NORTHWEST NATURAL GAS CO
Form 10-Q
August 05, 2014

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 June 30, 2014

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 (State or other jurisdiction of incorporation or organization)	93-0256722 (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 [ ] Smaller Reporting Company [ ]

(Do not check if a 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 July 25, 2014, 27,179,992 shares of the registrant’s Common Stock (the only class of Common Stock) were outstanding.

NORTHWEST NATURAL GAS COMPANY
For the Quarterly Period Ended June 30, 2014

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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;
- projections and 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;
- levels and pricing of gas storage contracts and gas storage market trends;
- efficacy of system enhancements;
- outcomes and effects of potential claims, 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;
- effects of regulatory mechanisms;
- environmental, regulatory, litigation and insurance costs and recoveries; and
- effects of the new labor contract.

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 2013 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

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands, except per share data	2014	2013	2014	2013
Operating revenues	$133,169	$131,714	$426,555	$409,575
Operating expenses:				
Cost of gas	58,280	59,142	213,481	201,501
Operations and maintenance	34,731	33,217	70,117	66,974
General taxes	7,183	7,342	15,365	16,074
Depreciation and amortization	19,709	18,930	39,298	37,737
Total operating expenses	119,903	118,631	338,261	322,286
Income from operations	13,266	13,083	88,294	87,289
Other income and expense, net	262	1,450	1,645	1,970
Interest expense, net	11,677	11,069	23,219	22,196
Income before income taxes	1,851	3,464	66,720	67,063
Income tax expense	780	1,338	27,765	27,298
Net income	1,071	2,126	38,955	39,765
Other comprehensive income:				
Amortization of non-qualified employee benefit plan liability, net of taxes of $108 and $151 for the three months and $216 and $302 for the six months ended June 30, 2014 and 2013, respectively	166	232	331	465
Comprehensive income	$1,237	$2,358	$39,286	$40,230
Average common shares outstanding:				
Basic	27,139	26,958	27,116	26,943
Diluted	27,182	26,999	27,158	26,991
Earnings per share of common stock:				
Basic	$0.04	$0.08	$1.44	$1.48
Diluted	0.04	0.08	1.43	1.47
Dividends declared per share of common stock	0.460	0.455	0.920	0.910

See Notes to Unaudited Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2014	June 30, 2013	December 31, 2013
Assets:			
Current assets:			
Cash and cash equivalents	$17,240	$12,214	$9,471
Accounts receivable	38,621	39,061	81,889
Accrued unbilled revenue	14,592	14,692	61,527
Allowance for uncollectible accounts	(1,404)	(1,189)	(1,656)
Regulatory assets	38,265	25,952	22,635
Derivative instruments	11,191	623	5,311
Inventories	60,808	62,412	60,669
Gas reserves	20,373	15,324	20,646
Income taxes receivable	—	1,297	3,534
Deferred tax assets	4,915	—	45,241
Other current assets	14,518	8,781	21,181
Total current assets	219,119	179,167	330,448
Non-current assets:			
Property, plant, and equipment	2,965,226	2,833,083	2,918,739
Less: Accumulated depreciation	879,296	833,851	855,865
Total property, plant, and equipment, net	2,085,930	1,999,232	2,062,874
Gas reserves	130,280	113,762	121,998
Regulatory assets	267,248	393,652	369,603
Derivative instruments	1,202	1,054	1,880
Other investments	67,689	67,410	67,851
Restricted cash	3,000	4,000	4,000
Other non-current assets	12,646	14,312	12,257
Total non-current assets	2,567,995	2,593,422	2,640,463
Total assets	$2,787,114	$2,772,589	$2,970,911

See Notes to Unaudited Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

In thousands	June 30, 2014	June 30, 2013	December 31, 2013
Liabilities and equity:			
Current liabilities:			
Short-term debt	$74,200	$136,000	$188,200
Current maturities of long-term debt	100,000	—	60,000
Accounts payable	68,973	63,466	96,126
Taxes accrued	15,769	6,798	10,856
Interest accrued	7,053	6,404	7,103
Regulatory liabilities	26,742	16,644	28,335
Derivative instruments	1,490	9,392	1,891
Other current liabilities	34,507	34,446	40,280
Total current liabilities	328,734	273,150	432,791
Long-term debt	621,700	691,700	681,700
Deferred credits and other non-current liabilities:			
Deferred tax liabilities	489,892	469,964	532,036
Regulatory liabilities	309,327	294,202	303,485
Pension and other postretirement benefit liabilities	145,861	214,125	149,354
Derivative instruments	191	1,754	615
Other non-current liabilities	120,423	79,145	119,058
Total deferred credits and other non-current liabilities	1,065,694	1,059,190	1,104,548
Commitments and contingencies (see Note 13)	—	—	—
Equity:			
Common stock - no par value; authorized 100,000 shares; issued and outstanding 27,147, 26,972, and 27,075 at June 30, 2014 and 2013 and December 31, 2013, respectively	369,315	359,772	364,549
Retained earnings	407,698	397,603	393,681
Accumulated other comprehensive loss	(6,027)	(8,826)	(6,358)
Total equity	770,986	748,549	751,872
Total liabilities and equity	$2,787,114	$2,772,589	$2,970,911

See Notes to Unaudited Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

In thousands	Six Months Ended June 30, 2014	2013
Operating activities:		
Net income	$38,955	$39,765
Adjustments to reconcile net income to cash provided by operations:		
Depreciation and amortization	39,298	37,737
Regulatory amortization of gas reserves	8,680	4,970
Deferred tax liabilities, net	989	28,401
Non-cash expenses related to qualified defined benefit pension plans	2,540	2,773
Contributions to qualified defined benefit pension plans	(6,000)	(4,200)
Deferred environmental recoveries, net of (expenditures)	92,104	(2,989)
Other	1,010	(1,567)
Changes in assets and liabilities:		
Receivables	89,951	63,102
Inventories	(139)	5,190
Taxes accrued	8,447	(1,535)
Accounts payable	(24,472)	(22,155)
Interest accrued	(50)	451
Deferred gas costs	(18,812)	(648)
Other, net	744	10,847
Cash provided by operating activities	233,245	160,142
Investing activities:		
Capital expenditures	(52,489)	(55,055)
Utility gas reserves	(18,632)	(34,397)
Proceeds from sale of assets	—	6,580
Restricted cash	1,000	—
Other	(1,043)	1,743
Cash used in investing activities	(71,164)	(81,129)
Financing activities:		
Common stock issued, net	3,733	2,355
Long-term debt retired	(20,000)	—
Change in short-term debt	(114,000)	(54,250)
Cash dividend payments on common stock	(24,938)	(24,509)
Other	893	682
Cash used in financing activities	(154,312)	(75,722)
Increase (decrease) in cash and cash equivalents	7,769	3,291
Cash and cash equivalents, beginning of period	9,471	8,923
Cash and cash equivalents, end of period	$17,240	$12,214
Supplemental disclosure of cash flow information:		
Interest paid	$23,270	$21,746
Income taxes paid	14,945	—

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. We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from facilities located in Oregon and California. In addition, we have investments and other non-utility activities that we aggregate and report as other.

Our core utility business assets and operating activities are largely included in the parent company, NW Natural. 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, 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 businesses and other non-utility investments and business activities.

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

Information presented in these interim consolidated financial statements is unaudited, but includes all material adjustments that management considers necessary for fair presentation 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 2013 Annual Report on Form 10-K (2013 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 2013 Form 10-K. There were no material changes to those accounting policies during the six months ended June 30, 2014. The following are current updates to certain critical accounting policy estimates and new 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. These deferrals were as follows:

	Regulatory Assets		
	June 30,		December 31,
In thousands	2014	2013	2013
Current:			
Unrealized loss on derivatives[1]	$1,466	$9,392	$1,891
Gas costs	19,268	—	4,286
Other[2]	17,531	16,560	16,458
Total current	$38,265	$25,952	$22,635
Non-current:			
Unrealized loss on derivatives[1]	$191	$1,754	$615
Pension balancing[3]	28,997	20,327	25,713
Deferred income taxes	49,007	53,065	51,814
Pension and other postretirement benefit liabilities[3]	120,942	191,312	125,855
Environmental costs[4]	52,117	120,224	148,389
Gas costs	3,768	5,322	1,105
Other[2]	12,226	1,648	16,112
Total non-current	$267,248	$393,652	$369,603

	Regulatory Liabilities		
	June 30,		December 31,
In thousands	2014	2013	2013
Current:			
Gas costs	$6,423	$6,353	$7,510
Unrealized gain on derivatives[1]	11,286	547	5,290
Other[2]	9,033	9,744	15,535
Total current	$26,742	$16,644	$28,335
Non-current:			
Gas costs	$1,057	$481	$2,172
Unrealized gain on derivatives[1]	1,202	1,054	1,880
Accrued asset removal costs	303,567	289,105	296,294
Other[2]	3,501	3,562	3,139
Total non-current	$309,327	$294,202	$303,485

(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) These balances primarily consist of deferrals and amortizations under 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 for further information.

(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 cash 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. For further information on environmental matters, see Note 13.

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New Accounting Standards

Recent Accounting Pronouncements

REVENUE RECOGNITION. On May 28, 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09 accounting for revenue recognition. The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts expected to be entitled to in exchange for those goods or services. The model provides a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when (or as) each performance obligation is satisfied. The new requirements are effective beginning January 1, 2017, and an entity may elect either a full retrospective or simplified transition adoption method; early adoption is not permitted. NW Natural is currently assessing the impact of this standard on its financial statements and disclosures.

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 June 30,		Six Months Ended June 30,	
In thousands, except per share data	2014	2013	2014	2013
Net income	$1,071	$2,126	$38,955	$39,765
Average common shares outstanding - basic	27,139	26,958	27,116	26,943
Additional shares for stock-based compensation plans outstanding	43	41	42	48
Average common shares outstanding - diluted	27,182	26,999	27,158	26,991
Earnings per share of common stock - basic	$0.04	$0.08	$1.44	$1.48
Earnings per share of common stock - diluted	$0.04	$0.08	$1.43	$1.47
Additional information:				
Antidilutive shares excluded from net income per diluted common share calculation	39	43	28	28

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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 segment and other 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. Other 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 2013 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 June 30,			
In thousands	Utility	Gas Storage	Other	Total
2014				
Operating revenues	$128,075	$5,038	$56	$133,169
Depreciation and amortization	18,087	1,622	—	19,709
Income from operations	13,735	(485)	16	13,266
Net income (loss)	2,205	(1,157)	23	1,071
Capital expenditures	26,726	175	—	26,901
2013				
Operating revenues	$123,943	$7,715	$56	$131,714
Depreciation and amortization	17,311	1,619	—	18,930
Income from operations	9,437	3,625	21	13,083
Net income	657	1,452	17	2,126
Capital expenditures	32,134	247	—	32,381

	Six Months Ended June 30,			
In thousands	Utility	Gas Storage	Other	Total
2014				
Operating revenues	$413,570	$12,873	$112	$426,555
Depreciation and amortization	36,054	3,244	—	39,298
Income from operations	85,192	3,068	34	88,294
Net income	38,224	470	261	38,955
Capital expenditures	52,076	413	—	52,489
Total assets at June 30, 2014	2,487,771	282,939	16,404	2,787,114
2013				
Operating revenues	$393,602	$15,861	$112	$409,575
Depreciation and amortization	34,499	3,238	—	37,737
Income from operations	79,665	7,582	42	87,289
Net income (loss)	36,688	3,088	(11)	39,765
Capital expenditures	54,522	533	—	55,055
Total assets at June 30, 2013	2,469,320	287,341	15,928	2,772,589
Total assets at December 31, 2013	2,644,367	310,097	16,447	2,970,911

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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. The cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. By subtracting 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 June 30,		Six Months Ended June 30,	
In thousands	2014	2013	2014	2013
Utility margin calculation:				
Utility operating revenues	$128,075	$123,943	$413,570	$393,602
Less: Utility cost of gas	58,280	59,142	213,481	201,501
Utility margin	$69,795	$64,801	$200,089	$192,101

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). The Restated SOP was terminated in 2012. 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 2013 Form 10-K and the updates provided below.

Long-Term Incentive Plan

Performance-Based Stock Awards

LTIP performance shares incorporate a combination of market, performance, and service-based factors. During the first quarter of 2014, 43,625 performance-based shares were granted under the LTIP based on target-level awards with a weighted-average grant date fair value of $42.43 per share. Fair value for the market based portion of the LTIP 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	$41.78	
Performance term (in years)	3.0	
Quarterly dividends paid per share	$0.460	
Expected dividend yield	4.3	%
Dividend discount factor	0.8845	

Performance-Based Restricted Stock Units (RSUs)

During the first quarter of 2014, 31,113 performance-based RSUs were granted under the LTIP with a weighted-average grant date fair value of $42.03 per share. As of June 30, 2014, there was $2.4 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2019. Generally, 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. The fair value of the RSU is equal to the closing market price of the Company's common stock on the grant date.

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Restated Stock Option Plan

As of June 30, 2014, there was $0.1 million of unrecognized compensation cost from grants of stock options issued in prior years, which is expected to be recognized in 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 under the LTIP during the six months ended June 30, 2014.

6. DEBT

Short-Term Debt

At June 30, 2014, our short-term debt consisted of commercial paper notes payable with a maximum maturity of 39 days, an average maturity of 28 days, and an outstanding balance of $74.2 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 2013 Form 10-K for a description of the fair value hierarchy.

Current Maturities of Long-Term Debt

The utility has long-term debt due within the next 12 months totaling $100 million, consisting of $50 million of first rate mortgage bonds (FMB) with a coupon rate of 3.95% and maturity in July 2014, $10 million of FMBs with a coupon rate of 8.26% and maturity in September 2014, and $40 million of FMBs with a coupon rate of 4.70% and maturity in June 2015.

Long-Term Debt

Our utility segment has long-term debt, including current maturities of $701.7 million, consisting of FMBs at June 30, 2014, 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%.

At June 30, 2014, our gas storage segment's long-term debt consisted of $20 million of fixed-rate senior secured debt with a maturity date of November 30, 2016 and an interest rate of 7.75%. The debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural. Under Gill Ranch's amended loan agreement with Prudential, $20 million of the variable-rate debt was retired in June 2014. As part of the amended agreement, the EBITDA covenant requirement is suspended through March 31, 2015 with lower EBITDA hurdles thereafter, and the debt service reserve requirement is fixed at $3 million.

Our outstanding debt does not trade in active markets. We estimate the fair value of our debt using utility companies with similar credit ratings, terms, and remaining maturities to our debt that actively trade in public markets. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2 in our 2013 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:

	June 30,		December 31,
In thousands	2014	2013	2013
Carrying amount	$721,700	$691,700	$741,700
Estimated fair value	807,617	769,679	806,359

See Note 7 in our 2013 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 June 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2014	2013	2014	2013
Service cost	$1,918	$2,341	$136	$179
Interest cost	4,512	4,104	309	286
Expected return on plan assets	(4,886)	(4,678)	—	—
Amortization of net actuarial loss	2,580	4,421	46	169
Amortization of prior service costs	56	55	49	49
Net periodic benefit cost	4,180	6,243	540	683
Amount allocated to construction	(1,201)	(1,801)	(171)	(211)
Amount deferred to regulatory balancing account[1]	(1,123)	(2,271)	—	—
Net amount charged to expense	$1,856	$2,171	$369	$472

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
In thousands	2014	2013	2014	2013
Service cost	$3,836	$4,682	$271	$358
Interest cost	9,024	8,207	619	572
Expected return on plan assets	(9,772)	(9,356)	—	—
Amortization of net actuarial loss	5,160	8,842	92	338
Amortization of prior service costs	112	111	98	98
Net periodic benefit cost	8,360	12,486	1,080	1,366
Amount allocated to construction	(2,402)	(3,656)	(341)	(430)
Amount deferred to regulatory balancing account[1]	(2,224)	(4,620)	—	—
Net amount charged to expense	$3,734	$4,210	$739	$936

[1] The deferral of certain pension expenses above or below the amount set in rates was approved by the OPUC, 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 include accrued interest at the utility’s actual cost of long-term debt, with deferred revenue in the utility's allocated share of equity to be recognized in a future accounting period when deferred pension expense is collected.

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:

	Three Months Ended June 30,		Six Months Ended June 30,	
In thousands	2014	2013	2014	2013
Beginning balance	$(6,193)	$(9,058)	$(6,358)	$(9,291)
Amounts reclassified from AOCL:				
Amortization of prior service costs	(2)	(2)	(4)	(4)
Amortization of actuarial losses	276	385	551	771
Total reclassifications before tax	274	383	547	767
Tax expense	(108)	(151)	(216)	(302)
Total reclassifications for the period	166	232	331	465
Ending balance	$(6,027)	$(8,826)	$(6,027)	$(8,826)

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Employer Contributions to Company-Sponsored Defined Benefit Pension Plan
For the six months ended June 30, 2014, we made cash contributions totaling $6.0 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 contribute up to $15 million to the pension plan during 2014.

Multiemployer Pension Plan
In addition to the Company-sponsored defined benefit pension plan described above, the Company also participated in a multiemployer pension plan for its utility’s union employees known as the Western States Office and Professional Employees International Union Pension Fund (plan's EIN is 94-6076144) prior to December 2013; the Company withdrew from this plan in December 2013. NW Natural's vested participants will be entitled to receive all benefits accrued through the date of the withdrawal. The Company recorded a withdrawal liability of $8.3 million, which requires NW Natural to pay $0.6 million to the plan each year for the next 20 years. The cost of withdrawal liability was deferred to a regulatory account on the balance sheet, and we made our first quarterly payment in June 2014.

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). Company contributions to this plan totaled $1.9 million and $1.6 million for the six months ended June 30, 2014 and 2013, respectively.

See Note 8 in the 2013 Form 10-K for more information concerning these retirement and other postretirement benefit plans.

8. INCOME TAX

An estimate of annual income tax expense is made each interim period using estimates for annual pre-tax income, regulatory flow-through adjustments, tax credits, and other items. The estimated annual effective tax rate is applied to year-to-date, pre-tax income to determine income tax expense for the interim period consistent with the annual estimate.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
Dollars in thousands	2014	2013	2014	2013
Income tax at statutory rates (federal and state)	$728	$1,330	$26,449	$26,569
Increase (decrease):				
Differences required to be flowed-through by regulatory commissions	61	52	1,494	1,564
Other, net	(9)	(44)	(178)	(835)
Income tax expense	$780	$1,338	$27,765	$27,298
Effective income tax rate	42.1%	38.6%	41.6%	40.7%

The change in income tax expense for the three and six months ended June 30, 2014, compared to the same periods in 2013, is primarily due to a $0.6 million income tax charge related to a higher effective tax rate in Oregon, which required the revaluation of deferred tax balances in the first quarter of 2014. See Note 9 in the 2013 Form 10-K for more detail on income taxes and effective tax rates.

The Company’s examination by the Internal Revenue Service (IRS) for tax years 2009 through 2011 was completed during the first quarter of 2014. The examination did not result in a material change to the returns as originally filed or previously adjusted for net operating loss carrybacks. The 2012 tax year is subject to examination, and the 2013 and 2014 tax years are subject to review under the Compliance Assurance Process with the IRS.

9. PROPERTY, PLANT, AND EQUIPMENT

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

	June 30,		December 31,
In thousands	2014	2013	2013
Utility plant in service	$2,624,774	$2,468,853	$2,585,901
Utility construction work in progress	36,798	61,283	28,855
Less: Accumulated depreciation	847,828	807,652	827,380
Utility plant, net	1,813,744	1,722,484	1,787,376
Non-utility plant in service	297,269	296,167	297,330
Non-utility construction work in progress	6,385	6,780	6,653
Less: Accumulated depreciation	31,468	26,199	28,485
Non-utility plant, net	272,186	276,748	275,498
Total property, plant, and equipment	$2,085,930	$1,999,232	$2,062,874
Capital expenditures in accrued liabilities	$9,826	$7,374	$10,456

10. GAS RESERVES

We entered into our original agreements with Encana Oil & Gas (USA) Inc. (Encana) in 2011 to develop and produce physical gas reserves and provide long-term gas price protection for utility customers. Encana began drilling in 2011 under these agreements. Gas produced from working interests in these gas fields is sold at prevailing market prices, with revenues from such sales, less associated production costs, credited to the utility's cost of gas. The cost of gas, including a carrying cost for the net rate base investment, is part of NW Natural's annual Oregon PGA filing, which allows us to recover our costs through customer rates.

On March 28, 2014, we amended the original gas reserve agreements in order to facilitate Encana's proposed sale of its interest in the Jonah field to an affiliate of TPG Capital (TPG). Under the amendment, we ended the drilling program with Encana, but increased our assigned ownership interests in certain sections of the Jonah field and retained the right to invest in additional wells with the new owner. Our investment of $178 million under the original deal earns a rate of return and provides long-term gas price protection for our utility customers.

During the second quarter of 2014, we were notified by TPG's affiliate, Jonah Energy LLC, of investment opportunities in the sections of the Jonah field where we have ownership interests. The amended agreement allows us to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our proportionate ownership interest for each well in which we invest. At this time, we have agreed to participate in selected wells to be drilled in 2014 and may have the opportunity to participate in additional wells in future years. We are seeking regulatory approval in Oregon for these additional investments and expect to make a formal application to the OPUC in the third quarter with the resulting proceeding resolved either in late 2014 or early 2015. In addition to seeking cost recovery for additional wells already drilled, we are also seeking approval of a general framework, including an annual prudence review, to determine whether we participate in the funding of future wells on a well-by-well basis.

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Gas reserves acted to hedge the cost of gas for approximately 8% and 6% of our utility's gas supplies for the six months ended June 30, 2014 and 2013, 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:

	June 30,		December 31,
In thousands	2014	2013	2013
Gas reserves, current	$20,373	$15,324	$20,646
Gas reserves, non-current	157,535	126,215	140,573
Less: Accumulated amortization	27,255	12,453	18,575
Total gas reserves	150,653	129,086	142,644
Less: Deferred tax liabilities on gas reserves	34,828	39,963	42,117
Net investment in gas reserves	$115,825	$89,123	$100,527

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. NWN Energy, a wholly-owned subsidiary of NW Natural owns 50% of PGH, and 50% is owned by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. PGH is a development stage Variable Interest Entity, with our investment in Palomar reported under equity method accounting. We have determined that we are not the primary beneficiary of PGH’s activities, in accordance with the authoritative guidance related to consolidations, as we only have a 50% share of the entity and there are no stipulations that allow us a disproportionate influence over it. 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 both June 30, 2014 and 2013 and December 31, 2013. See Note 12 in our 2013 Form 10-K.

Other Investments

Other investments include financial investments in life insurance policies, which are accounted for at fair value. See Note 12 in the 2013 Form 10-K.

12. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to meet our utility’s natural gas sales requirements. These contracts include swaps, options, and combinations of option contracts. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange contracts. The financial derivatives used in order to meet our utility's natural gas requirements qualify for regulatory deferral accounting.

We enter into these financial derivatives, up to prescribed limits, primarily to hedge price variability related to our physical gas supply contracts as well as to hedge spot purchases of natural gas. The foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for pipeline demand charges paid in Canadian dollars.

In the normal course of business, we also enter into indexed-price physical forward natural gas commodity purchase contracts and options to meet the requirements of utility customers. These contracts qualify for regulatory deferral accounting treatment. We also enter into exchange contracts related to the asset management of our gas portfolio, some of which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement.

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Notional Amounts

The following table presents the absolute notional amounts related to open positions on our derivative instruments:

In thousands	June 30, 2014	2013	December 31, 2013
Natural gas (in therms):			
Financial	297,925	359,135	389,225
Physical	241,150	322,675	552,500
Foreign exchange	$10,844	$17,171	$15,002

Purchased Gas Adjustment

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. For the current gas year we have selected the 90% deferral option. 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 weighted-average cost of gas in the PGA filing. As of November 1, 2013, we reached our target hedge percentage of approximately 75% for the 2013-14 gas year, and these hedge prices were included in the PGA filing and qualified for regulatory deferral.

Unrealized and Realized Gain/Loss

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.

	Three months ended June 30,			
	2014		2013	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Benefit (expense) to cost of gas	$(5,379)	$454	$(16,139)	$(274)
Less:				
Amounts deferred to regulatory accounts on the balance sheet	5,223	(454)	16,069	274
Total loss in pre-tax earnings	$(156)	$—	$(70)	$—

	Six months ended June 30,			
	2014		2013	
In thousands	Natural gas commodity	Foreign currency	Natural gas commodity	Foreign currency
Benefit (expense) to cost of gas	$10,533	$179	$(8,956)	$(513)
Less:				
Amounts deferred to regulatory accounts on the balance sheet	(10,652)	(179)	9,032	513
Total gain (loss) in pre-tax earnings	$(119)	$—	$76	$—

The cost of foreign currency forward contracts and natural gas derivative contracts are recognized immediately in the cost of gas; however, costs above or below the amount embedded in the current year PGA are subject to a regulatory deferral tariff and therefore, are recorded as a regulatory asset or liability.

We realized a net gain of $4.3 million and $12.8 million for the three and six months ended June 30, 2014, compared to net gain of $1.4 million and a net loss of $4.0 million for the three and six months ended June 30, 2013, respectively, from the settlement of natural gas financial derivative contracts. Realized gains are recorded as a reduction to the cost of gas, while realized losses were recorded as increases to the cost of gas.

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Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of June 30, 2014 or 2013. 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 2013 or 2014. 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 gains of $11.3 million at June 30, 2014, we do not have any collateral demand exposure.

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our statement of financial position. The Company and its counterparties have the ability to set-off their obligations to each other under specified circumstances. Such circumstances may include: when there is a defaulting party, or in the event of a credit change due to a merger that affects either party, or any other termination event. If netted by counterparty, our derivative position would result in an asset of $11.5 million and a liability of $0.8 million as of June 30, 2014. As of June 30, 2013, our derivative position would have resulted in an asset of $0.2 million and a liability of $9.7 million.

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 2013 Form 10-K.

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 June 30, 2014. As of June 30, 2014 and 2013 and December 31, 2013, the net fair value was an asset of $10.7 million, a liability of $9.5 million, and an asset of $4.7 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 six months ended June 30, 2014 and 2013.

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.

In the 2012 Oregon general rate case, the Site Remediation Recovery Mechanism (SRRM) was approved to recover the Company's deferred environmental costs. The Commission ordered a separate docket to determine the prudence of deferred costs, the allocation of insurance proceeds, and an earnings test that would be applied to past and future deferred costs. We have an established schedule for the docket and expect a decision by the end of 2014.

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In Washington, 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 a determination is made.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Part I, Item 3. Legal Proceedings in our 2013 Form 10-K). 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. In February 2014, we settled with all defendant insurance companies in this litigation with the Company to receive additional payments aggregating approximately $102 million. As of June 30, 2014, we have received these payments, and the Court dismissed the case on July 29, 2014. The settlements are recognized in regulatory accounts with the treatment to be determined in the ongoing docket related to the SRRM.

Environmental Sites

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		
	June 30,		December 31,	June 30,		December 31,
In thousands	2014	2013	2013	2014	2013	2013
Portland Harbor site:						
Gasco/Siltronic Sediments	$799	$427	$1,278	$38,535	$38,058	$37,954
Other Portland Harbor	1,317	1,729	1,766	3,080	2,598	3,478
Gasco Uplands site	7,152	11,354	11,010	39,553	8,230	39,508
Siltronic Uplands site	884	496	763	401	392	406
Central Service Center site	70	100	85	190	338	248
Front Street site	1,115	475	1,274	107	178	122
Oregon Steel Mills	—	—	—	179	179	179
Total	$11,337	$14,581	$16,176	$82,045	$49,973	$81,895

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

	June 30,		December 31,
In thousands	2014	2013	2013
Cash paid(1)	$108,783	$83,936	$98,817
Total regulatory asset deferral(2)	52,117	120,224	148,389

(1) Includes $20.3 million reclassified to utility plant in 2013 associated with the water treatment station of which a portion was paid in 2012-2014.

(2) Includes cash paid, remaining liability, and interest, net of insurance reimbursement and amounts reclassified to utility plant for the water treatment station.

PORTLAND HARBOR SITE. The Portland Harbor is an 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 some of the 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

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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 $39.3 million to $350 million. We have recorded a liability of $39.3 million for the sediment clean-up, which reflects the low end of the EE/CA range as well as costs 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 the EPA. NW Natural also incurs costs related to natural resource damages from these sites. The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council 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; 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 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 the remediation of the uplands portion of the site which is at the low end of the range of potential liability; the high end of the range cannot be reasonably estimated at this time.

In September 2013, we completed construction of a groundwater source control system, including a water treatment station, at the Gasco site. We are working with ODEQ on monitoring the effectiveness of the system and at this time is it is unclear what, if any, additional actions ODEQ may require 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 the cost associated with the ongoing operation of the system and have recognized a liability which is at the low end of the range of potential cost. We cannot estimate the high end of the range due to the uncertainty associated with the duration of running the water treatment station, which will be highly dependent upon the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

Beginning November 1, 2013, capital asset costs of $19.0 million for the Gasco water treatment station were placed into rates with OPUC approval. During the first quarter of 2014, the OPUC deemed these costs prudent and approved the application of $2.5 million from insurance proceeds plus interest to reduce the total amount of Gasco costs to be recovered in rates beginning November 1, 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; the high end of the range could not be reasonably estimated as of June 30, 2014.

Siltronic Upland site. Siltronic is the location of a manufactured gas plant formerly owned by NW Natural. We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ.

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Central Service Center site. We are currently performing an environmental investigation of the property under the ODEQ's Independent Cleanup Pathway. This site is on ODEQ's list of sites with confirmed releases of hazardous substances, and cleanup is necessary.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. Studies for source control investigation have been presented to ODEQ and a final sampling plan required by ODEQ is currently being developed.

Oregon Steel Mills site. 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.

For a additional information regarding other commitment and contingencies, see Note 14 in our 2013 Form 10-K.

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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 six months ended June 30, 2014 and 2013. References 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 the three and six month periods are not necessarily indicative of expected fiscal year results. Therefore, this discussion should be read in conjunction with our 2013 Annual Report on Form 10-K (2013 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 segment and other 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 asset management services. Other 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 and other, see Note 4.

In addition to presenting the results of operations and earnings amounts in total, certain financial measures are expressed in cents per share, which are non-GAAP financial measures. 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 Note 3 in our 2013 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 June 30,		
In thousands, except per share data	2014	2013	Change
Consolidated net income	$1,071	$2,126	$(1,055)
Consolidated EPS	0.04	0.08	(0.04)
Utility margin	$69,795	$64,801	$4,994
Utility net income	2,205	657	1,548
Gas storage income (loss) from operations	(485)	3,625	(4,110)
Gas storage net income (loss)	(1,157)	1,452	(2,609)

THREE MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The key metrics and primary factors for the quarter were as follows:

- consolidated net income decreased $1.1 million primarily due to an increase in utility margin and net income that was more than offset by losses from gas storage operations;
- utility margin and net income increased $5.0 million and $1.5 million, respectively, primarily due to customer growth and rate-base returns on gas reserve and other investments; and
- gas storage net income decreased $2.6 million and incurred a net loss of $1.2 million primarily due to lower revenues from historically low contract prices for the new gas storage year, which began on April 1, 2014, and higher operating expenses.

We continue to make progress on several key initiatives. Highlights for the quarter included:

- the customer growth rate increased to 1.4% at June 30, 2014, compared to 1.0% at June 30, 2013;
- the receipt of additional proceeds from environmental insurance settlements, bringing total amounts received to $102 million year-to-date in 2014 and approximately $150 million cumulatively; and
- the amended gas reserves agreement was signed with Jonah Energy, LLC with additional capital expenditures expected in 2014. See Note 10 and "Financial Condition—Cash Flows—Investing Activities" for additional information.

ISSUES AND CHALLENGES

ECONOMY. The local, national, and global economies continue to show signs of improvement as evidenced by increased utility customer growth and business demand for natural gas. Our utility's customer growth rate, on a trailing 12-month basis, increased from 1.0% at June 30, 2013 to 1.4% at June 30, 2014 as NW Natural neared the 700,000 total customer mark. The unemployment rate in the Portland metropolitan region remained below 7% during the second quarter of 2014, a decline of over 1% from the same period in 2013. We believe our utility is well positioned to add customers and to serve increasing industrial demand as the economy continues to improve, regional business projects move forward, and proposed legislation favoring lower carbon emissions develop.

GAS PRICES, SUPPLIES, AND STORAGE VALUES. Our utility gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our customers and to hedge gas prices, so we can effectively manage costs, reduce price volatility, and maintain a competitive advantage. 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 more stable gas costs for customers. We typically hedge gas prices on 75% of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2013-14 gas year (November 1, 2013 – October 31, 2014) hedged at 75% of our forecasted sales volumes, including 31% in financial swap and option contracts and 44% in physical gas supplies. For further discussion see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" below.

In addition to the amount hedged for the current gas contract year, we were hedged at approximately 65% as of June 30, 2014 for the upcoming 2014-15 gas year and between 8% and 22% hedged for annual requirements for 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, and estimated gas reserve production. Also, our storage

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inventory levels may increase or decrease depending on future storage expansions, changes in storage contracts with third parties, and future storage recall by the utility pursuant to our utility's integrated resource plan.

While currently low and stable forward gas price curves 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, we re-contracted some expiring storage capacity for the 2014-15 gas storage year at lower prices due to the current market environment, which reflects historically low gas storage prices that negatively impacted our financial results. Increases in the demand for natural gas or decreases in supply can result in upward pressure on gas prices and gas price volatility, which could be expected to improve the market value for gas storage. Current storage prices remain very low relative to prior years due to the current flat forward price curve for the 2014-15 gas storage year. As a result, in the short-term we are focused on maintaining our facility, while being ready to capitalize on opportunities in the market that fit our business-risk profile.

ENVIRONMENTAL COSTS. We accrue estimates for 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 loss estimates. As a regulated utility, we have been allowed to defer certain costs pursuant to regulatory orders. In our 2012 general rate case, the Public Utility Commission of Oregon (OPUC) approved the recovery of our environmental costs for investigation and site remediation from customers subject to certain conditions as noted in "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 the annual earnings test in Oregon. Environmental cost recovery and carrying charges on amounts charged to Washington customers will be determined in a future proceeding.

CONSOLIDATED EARNINGS AND DIVIDENDS

Consolidated Earnings
Consolidated highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
In thousands, except per share data	2014	2013	2014	2013	Change	Change
Consolidated operating revenues	$133,169	$131,714	$426,555	$409,575	$1,455	$16,980
Consolidated operating expenses	119,903	118,631	338,261	322,286	1,272	15,975
Consolidated net income	1,071	2,126	38,955	39,765	(1,055)	(810)
Consolidated EPS	0.04	0.08	1.43	1.47	(0.04)	(0.04)

THREE AND SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The lower consolidated net income for both periods was due to a $2.6 million decrease in gas storage net income, which was partially offset by a $1.5 million increase in utility net income for both periods. Gas storage results were negatively impacted by lower prices for the new gas storage contracts that replaced expiring higher price contracts from a few years ago and higher operating expenses from additional repair and power costs. Meanwhile, the utility net income results improved with higher margin contributions for both the quarter and year-to-date periods, and the utility also had comparatively stable operations and maintenance expense for the quarter.

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Dividends

Dividend highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTD	YTD
Per common share	2014	2013	2014	2013	Change	Change
Dividends paid	$0.460	$0.455	$0.920	$0.910	$0.005	$0.010

The Board of Directors declared a quarterly dividend on our common stock of $0.46 per share, payable on August 15, 2014, to shareholders of record on July 31, 2014, reflecting an indicated annual dividend rate of $1.84 per share.

REGULATORY MATTERS

Regulation and Rates

UTILITY. Our utility business is subject to regulation by the OPUC, the Washington Utilities and Transportation Commission (WUTC), and Federal Energy Regulatory Commission (FERC) with respect to, among other matters, rates and terms of service. The OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility. Approximately 90% of our utility gas volumes and revenues are 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 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, commercial, and industrial 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 "Regulatory Activities" below.

GAS STORAGE. Our gas storage businesses are 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 system of accounts. The OPUC and CPUC regulate intrastate storage services, and the FERC regulates interstate storage services. The OPUC and FERC use a maximum cost of service model which allows for gas storage prices to be set at or below the cost of service as approved by each agency in the latest 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. In 2013, approximately 56% of our storage revenues were derived from operations regulated by OPUC and FERC and approximately 44% was derived from operations regulated by CPUC.

Regulatory Activities

The following list provides the status of open regulatory dockets and other regulatory activities during the second quarter of 2014:

- Site Remediation and Recovery Mechanism (SRRM) - A schedule to resolve this docket in 2014 was set earlier this year. The decision is expected to include a prudence review of deferred environmental costs, the allocation of insurance proceeds, including the proceeds from the recent insurance litigation settlements, and policy matters regarding the application of an earnings test. We anticipate an OPUC decision on this matter in 2014.
- Interstate Storage Sharing - This docket was opened to review the current revenue sharing arrangement that allocates a portion of the net revenues generated from non-utility Mist storage services and third-party asset management services to utility customers. We anticipate resolution of this docket in 2014.
- Prepaid Pension Asset - A schedule was established to resolve this docket in the first half of 2015, which is expected to include a decision by the OPUC on rate-base treatment of pensions on a general basis, not for a specific utility company. The Company has requested that the prepaid pension asset on the balance sheet be included in rate base and allowed a return on the investment.

- Integrated Resource Plan (IRP) - We expect to file our 2014 Oregon and Washington IRPs in August 2014. The IRP will include analysis of different growth scenarios and corresponding resource acquisition strategies in an effort to develop supply and demand resource requirements, consider uncertainties in the planning process and the need for flexibility to respond to changes, and establish a plan for providing reliable service at the least cost.

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- Gas Reserves Amendment - We have agreed to participate in certain additional wells in the Jonah field under the amended gas reserves agreement with Jonah Energy, LLC. We are currently seeking regulatory treatment in Oregon for these additional wells and expect to make a formal application to the OPUC in the third quarter, with the resulting proceeding resolved either in late 2014 or early 2015. In addition to seeking cost recovery for wells already drilled under the amended agreement, we are also seeking approval of a general framework, including an annual prudence review, to determine whether we participate in the funding of future wells on a well-by-well basis.
- PGA - We filed our preliminary PGA in August and plan to file our final PGA with the OPUC and WUTC during the third quarter of 2014 with rates effective November 1, 2014. Currently, gas costs are projected to increase slightly due to current prices across the nation as the industry refills storage, which is at lower levels after the past sustained cold winter, to prepare for the upcoming winter.

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 gas prices under spot purchases as well as contract supplies, gas prices hedged with financial derivatives, gas prices from the withdrawal of storage inventories, the production of gas reserves, interstate pipeline demand costs, a permanent rate adjustment for our SIP program, temporary rate adjustments, which amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

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. 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.

EARNINGS REVIEW. We are subject to an annual earnings review in Oregon to determine if the utility is earning above its authorized return on equity (ROE) threshold. If utility earnings exceed a specific ROE level, then 33% of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80% deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90% deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90% deferral option for the 2013-2014 PGA year. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For the 2013 calendar year, the ROE threshold was 10.58%, and we were not subject to a refund. For 2014, the ROE threshold is 10.66%, and we do not expect to be subject to a refund.

SYSTEM INTEGRITY PROGRAM (SIP). The OPUC has approved specific accounting treatment and cost recovery for our SIP, which is an integrated safety program that consolidates the bare steel replacement program, the transmission pipeline integrity management program, and the distribution integrity management program related to pipeline safety rules adopted by the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA). We record these costs 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 Oregon annual PGA. Our SIP costs are tracked into rates annually, with rate-base recovery after the first $4 million of capital costs with an annual cap of $12 million. Extraordinary costs above the cap may be approved by the OPUC.

During 2013, the OPUC approved a two-year extension, beginning in November 2012, of our capital expenditure tracking mechanism to recover capital costs related to SIP and authorized a total increase of $13.7 million in the cap during the extension period. Regulatory authority for the transmission pipeline integrity management program portion of the SIP expires October 31, 2014, and we intend to seek renewal. Regulatory authority for the bare steel program continues through December 2015. We plan to substantially complete our bare steel replacement by that time as we are precluded from tracking any additional bare steel replacement costs into rates after 2015.

ENVIRONMENTAL COST DEFERRAL. The OPUC has authorized the deferral of environmental costs and insurance recoveries associated with certain named sites, and the accrual of a carrying cost on amounts deferred. The deferred environmental costs, allocation of insurance proceeds, and application of an earnings test are incorporated in the SRRM open docket with the OPUC. Through a series of extensions, the authorized cost deferral

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and accrual of carrying costs was extended through January 2015. The WUTC also authorized the deferral of environmental costs, if any, that are appropriately allocated to Washington customers. See also Note 13 and "Regulatory Activities" above for information regarding SRRM.

PENSION DEFERRAL. In Oregon, we are allowed to defer annual pension expenses related to the qualified employee defined benefit pension plan. The amount deferred each period represents the difference between annual expense and the amount set in rates. Recovery of these deferred amounts is through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities based on a number of key assumptions, and our pension contributions. Pension expense deferrals were $1.1 million and $2.2 million for the three and six months ended June 30, 2014, respectively.

CUSTOMER CREDITS FOR GAS STORAGE SHARING. In the second quarter of 2014, the Company received regulatory approval to refund an interstate storage credit of $11.4 million to its Oregon utility customers in their June bills. These customer credits are part of our regulatory incentive sharing mechanism related to non-utility Mist storage services and asset management services. The OPUC approved an $8.8 million interstate storage credit to Oregon customers in June of 2013.

For a discussion of other rate mechanisms, see Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2013 Form 10-K.

RESULTS OF OPERATIONS

Business Segments - Local Gas Distribution Utility Operations

Utility margin results are primarily affected by customer growth, increased revenues from rate-base additions, 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 regulatory 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 customer bills and our utility's earnings. See "Results of Operations—Regulatory Matters—Rate Mechanisms" in our 2013 Form 10-K for more information on our decoupling and weather normalization mechanisms.

Utility segment highlights include:

In thousands, except per share data	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013	QTR Change	YTD Change
Utility net income	$2,205	$657	$38,224	$36,688	$1,548	$1,536
EPS - utility segment	$0.08	$0.02	$1.41	$1.36	$0.06	$0.05
Gas sold and delivered (therms)	208,253	212,097	614,470	612,287	(3,844)	2,183
Utility margin[(1)]	$69,795	$64,801	$200,089	$192,101	$4,994	$7,988

[(1)] See Utility Margin Table below for a reconciliation and additional detail.

THREE MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The primary factors contributing to the increase in net income were as follows:

- a $5.0 million increase in utility margin primarily due to an increase in customer growth and added rate-base returns on certain investments, including gas reserves; and
- a less than $0.1 million decrease in operations and maintenance expense due to an increase in non-payroll expense more than offset by a decrease in incentive compensation.
- Partially offsetting the above factors was a $1.5 million decrease in other income primarily due to lower interest income on regulatory deferred account balances.

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SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The primary factors contributing to the increase in net income were as follows:

- an $8.0 million increase in utility margin primarily due to:
  - a $9.5 million increase from customer growth and added rate-base returns on certain investments, including gas reserves; partially offset by
  - a $2.4 million loss from gas cost incentive sharing resulting from actual gas prices and volumes that were higher than those estimated in the PGA for the current gas year as compared to the prior year.
- Partially offsetting the above factors were:
  - a $0.6 million increase in tax expense due to a higher Oregon state income tax rate; and
  - a $1.4 million increase in operations and maintenance expense due to an adjustment in our allowance for uncollectible accounts in the first quarter of 2013, but also reflecting offsetting fluctuations from an increase in non-payroll expense and a decrease in incentive compensation.

Total utility volumes sold and delivered increased for the first six months of 2014 compared to the same period last year due to customer growth and the cold weather event in February, despite weather that was 5% warmer than average and 3% warmer than the same period in 2013.

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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 June 30, 2014	2013	Six months ended June 30, 2014	2013	Favorable/(Unfavorable) QTR	YTD
Utility volumes (therms):						
Residential and commercial sales	96,533	103,313	370,689	371,977	(6,780)	(1,288)
Industrial sales and transportation	111,720	108,784	243,781	240,310	2,936	3,471
Total utility volumes sold and delivered	208,253	212,097	614,470	612,287	(3,844)	2,183
Utility operating revenues:						
Residential and commercial sales	$113,186	$110,155	$383,188	$366,521	$3,031	$16,667
Industrial sales and transportation	16,855	15,723	38,367	34,748	1,132	3,619
Other revenues	1,166	1,242	2,643	2,771	(76)	(128)
Less: Revenue taxes	3,132	3,177	10,628	10,438	(45)	190
Total utility operating revenues	128,075	123,943	413,570	393,602	4,132	19,968
Less: Cost of gas	58,280	59,142	213,481	201,501	(862)	11,980
Utility margin	$69,795	$64,801	$200,089	$192,101	$4,994	$7,988
Utility margin:(1)						
Residential and commercial sales	$62,468	$57,343	$184,572	$174,706	$5,125	$9,866
Industrial sales and transportation	6,707	6,527	15,191	14,245	180	946
Miscellaneous revenues	1,279	1,242	2,866	2,771	37	95
Gain (loss) from gas cost incentive sharing	(430)	(413)	(2,261)	129	(17)	(2,390)
Other margin adjustments	(229)	102	(279)	250	(331)	(529)
Utility margin	$69,795	$64,801	$200,089	$192,101	$4,994	$7,988
Degree days:						
Average(2)	691	691	2,546	2,546	—	—
Actual degree days	530	591	2,420	2,495	(10)%	(3)%
Percent colder (warmer) than average weather(2)	(23)%	(14)%	(5)%	(2)%		

Customers - end of period:	As of June 30, 2014	2013	Change
Residential customers	630,868	622,534	8,334
Commercial customers	65,619	64,598	1,021
Industrial customers	935	935	—
Total number of customers	697,422	688,067	9,355

(1) Amounts reported as margin for each category of customer consist of 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 2012 Oregon general rate case.

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Residential and Commercial Sales

Residential and commercial sales highlights include:

In thousands	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013	QTR Change	YTD Change
Utility volumes (therms):						
Residential sales	56,059	61,775	229,236	231,725	(5,716)	(2,489)
Commercial sales	40,474	41,538	141,453	140,252	(1,064)	1,201
Total volumes	96,533	103,313	370,689	371,977	(6,780)	(1,288)
Utility operating revenues:						
Residential sales	$72,230	$71,742	$252,212	$243,910	$488	$8,302
Commercial sales	40,956	38,413	130,976	122,611	2,543	8,365
Total operating revenues	$113,186	$110,155	$383,188	$366,521	$3,031	$16,667
Utility margin:						
Residential:						
Sales	$39,444	$40,303	$127,952	$124,904	$(859)	$3,048
Weather normalization adjustments	1,663	929	489	(2,731)	734	3,220
Decoupling adjustments	1,542	(953)	407	1,864	2,495	(1,457)
Total residential utility margin	42,649	40,279	128,848	124,037	2,370	4,811
Commercial:						
Sales	17,359	16,169	52,307	49,816	1,190	2,491
Weather normalization adjustments	752	410	296	(1,228)	342	1,524
Decoupling adjustments	1,708	485	3,121	2,081	1,223	1,040
Total commercial utility margin	19,819	17,064	55,724	50,669	2,755	5,055
Total utility margin	$62,468	$57,343	$184,572	$174,706	$5,125	$9,866

THREE MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The primary factors contributing to changes in residential and commercial results were as follows:

- sales volumes decreased 7% primarily due to warmer weather;
- operating revenues increased 3% or $3.0 million primarily due to a 3% increase in average gas rates compared to last year; and
- utility margin increased 9% or $5.1 million primarily due to increases from customer growth, higher commercial margin, and added rate-base returns on our gas reserve and other investments.

SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The primary factors contributing to changes in residential and commercial results were as follows:

- sales volumes decreased less then 1% primarily due to overall warmer weather offset by customer growth and a record February cold weather event;
- operating revenues increased 5% or $17 million primarily due to a 5% increase in average gas rates compared to last year; and
- utility margin increased 6% or $10 million primarily due to increases from customer growth, higher commercial margin, and added rate-base returns on our gas reserve and other investments.

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Industrial Sales and Transportation

Industrial sales and transportation highlights include:

In thousands	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013	QTR Change	YTD Change
Volumes (therms):						
Industrial - firm sales	7,427	7,586	17,565	17,066	(159)	499
Industrial - firm transportation	35,666	32,456	79,826	72,209	3,210	7,617
Industrial - interruptible sales	23,264	13,443	41,683	30,512	9,821	11,171
Industrial - interruptible transportation	45,363	55,299	104,707	120,523	(9,936)	(15,816)
Total volumes	111,720	108,784	243,781	240,310	2,936	3,471
Utility margin:						
Industrial - firm and interruptible sales	$2,872	$2,770	$6,596	$6,454	$102	$142
Industrial - firm and interruptible transportation	3,835	3,757	8,595	7,791	78	804
Total utility margin	$6,707	$6,527	$15,191	$14,245	$180	$946

THREE MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. Total sales volumes increased by 3% or 3 million therms, primarily attributable to lower usage by an industrial customer a year ago due to a planned shut-down for maintenance. Comparatively, utility margin remained flat.

SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. Total sales volumes increased by 1% or 3 million therms primarily due to the increased usage from the industrial customer mentioned above. Total utility margin increased $0.9 million primarily due to increased usage and other charges resulting from the cold weather event in February 2014.

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. See “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” above. In addition to the sharing mechanism, gains and losses from hedge contracts entered into after the annual PGA rates are set for Oregon customers are also required to be shared and can impact net income, and we have a regulatory agreement where we earn a rate-base return on our investment in gas reserves, which is also reflected in utility margin. See Part II, Item 7, “Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities” and “Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” in our 2013 Form 10-K for additional information, as well as Note 12 in this report.

Cost of gas highlights include:

In thousands, except as noted	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013	QTR Change	YTD Change
Cost of gas	$58,280	$59,142	$213,481	$201,501	$(862)	$11,980
Total volumes sold and delivered (therms)	208,253	212,097	614,470	612,287	(3,844)	2,183

Average cost of gas (cents per therm)[1]	$0.49	$0.48	$0.51	$0.48	$0.01	0.03
Gain (loss) from gas cost incentive sharing	(430)	(413)	(2,261)	129	(17)	(2,390)

[1] This calculation does not include volumes or amounts related to transportation only customers.

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THREE MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30 2013. Cost of gas decreased $0.9 million primarily due to a decrease in volumes of 3.8 million therms, partially offset by a 3% increase in average cost of gas collected through rates and additional volumes from customer growth.

SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The primary factors contributing to the $12.0 million or 6% increase in cost of gas was a 5% increase in average cost of gas collected through rates and an increase in volumes of 2.2 million therms.

During the first quarter of 2014, many parts of the United States experienced record cold weather for an extended period, while the Pacific Northwest temperatures were closer to historical averages. The extreme cold weather nationally resulted in a significant withdrawal of gas from storage and higher gas prices compared to last year. One cold weather event that did impact the Pacific Northwest in early February resulted in a new Company record sendout. Consequently, the higher volumes of gas purchases and higher gas prices resulted in a margin loss of $2.3 million for the first six months of 2014 under our gas cost incentive sharing mechanism, compared to a gain of $0.1 million for the same period in 2013. 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	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	QTR Change	YTD Change
Gas storage net income (loss)	$(1,157)	$1,452	$470	$3,088	$(2,609)	$(2,618)
EPS - gas storage segment	(0.04)	0.05	0.02	0.11	(0.09)	(0.09)
Operating revenues	5,038	7,715	12,873	15,861	(2,677)	(2,988)
Operating expenses	5,523	4,090	9,805	8,279	1,433	1,526

THREE MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The primary factors contributing to the gas storage loss were:

- a $2.7 million decrease in operating revenues. During the second quarter, we re-contracted firm storage capacity at lower prices reflecting historically low gas storage prices in the market; and
- a $1.4 million increase in operating expenses primarily due to repair and power costs at our Gill Ranch facility.

SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The primary factors contributing to the decrease in gas storage net income were:

- a $3.0 million decrease in operating revenues. During the second quarter, we re-contracted firm storage capacity at lower prices reflecting historically low gas storage prices in the market; and
- a $1.5 million increase in operating expenses primarily due to repair and power costs at our Gill Ranch facility. See additional information regarding these trends below.

Over the past few years, market prices for natural gas storage, particularly in California, were negatively affected by the abundant supply of natural gas, low volatility of natural gas prices, and surplus gas storage capacity. In addition, storage prices were further impacted by extreme cold weather this past winter, which resulted in a significant decline in storage levels, a rise in current gas prices, and lower storage values due to a flatter forward price curve for the

2014-15 gas storage year. We have re-contracted some expiring storage capacity for the 2014-15 gas storage year, which began April 1, 2014, at substantially lower market prices than in previous years, which accounted for most of the decline in gas storage operating revenues this quarter.

We incurred an additional $1.3 million of repair and power costs in the second quarter and $1.8 million for the first six months of 2014 compared to 2013 at Gill Ranch. The power cost increase reflected higher injections into storage during the second quarter to replenish low storage levels following higher withdrawals this past winter. The repair cost increase reflected work at our Gill Ranch facility, which has now been in operation for three annual cycles. We intend to continue developing repair and maintenance plans for the future as well as evaluating potential

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capital improvements that may be needed to enhance the facility. See "Financial Condition—Liquidity and Capital Resources" below.

Other

Other primarily consists of NNG Financial's equity investment in KB Pipeline, an equity investment in PGH, and other miscellaneous non-utility investments and business activities. Contributions from our other businesses produced one cent per share for the six months ended June 30, 2014 compared to a small loss in 2013. Results for the three months ended June 30, 2014 compared to 2013 were flat. 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:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
In thousands	2014	2013	2014	2013	Change	Change
Operations and maintenance	$34,731	$33,217	$70,117	$66,974	$1,514	$3,143

THREE MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The increase in operations and maintenance expense was primarily due to:

- a $1.3 million increase related to repair and power costs at our Gill Ranch gas storage facility; and
- a $1.3 million increase in utility expense related to higher system maintenance and safety program costs and professional services; offset by
- a $1.4 million decrease in utility incentive compensation accruals primarily due to a reduction in bonus pay opportunities under the new labor agreement, which became effective June 1, 2014. See "Financial Condition—Contractual Obligations" for details on the new labor agreement.

SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The increase in operations and maintenance expense was primarily due to:

- a $1.8 million increase related to repair and power costs at our Gill Ranch gas storage facility;
- a $1.6 million increase in utility expense related to higher system maintenance and safety program costs and professional services; and
- a $1.2 million increase in utility bad debt expense due to lower comparable amounts in 2013 driven by a decrease in our allowance for uncollectible accounts in the first quarter of 2013 (see paragraph below for further discussion); offset by
- a $1.8 million decrease in utility incentive compensation accruals primarily due to a reduction in bonus pay opportunities under the new labor agreement, which became effective June 1, 2014. See "Financial Condition—Contractual Obligations" for details on the new labor agreement.

Delinquent account balances have remained low for the past few years despite challenging economic conditions during the recession. This sustained favorable trend resulted in a decrease to our allowance for uncollectible accounts in the first quarter of 2013. Our bad debt expense continues to remain at historically low levels for the Company. The utility's annualized bad debt expense as a percent of revenues was 0.18% for the six months ended June 30, 2014 and for several years has remained well below 0.5% of revenues.

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 six months ended June 30, 2014, we deferred pension expenses totaling $1.1 million and $2.2 million, respectively. See Note 7 and "Regulatory Matters—Rate

Mechanisms—Pension Deferral," above for further explanation of the pension balancing account.

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Interest Expense

Interest expense highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
In thousands	2014	2013	2014	2013	Change	Change
Interest expense	$11,677	$11,069	$23,219	$22,196	$608	$1,023

THREE AND SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The increase in interest expense was primarily due to an additional $50 million of utility debt issued in August 2013 with an interest rate of 3.542%.

Other Income and Expense, Net

Other income and expense, net highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
In thousands	2014	2013	2014	2013	Change	Change
Other income and expense, net	$262	$1,450	$1,645	$1,970	$(1,188)	$(325)

THREE AND SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The decrease primarily reflects lower interest on deferred assets and liability balances as a result of the recognition of insurance proceeds, which reduced our net regulatory balances during 2014.

Income Tax Expense

Income tax expense highlights include:

	Three Months Ended June 30,		Six Months Ended June 30,		QTR	YTD
In thousands	2014	2013	2014	2013	Change	Change
Income tax expense	$780	$1,338	$27,765	$27,298	$(558)	$467

THREE MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The decrease in income tax expense was due to lower pre-tax income.

SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The increase in income tax expense was due to a tax charge of $0.6 million as a result of a higher Oregon state tax rate.

Other Consolidated Expenses

General taxes remained relatively flat for the three and six months ended June 30, 2014 compared to the same periods in 2013, as expected. Depreciation expense increased 4% for the three and six months ended June 30, 2014 compared to 2013 as a result of planned capital expenditures. See "Cash Flows—Investing Activities" below for additional information.

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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 with a target utility capital structure of 50% common stock and 50% long-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 both the target capital structure and maintaining sufficient liquidity to meet operating requirements is necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure was as follows:

	June 30, 2014		2013		December 31, 2013	
Common stock equity	49.2	%	47.5	%	44.7	%
Long-term debt	39.7		43.9		40.5	
Short-term debt, including any current maturities of long-term debt	11.1		8.6		14.8	
Total	100.0	%	100.0	%	100.0	%

Liquidity and Capital Resources
At June 30, 2014, we had $17.2 million of cash and cash equivalents compared to $12.2 million at June 30, 2013. We also had $3.0 million and $4.0 million in restricted cash at Gill Ranch at June 30, 2014 and 2013, respectively, which is being held as collateral for outstanding long-term debt. See Note 6 regarding the amended debt agreement. 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, the short-term borrowing requirements typically peak during colder months when the utility borrows money to cover the lag between its natural gas purchases and customers' payments. 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 June 30, 2014, we have Board authorization to issue up to $325 million of additional first mortgage bonds (FMBs). We also currently have OPUC approval to issue up to $25 million of additional long-term debt for approved purposes.

We filed an application with the OPUC during 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. However, based upon current financial swap and option contracts outstanding, we do not have any collateral demand exposure as the Company had unrealized gains of $11.3 million at June 30, 2014. See Note 12 and “Credit Ratings” below.

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. See "Cash Flows—Operating Activities" below.

Short-term liquidity for our gas storage segment is supported by cash balances, internal cash flow from operations, external financing, and funds from its parent company. Gill Ranch has limited operational history, with operations commencing in October 2010. The abundant supply of natural gas, low volatility of natural gas prices, and available gas storage capacity in California have resulted in lower storage market prices than we have seen in previous years. As a result, we are anticipating lower estimated future earnings and cash flows for Gill Ranch. 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. We have contracted for the 2014-15 gas year at prices lower than the prior year and realized higher repairs and power costs, causing cash flows from operations in the second quarter and likely the fiscal year to be negative. While we expect short-term storage prices to be challenging, we do not anticipate material changes in our sources of short-term liquidity.

In November 2011, Gill Ranch issued $40 million of senior secured debt, with a fixed interest rate of 7.75% on $20 million and a variable interest rate on the remaining $20 million, and an original maturity date of November 30, 2016. Under the debt agreement, Gill Ranch is subject to certain covenants and restrictions. As previously reported, in April 2014 we amended the existing agreement with Prudential to retire the $20 million variable-rate outstanding debt during the second quarter of 2014 and suspend the EBITDA covenant requirement through March 31, 2015 with lower EBITDA hurdles thereafter. The amendment also fixes the debt service reserve at $3 million. Gill Ranch paid the $20 million of debt on June 6, 2014 using available cash and cash flows from operations, including cash from intercompany receivables. The remaining $20 million of outstanding 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.

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 the Company's liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations, investing, and financing activities discussed below.

Contractual Obligations

On May 22, 2014, our union employees, who are members of the Office and Professional Employees International Union (OPEIU), Local No. 11, ratified a new labor agreement (Joint Accord) that expires on November 30, 2019. The Joint Accord includes the following items: an average annualized compensation increase of 4% effective June 1, 2014, which includes a 7.9% wage increase to better reflect current market competitive wages, offset by a reduction in bonus pay opportunities for union employees; and a scheduled 3% wage increase effective December 1 each year thereafter, beginning in 2015 with the potential for up to an additional 3% per year based on wage inflation at or above 4%. The Joint Accord also maintains competitive health benefits, including a 15% to 20% premium cost sharing by employees, job flexibility, and other flexibility provisions for the Company.

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 June 30, 2014 and 2013, our utility had commercial paper outstanding of $74.2 million and $136.0 million, respectively. The effective interest rate on the utility’s commercial paper outstanding at June 30, 2014 and 2013 was 0.2% and 0.3%, respectively.

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Credit Agreements

We have a multi-year credit agreement for unsecured revolving loans totaling $300 million with an original maturity date of December 20, 2017 and an available extension of commitments for two additional one-year periods, subject to lender approval. In December 2013, we extended our commitment for an additional year to December 20, 2018. All lenders under the new agreement are major financial institutions with committed balances and investment grade credit ratings as of June 30, 2014 as follows:

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

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, the Company does not believe this risk to be imminent due to the lenders' strong investment-grade credit ratings.

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 June 30, 2014 or 2013. 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 June 30, 2014 and 2013, with consolidated indebtedness to total capitalization ratios of 50.8% and 52.5%, 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. Rather, 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 credit ratings are a factor of our liquidity, affecting our access to 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 2014, Moody's revised our ratings outlook from negative to stable. There were no changes in our credit ratings during the second quarter of 2014. 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 or reference to 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

On June 6, 2014 we retired $20 million of variable interest rate debt issued by Gill Ranch with a coupon rate of 7.00%. See "Liquidity and Capital Resources" above for further discussion. Over the next 12 months the following debt issuances are expected to be redeemed:

- $50 million of FMBs with a coupon rate of 3.95% at maturity in July 2014;
- $10 million of FMBs with a coupon rate of 8.26% at maturity in September 2014; and

- $40 million of FMBs with a coupon rate of 4.70% at maturity in June 2015.

See Part II, Item 7, "Financial Condition—Contractual Obligations" in our 2013 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:

	Six Months Ended June 30,		
In thousands	2014	2013	Change
Cash provided by operating activities	$233,245	$160,142	$73,103

SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The significant factors contributing to the increase in operating cash flow were as follows:

- an increase of $95.1 million in deferred environmental recoveries from insurance settlements totaling $102 million; partially offset by
- a decrease of $18.2 million from changes in deferred gas costs balances, which reflected higher actual gas prices than embedded prices in the PGA for the 2014 gas year.

During the six months ended June 30, 2014, we contributed $6.0 million to our utility's qualified defined benefit pension plan, which was higher than the $2.5 million in non-cash expense recognized on the income statement, compared to $4.2 million in contributions and $2.8 million in non-cash expense for the same six month period in 2013. We expect pension contributions to exceed non-cash expense for the next few years, but contribution amounts will be less in 2014 and 2015 than previously anticipated due to the new federal funding requirements under MAP-21. The amount and timing of future contributions will depend to a certain extent on market interest rates, investment returns on the plan's assets, and future federal funding requirements.

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 modified accelerated cost recovery system property with a recovery period of 20 years or less. These and other tax benefits resulted in net operating tax losses (NOLs) during 2012 and 2013, for regular tax purposes, which are carried forward and available to offset regular taxable income in 2014. As of June 30, 2014, we had an estimated federal income tax payable balance of $8.6 million. Oregon conformed to federal bonus depreciation beginning in 2011, resulting in state NOL carry-forwards as well. We anticipate fully using the NOL carry-forwards 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 is expected to be issued by the end of 2014. We will further evaluate the impact of the regulations after this guidance is issued.

Investing Activities

Investing activity highlights include:

	Six Months Ended June 30,		
In thousands	2014	2013	Change
Total cash used in investing activities	$71,164	$81,129	$(9,965)
Utility gas reserves	18,632	34,397	(15,765)
Proceeds from sale of assets	—	(6,580)	6,580

SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The decrease in cash used in investing activities was primarily due to lower investments in utility gas reserves offset by proceeds received from the sale of property in 2013 that did not recur in 2014.

Under the amended gas reserves agreement, NW Natural ended the drilling program with Encana, but increased the Company's assigned ownership interests in certain sections of the Jonah field. At this time, we have agreed to

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participate in selected wells to be drilled in 2014. We currently expect to invest an additional $8 million to $16 million in the second half of 2014, under the amended gas reserve agreement, bringing the total expected investment, including amounts invested under the original agreement, to between $27 million and $35 million for 2014. See Note 10 for additional information regarding the amended gas reserve agreement and Part II, Item 7, "Financial Condition—Cash Flows—Investing Activities" in the 2013 Form 10-K for additional information on other expected 2014 capital expenditures.

Financing Activities

Financing activity highlights include:

	Six Months Ended June 30,		
In thousands	2014	2013	Change
Total cash used in financing activities	$154,312	$75,722	$78,590
Long-term debt retired	20,000	—	20,000
Change in short-term debt	114,000	54,250	59,750

SIX MONTHS ENDED JUNE 30, 2014 COMPARED TO JUNE 30, 2013. The increase in cash used in financing activities primarily reflected the use of proceeds from our insurance settlements of $102 million reducing our short-term debt balance. In addition, Gill Ranch retired $20 million of long-term debt.

Ratios of Earnings to Fixed Charges

For the six and twelve months ended June 30, 2014 and the 12 months ended December 31, 2013, our ratios of earnings to fixed charges computed using the Securities and Exchange Commission method were 3.74, 3.10, and 3.16, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, with fixed charges consisting of interest on all indebtedness, the amortization of debt discount or premium and expense, and the estimated interest portion of rentals charged to income. See 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 2013 Form 10-K. At June 30, 2014, we had a regulatory asset of $52.1 million for deferred environmental costs, which includes $93.4 million for additional costs expected to be paid in the future and $20.8 million of capitalized accrued interest. Additionally, in 2014, a settlement was reached in our environmental insurance recovery litigation, and NW Natural received $102 million. The regulatory asset for deferred environmental costs is calculated net of insurance reimbursements. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 13 and see also "Regulatory Matters—Rate Mechanisms—Environmental Costs".

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.

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There have been no material changes to the information provided in the 2013 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 2013 Form 10-K).

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 six month period ending June 30, 2014. See Part II, Item 1A, “Risk Factors” in this report and Part II, Item 7A, “Quantitative and Qualitative Disclosures about Market Risk” in the 2013 Form 10-K for details regarding these risks.

ITEM 4. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, 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 (SEC) 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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f).

There have been no changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2014 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 2013 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 2013 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 June 30, 2014:

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
04/01/14 - 04/30/14	—	$—	—	—
05/01/14 - 05/31/14	3,346	44.34	—	—
06/01/14 - 06/30/14	—	—	—	—
Total	3,346	44.34	2,124,528	$ 16,732,648

[1] During the quarter ended June 30, 2014, 3,346 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended June 30, 2014, 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, 2015 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended June 30, 2014, 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: August 5, 2014

/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 June 30, 2014

Exhibit Number	Document
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 June 30, 2014, 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.