus depreciation, contributing to a state NOL carryforward of $79.5 million. We anticipate being able to use the full amount of both NOL carryforward balances in future years prior to expiration. The NOLs would otherwise expire in 20 years for federal and 15 years for Oregon.

Final tangible property regulations applicable to all taxpayers were issued by the Treasury Department on September 13, 2013. These regulations are generally effective for taxable years beginning on or after January 1, 2014. Procedural guidance related to the final regulations and unit-of-property guidance applicable to natural gas distribution networks are expected to be issued by the end of the year. We will further evaluate the impact of the regulations after the guidance is issued.

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Investing Activities

Investing activity highlights include:

In thousands	Nine Months Ended September 30, 2013	2012	Change
Total cash used in investing activities	$119,368	$142,548	$(23,180)
Capital expenditures	86,287	100,880	(14,593)
Proceeds from sale of assets	(6,580)	—	(6,580)

NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The $23.2 million decrease in cash used in investing activities was primarily due to lower capital expenditures on facilities projects and proceeds received from the sale of assets. For more information on capital projects, see “Cash Flows—Investing Activities” in the 2012 Form 10-K, and for more information on utility and non-utility investment opportunities, see “Strategic Opportunities,” above.

Financing Activities

Financing activity highlights include:

In thousands	Nine Months Ended September 30, 2013	2012	Change
Total cash used in financing activities	$30,852	$35,629	$(4,777)
Change in short-term debt	48,950	(34,200)	83,150
Long-term debt issued	(50,000)	—	(50,000)
Long-term debt retired	—	40,000	(40,000)

NINE MONTHS ENDED SEPTEMBER 30, 2013 COMPARED TO SEPTEMBER 30, 2012. The decrease in cash used in financing activities was primarily due to $50 million of FMBs issued in the third quarter of 2013 and $40 million of long-term debt retired in the first quarter of 2012. These decreases were partially offset by changes in our short-term debt balances, which increased $49.0 million in the first nine months of 2013 compared to a decrease of $34.2 million for the same period in 2012. We continue to use long-term debt proceeds to finance utility capital expenditures, refinance maturing debt, and to fund other general corporate purposes.

Ratios of Earnings to Fixed Charges

For the nine and twelve months ended September 30, 2013 and the twelve months ended December 31, 2012, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission (SEC) method, were 2.52, 3.13, and 3.26, 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. The prior period amounts have been corrected for the prior period error identified in the first quarter of 2013. See Note 14 for detail on the prior period correction and Exhibit 12 for the detailed ratio calculation.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. See Part II, Item 7, “Application of Critical Accounting Policies and Estimates” in our 2012 Form 10-K. At September 30, 2013, we had a regulatory asset of $118.0 million for deferred environmental costs, which includes $53.9 million for additional costs expected to be paid in the future and $20.1 million of capitalized accrued interest. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For more detail on environmental recovery, see "Regulatory Matters—General Rate Cases—Environmental Settlement" above. For further discussion of contingent liabilities, see Note 13 and "Results of Operations—Rate Mechanisms—Environmental Costs" above.

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APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing our financial statements using 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 used different assumptions. Our most critical estimates and judgments include accounting for:

- regulatory cost recovery and amortizations;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes; and
- environmental contingencies.

There have been no material changes to the information provided in the 2012 Form 10-K with respect to the application of critical accounting policies and estimates (see Part II, Item 7, "Application of Critical Accounting Policies and Estimates," in the 2012 Form 10-K). We have filed an all-party settlement regarding our open environmental docket from the 2012 Oregon general rate case. The settlement outlines implementation issues regarding the Site Remediation and Recovery Mechanism's (SRRM) earnings test and could result in changes to our environmental cost recovery and deferrals. See "Results of Operations—Regulatory Matters—General Rate Cases—Environmental Settlement" above for more detail.

Management has discussed its current estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Within the context of our critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 2.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, commodity price and storage value risk, interest rate risk, foreign currency risk, credit risk, and weather risk. We monitor and manage these financial exposures as an integral part of our overall risk management program. No material changes have occurred related to our disclosures about market risk for the nine month period ending September 30, 2013. See Part I and Part II, Item 1A, "Risk Factors" in this report and Part II, Item 7A, "Quantitative and Qualitative Disclosures about Market Risk" in the 2012 Form 10-K for details regarding these risks.

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ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

The Company's management, together with its consolidated subsidiaries, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”)). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

The Company's management, together with its consolidated subsidiaries, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f).

There have been no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 4(b).

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 13 and those proceedings disclosed and incorporated by reference in Part I, Item 3, “Legal Proceedings” in our 2012 Form 10-K, we have only routine nonmaterial litigation in the ordinary course of business.

ITEM 1A. RISK FACTORS

There were no material changes from the risk factors discussed in Part I, Item 1A, "Risk Factors” in our 2012 Form 10-K. In addition to the other information set forth in this report, you should carefully consider those risk factors, which could materially affect our business, financial condition or results of operations.

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

The following table provides information about purchases of our equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934 during the quarter ended September 30, 2013:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs [2]
Balance forward			2,124,528	$ 16,732,648
07/01/13 - 07/31/13	—	$—	—	—
08/01/13 - 08/31/13	5,439	41.92	—	—
09/01/13 - 09/30/13	—	—	—	—
Total	5,439	$41.92	2,124,528	$ 16,732,648

(1) During the quarter ended September 30, 2013, 5,439 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended September 30, 2013, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated SOP.
(2) We have a common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2014 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended September 30, 2013, no shares of our common stock were purchased pursuant to this program. Since the program’s inception in 2000, we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately $83.3 million.

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: November 7, 2013

/s/ Brody J. Wilson
Brody J. Wilson
Principal Accounting Officer
Controller

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NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Quarterly Report on Form 10-Q
For the Quarter Ended September 30, 2013

Exhibit Number	Document
10	Form of Special Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan between the Company and an executive officer.
12	Statement re computation of ratios of earnings to fixed charges.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	The following materials from Northwest Natural Gas Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2013, formatted in Extensible Business Reporting Language (XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.