

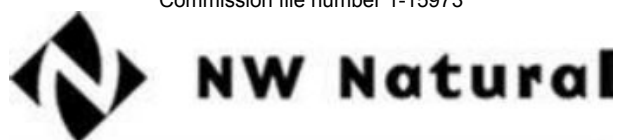
**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**  
Washington, D.C. 20549

**Form 10-Q**

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

**For the quarterly period ended March 31, 2017**

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 ☒ 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 ☒ 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," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒

Accelerated Filer ☐

Non-accelerated Filer ☐

Smaller Reporting Company ☐

(Do not check if a Smaller Reporting Company)

Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☒

At April 28, 2017, 28,644,327 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

# NORTHWEST NATURAL GAS COMPANY

For the Quarterly Period Ended March 31, 2017

## TABLE OF CONTENTS

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|                                                                                                                    | Page               |
|--------------------------------------------------------------------------------------------------------------------|--------------------|
| <b>PART 1. FINANCIAL INFORMATION</b>                                                                               |                    |
| <a href="#">Forward-Looking Statements</a>                                                                         | <a href="#">3</a>  |
| <a href="#">Item 1. Unaudited Consolidated Financial Statements:</a>                                               |                    |
| <a href="#">Consolidated Statements of Comprehensive Income for the three months ended March 31, 2017 and 2016</a> | <a href="#">5</a>  |
| <a href="#">Consolidated Balance Sheets at March 31, 2017 and 2016 and December 31, 2016</a>                       | <a href="#">6</a>  |
| <a href="#">Consolidated Statements of Cash Flows for the three months ended March 31, 2017 and 2016</a>           | <a href="#">8</a>  |
| <a href="#">Notes to Unaudited Consolidated Financial Statements</a>                                               | <a href="#">9</a>  |
| <a href="#">Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations</a>      | <a href="#">25</a> |
| <a href="#">Item 3. Quantitative and Qualitative Disclosures About Market Risk</a>                                 | <a href="#">44</a> |
| <a href="#">Item 4. Controls and Procedures</a>                                                                    | <a href="#">44</a> |
| <b>PART II. OTHER INFORMATION</b>                                                                                  |                    |
| <a href="#">Item 1. Legal Proceedings</a>                                                                          | <a href="#">45</a> |
| <a href="#">Item 1A. Risk Factors</a>                                                                              | <a href="#">45</a> |
| <a href="#">Item 2. Unregistered Sales of Equity Securities and Use of Proceeds</a>                                | <a href="#">45</a> |
| <a href="#">Item 6. Exhibits</a>                                                                                   | <a href="#">45</a> |
| <a href="#">Signature</a>                                                                                          | <a href="#">46</a> |

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## **FORWARD-LOOKING STATEMENTS**

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This report contains forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, which are subject to the safe harbors created by such Act. Forward-looking statements can be identified by words such as anticipates, assumes, 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, projections, forecasts and predictions;
- objectives, goals and strategies;
- assumptions and estimates;
- ongoing continuation of past practices or patterns;
- future events or performance;
- trends, uncertainties, timing and cyclicalities;
- risks;
- earnings and dividends;
- capital and other expenditures and allocation;
- capital or organizational structure;
- climate change and our role in a low carbon future;
- growth and profitability;
- customer rates;
- labor relations;
- workforce succession;
- commodity costs and volumes;
- gas reserves, volumes, investment and recovery;
- operational and maintenance performance and costs;
- energy policy infrastructure and preferences;
- efficacy of and exposure under derivatives and hedges;
- liquidity, funding sources, and financial positions;
- valuations;
- project and program development, expansion, or investment;
- pipeline capacity demand, location, and reliability;
- adequacy of property rights;
- procurement and development of gas supplies;
- estimated expenditures;
- competition;
- costs of compliance;
- credit exposures;
- rate or regulatory outcomes, prudence, recovery or refunds;
- impacts of, or changes in, laws, rules and regulations;
- tax positions, liabilities or refunds;
- levels and pricing of gas storage contracts and gas storage markets;
- outcomes, timing and effects of potential claims, litigation, regulatory actions, and other administrative matters;
- projected obligations, contributions, expectations and treatment under retirement plans;
- availability, adequacy, and shift in mix, of gas supplies;
- effects of new or anticipated changes in accounting standards or pronouncements;
- approval and adequacy of regulatory deferrals;
- effects and efficacy of regulatory mechanisms;
- local or national disasters, pandemic illness, terrorist activities, including cyber-attacks, explosions, or other extreme events; and
- environmental, regulatory, litigation and insurance costs, allocations and recoveries, and timing thereof.

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 operational or financial performance. Important factors that could cause actual results to differ

materially from those in the forward-looking statements are discussed in our 2016 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.

# ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

## NORTHWEST NATURAL GAS COMPANY

### CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

| <i>In thousands, except per share data</i>                                                                                                                     | Three Months Ended March 31, |            |
|----------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------|------------|
|                                                                                                                                                                | 2017                         | 2016       |
| Operating revenues                                                                                                                                             | \$ 297,323                   | \$ 255,529 |
| Operating expenses:                                                                                                                                            |                              |            |
| Cost of gas                                                                                                                                                    | 143,611                      | 108,411    |
| Operations and maintenance                                                                                                                                     | 40,420                       | 38,939     |
| Environmental remediation                                                                                                                                      | 6,954                        | 5,029      |
| General taxes                                                                                                                                                  | 9,025                        | 8,684      |
| Depreciation and amortization                                                                                                                                  | 21,085                       | 20,394     |
| Total operating expenses                                                                                                                                       | 221,095                      | 181,457    |
| Income from operations                                                                                                                                         | 76,228                       | 74,072     |
| Other income (expense), net                                                                                                                                    | 881                          | (2,309)    |
| Interest expense, net                                                                                                                                          | 9,876                        | 9,736      |
| Income before income taxes                                                                                                                                     | 67,233                       | 62,027     |
| Income tax expense                                                                                                                                             | 26,923                       | 25,386     |
| Net income                                                                                                                                                     | 40,310                       | 36,641     |
| Other comprehensive income:                                                                                                                                    |                              |            |
| Amortization of non-qualified employee benefit plan liability, net of taxes of \$89 and \$127 for the three months ended March 31, 2017 and 2016, respectively | 136                          | 194        |
| Comprehensive income                                                                                                                                           | \$ 40,446                    | \$ 36,835  |
| Average common shares outstanding:                                                                                                                             |                              |            |
| Basic                                                                                                                                                          | 28,633                       | 27,448     |
| Diluted                                                                                                                                                        | 28,723                       | 27,560     |
| Earnings per share of common stock:                                                                                                                            |                              |            |
| Basic                                                                                                                                                          | \$ 1.41                      | \$ 1.33    |
| Diluted                                                                                                                                                        | 1.40                         | 1.33       |
| Dividends declared per share of common stock                                                                                                                   | 0.4700                       | 0.4675     |

See Notes to Unaudited Consolidated Financial Statements

# NORTHWEST NATURAL GAS COMPANY

## CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| <i>In thousands</i>                              | March 31,<br>2017   | March 31,<br>2016   | December 31,<br>2016 |
|--------------------------------------------------|---------------------|---------------------|----------------------|
| <b>Assets:</b>                                   |                     |                     |                      |
| <b>Current assets:</b>                           |                     |                     |                      |
| Cash and cash equivalents                        | \$ 40,639           | \$ 4,321            | \$ 3,521             |
| Accounts receivable                              | 70,429              | 69,066              | 66,700               |
| Accrued unbilled revenue                         | 38,017              | 36,393              | 64,946               |
| Allowance for uncollectible accounts             | (1,668)             | (1,376)             | (1,290)              |
| Regulatory assets                                | 34,874              | 61,524              | 42,362               |
| Derivative instruments                           | 2,908               | 1,960               | 17,031               |
| Inventories                                      | 48,484              | 60,581              | 54,129               |
| Gas reserves                                     | 15,378              | 16,420              | 15,926               |
| Other current assets                             | 16,832              | 23,311              | 24,728               |
| <b>Total current assets</b>                      | <b>265,893</b>      | <b>272,200</b>      | <b>288,053</b>       |
| <b>Non-current assets:</b>                       |                     |                     |                      |
| Property, plant, and equipment                   | 3,247,177           | 3,115,854           | 3,208,816            |
| Less: Accumulated depreciation                   | 960,336             | 919,187             | 947,916              |
| <b>Total property, plant, and equipment, net</b> | <b>2,286,841</b>    | <b>2,196,667</b>    | <b>2,260,900</b>     |
| Gas reserves                                     | 96,630              | 111,145             | 100,184              |
| Regulatory assets                                | 349,057             | 351,390             | 357,530              |
| Derivative instruments                           | 46                  | 452                 | 3,265                |
| Other investments                                | 68,729              | 67,490              | 68,376               |
| Other non-current assets                         | 3,460               | 2,689               | 1,493                |
| <b>Total non-current assets</b>                  | <b>2,804,763</b>    | <b>2,729,833</b>    | <b>2,791,748</b>     |
| <b>Total assets</b>                              | <b>\$ 3,070,656</b> | <b>\$ 3,002,033</b> | <b>\$ 3,079,801</b>  |

See Notes to Unaudited Consolidated Financial Statements

# NORTHWEST NATURAL GAS COMPANY

## CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| <i>In thousands</i>                                                                                                                                                       | March 31,<br>2017   | March 31,<br>2016   | December 31,<br>2016 |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------|---------------------|----------------------|
| Liabilities and equity:                                                                                                                                                   |                     |                     |                      |
| Current liabilities:                                                                                                                                                      |                     |                     |                      |
| Short-term debt                                                                                                                                                           | \$ —                | \$ 164,900          | \$ 53,300            |
| Current maturities of long-term debt                                                                                                                                      | 61,994              | 24,980              | 39,989               |
| Accounts payable                                                                                                                                                          | 73,245              | 57,407              | 85,664               |
| Taxes accrued                                                                                                                                                             | 16,653              | 10,256              | 12,149               |
| Interest accrued                                                                                                                                                          | 10,581              | 9,671               | 5,966                |
| Regulatory liabilities                                                                                                                                                    | 33,211              | 35,596              | 40,290               |
| Derivative instruments                                                                                                                                                    | 1,638               | 17,313              | 1,315                |
| Other current liabilities                                                                                                                                                 | 37,697              | 42,100              | 35,844               |
| <b>Total current liabilities</b>                                                                                                                                          | <b>235,019</b>      | <b>362,223</b>      | <b>274,517</b>       |
| Long-term debt                                                                                                                                                            | 657,716             | 569,745             | 679,334              |
| Deferred credits and other non-current liabilities:                                                                                                                       |                     |                     |                      |
| Deferred tax liabilities                                                                                                                                                  | 575,451             | 550,731             | 557,085              |
| Regulatory liabilities                                                                                                                                                    | 357,587             | 346,761             | 349,319              |
| Pension and other postretirement benefit liabilities                                                                                                                      | 223,253             | 221,291             | 225,725              |
| Derivative instruments                                                                                                                                                    | 2,546               | 1,237               | 913                  |
| Other non-current liabilities                                                                                                                                             | 144,469             | 143,090             | 142,411              |
| <b>Total deferred credits and other non-current liabilities</b>                                                                                                           | <b>1,303,306</b>    | <b>1,263,110</b>    | <b>1,275,453</b>     |
| Commitments and contingencies (see Note 13)                                                                                                                               |                     |                     |                      |
| Equity:                                                                                                                                                                   |                     |                     |                      |
| Common stock - no par value; authorized 100,000 shares; issued and outstanding 28,644, 27,493, and 28,630 at March 31, 2017 and 2016, and December 31, 2016, respectively | 442,647             | 385,232             | 445,187              |
| Retained earnings                                                                                                                                                         | 438,783             | 428,691             | 412,261              |
| Accumulated other comprehensive loss                                                                                                                                      | (6,815)             | (6,968)             | (6,951)              |
| <b>Total equity</b>                                                                                                                                                       | <b>874,615</b>      | <b>806,955</b>      | <b>850,497</b>       |
| <b>Total liabilities and equity</b>                                                                                                                                       | <b>\$ 3,070,656</b> | <b>\$ 3,002,033</b> | <b>\$ 3,079,801</b>  |

See Notes to Unaudited Consolidated Financial Statements

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

Three Months Ended  
March 31,

| <i>In thousands</i>                                                 | 2017      | 2016      |
|---------------------------------------------------------------------|-----------|-----------|
| Operating activities:                                               |           |           |
| Net income                                                          | \$ 40,310 | \$ 36,641 |
| Adjustments to reconcile net income to cash provided by operations: |           |           |
| Depreciation and amortization                                       | 21,085    | 20,394    |
| Regulatory amortization of gas reserves                             | 4,107     | 4,075     |
| Deferred income taxes                                               | 20,445    | 23,353    |
| Qualified defined benefit pension plan expense                      | 1,316     | 1,311     |
| Contributions to qualified defined benefit pension plans            | (3,220)   | (2,900)   |
| Deferred environmental (expenditures) recoveries, net               | (3,432)   | (2,665)   |
| Regulatory disallowance of prior environmental cost deferrals       | —         | 3,273     |
| Amortization of environmental remediation                           | 6,954     | 5,029     |
| Other                                                               | 1,695     | 1,169     |
| Changes in assets and liabilities:                                  |           |           |
| Receivables, net                                                    | 23,147    | 22,242    |
| Inventories                                                         | 5,645     | 10,115    |
| Income taxes                                                        | 4,504     | 7,729     |
| Accounts payable                                                    | (13,437)  | (14,537)  |
| Interest accrued                                                    | 4,615     | 3,798     |
| Deferred gas costs                                                  | 13,454    | 8,519     |
| Other, net                                                          | 17,978    | 18,592    |
| Cash provided by operating activities                               | 145,166   | 146,138   |
| Investing activities:                                               |           |           |
| Capital expenditures                                                | (38,924)  | (30,054)  |
| Other                                                               | 98        | 24        |
| Cash used in investing activities                                   | (38,826)  | (30,030)  |
| Financing activities:                                               |           |           |
| Repurchases related to stock-based compensation                     | (1,943)   | (996)     |
| Proceeds from stock options exercised                               | 686       | 2,995     |
| Change in short-term debt                                           | (53,300)  | (105,135) |
| Cash dividend payments on common stock                              | (13,456)  | (12,823)  |
| Other                                                               | (1,209)   | (39)      |
| Cash used in financing activities                                   | (69,222)  | (115,998) |
| Increase in cash and cash equivalents                               | 37,118    | 110       |
| Cash and cash equivalents, beginning of period                      | 3,521     | 4,211     |
| Cash and cash equivalents, end of period                            | \$ 40,639 | \$ 4,321  |
| Supplemental disclosure of cash flow information:                   |           |           |
| Interest paid, net of capitalization                                | \$ 4,394  | \$ 5,232  |
| Income taxes paid (refunded)                                        | 3,040     | (7,900)   |

See Notes to Unaudited Consolidated Financial Statements

# **NORTHWEST NATURAL GAS COMPANY**

## **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)**

### **1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION**

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The accompanying consolidated financial statements represent the consolidated results of Northwest Natural Gas Company (NW Natural or the Company) and all companies 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 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 NWN Gas Reserves LLC (NWN Gas Reserves). Investments in corporate joint ventures and partnerships 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 Trail West Holdings, LLC (TWH) 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 financial statements are presented after elimination of all intercompany balances and transactions. 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.

Information presented in these interim consolidated financial statements is unaudited, but includes all material adjustments management considers necessary for fair statement of the results for each period reported including normal recurring accruals. These consolidated financial statements should be read in conjunction with the audited consolidated financial statements and related notes included in our 2016 Annual Report on Form 10-K (2016 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 full year results.

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

### **2. SIGNIFICANT ACCOUNTING POLICIES**

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Our significant accounting policies are described in Note 2 of the 2016 Form 10-K. There were no material changes to those accounting policies during the three months ended March 31, 2017. The following are current updates to certain critical accounting policy estimates and new accounting standards.

#### **Industry Regulation**

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the Public Utility Commission of Oregon (OPUC) or Washington Utilities and Transportation Commission (WUTC), which provide for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge in certain cases.

Amounts deferred as regulatory assets and liabilities were as follows:

| <i>In thousands</i>                                  | Regulatory Assets |                   |                   |
|------------------------------------------------------|-------------------|-------------------|-------------------|
|                                                      | March 31,         |                   | December 31,      |
|                                                      | 2017              | 2016              | 2016              |
| Current:                                             |                   |                   |                   |
| Unrealized loss on derivatives <sup>(1)</sup>        | \$ 1,580          | \$ 17,313         | \$ 1,315          |
| Gas costs                                            | 2,757             | 7,978             | 6,830             |
| Environmental costs <sup>(2)</sup>                   | 7,574             | 9,096             | 9,989             |
| Decoupling <sup>(3)</sup>                            | 10,087            | 13,235            | 13,067            |
| Other <sup>(4)</sup>                                 | 12,876            | 13,902            | 11,161            |
| Total current                                        | <u>\$ 34,874</u>  | <u>\$ 61,524</u>  | <u>\$ 42,362</u>  |
| Non-current:                                         |                   |                   |                   |
| Unrealized loss on derivatives <sup>(1)</sup>        | \$ 2,546          | \$ 1,237          | \$ 913            |
| Pension balancing <sup>(5)</sup>                     | 53,105            | 46,247            | 50,863            |
| Income taxes                                         | 36,591            | 40,106            | 38,670            |
| Pension and other postretirement benefit liabilities | 179,586           | 180,909           | 183,035           |
| Environmental costs <sup>(2)</sup>                   | 62,227            | 67,999            | 63,970            |
| Gas costs                                            | 114               | 2,462             | 89                |
| Decoupling <sup>(3)</sup>                            | 2,803             | 2,641             | 5,860             |
| Other <sup>(4)</sup>                                 | 12,085            | 9,789             | 14,130            |
| Total non-current                                    | <u>\$ 349,057</u> | <u>\$ 351,390</u> | <u>\$ 357,530</u> |

| <i>In thousands</i>                           | Regulatory Liabilities |                   |                   |
|-----------------------------------------------|------------------------|-------------------|-------------------|
|                                               | March 31,              |                   | December 31,      |
|                                               | 2017                   | 2016              | 2016              |
| Current:                                      |                        |                   |                   |
| Gas costs                                     | \$ 13,741              | \$ 22,098         | \$ 8,054          |
| Unrealized gain on derivatives <sup>(1)</sup> | 2,870                  | 1,960             | 16,624            |
| Other <sup>(4)</sup>                          | 16,600                 | 11,538            | 15,612            |
| Total current                                 | <u>\$ 33,211</u>       | <u>\$ 35,596</u>  | <u>\$ 40,290</u>  |
| Non-current:                                  |                        |                   |                   |
| Gas costs                                     | \$ 4,740               | \$ 9,221          | \$ 1,021          |
| Unrealized gain on derivatives <sup>(1)</sup> | 46                     | 452               | 3,265             |
| Accrued asset removal costs <sup>(6)</sup>    | 345,614                | 331,000           | 341,107           |
| Other <sup>(4)</sup>                          | 7,187                  | 6,088             | 3,926             |
| Total non-current                             | <u>\$ 357,587</u>      | <u>\$ 346,761</u> | <u>\$ 349,319</u> |

- <sup>(1)</sup> 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.
- <sup>(2)</sup> Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and 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. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, recovery of deferred amounts will be determined in a future proceeding. Current environmental costs represent remediation costs management expects to collect from Oregon customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the \$5 million tariff rider. The amounts allocable to Oregon are recoverable through utility rates, subject to the aforementioned earnings test. See Note 13.
- <sup>(3)</sup> This deferral represents the margin adjustment resulting from differences between actual and expected volumes.
- <sup>(4)</sup> 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.
- <sup>(5)</sup> 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 authorized rate of return, with the equity portion of interest income recognized when amounts are collected in rates.
- <sup>(6)</sup> Estimated costs of removal on certain regulated properties are collected through rates.

We believe all costs incurred and deferred at March 31, 2017 are prudent. We annually review all regulatory assets and liabilities for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write-off the net unrecoverable balances in the period such determination is made.

### **New Accounting Standards**

We consider the applicability and impact of all accounting standards updates (ASUs) issued by the Financial Accounting Standards Board (FASB). Accounting standards updates not listed below were assessed and determined to be either not applicable or are expected to have minimal impact on our consolidated financial position or results of operations.

### **Recently Adopted Accounting Pronouncements**

There were no material changes to the recently adopted accounting policies described in Note 2 of the 2016 Form 10-K during the three months ended March 31, 2017.

### **Recently Issued Accounting Pronouncements**

**RETIREMENT BENEFITS.** On March 10, 2017, the FASB issued ASU 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post Retirement Benefit Cost." The ASU requires entities to disaggregate current service cost from the other components of net periodic benefit cost and present it with other current compensation costs for related employees in the income statement and to present the other components elsewhere in the income statement and outside of income from operations if that subtotal is presented. This ASU also limits capitalization of net periodic benefit cost to the service cost component. The amendments in this update are effective for us beginning January 1, 2018. Upon adoption, the ASU requires that changes to the income statement presentation of net periodic benefit cost be applied retrospectively, while changes to amounts capitalized must be applied prospectively. We are currently assessing the effect of this standard on our financial statements and disclosures and anticipate the service cost component will be recognized in operations and maintenance expense, and the non-service cost component will be recognized in other income (expense), net. While the ASU limits capitalization of net periodic benefit cost to the service cost component, for rate making purposes, we do not expect there to be a change. As a result, we expect that the non-service cost component previously capitalized, will be reclassified to a regulatory asset. We do not anticipate any impact on net income from the adoption of this ASU.

**STATEMENT OF CASH FLOWS.** On August 26, 2016, the FASB issued ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments." The ASU adds guidance pertaining to the classification of certain cash receipts and payments on the statement of cash flows. The purpose of the amendment is to clarify issues that have been creating diversity in practice, including the classification of proceeds from the settlement of insurance claims and proceeds from the settlement of corporate-owned life insurance policies. The amendments in this standard are effective for us beginning January 1, 2018. Early adoption is permitted in any interim or annual period. We are currently assessing the effect of this standard and do not expect this standard to materially affect our financial statements and disclosures.

**LEASES.** On February 25, 2016, the FASB issued ASU 2016-02, "Leases," which revises the existing lease accounting guidance. Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases that are greater than 12 months at lease commencement, on the balance sheet and record corresponding right-of-use assets and lease liabilities. Lessor accounting will remain substantially the same under the new standard. Quantitative and qualitative disclosures are also required for users of the financial statements to have a clear understanding of the nature of our leasing activities. The standard is effective for us beginning January 1, 2019, and early adoption is permitted. The new standard must be adopted using a modified retrospective transition and provides for certain practical expedients. Transition will require application of the new guidance at the beginning of the earliest comparative period presented. We are currently assessing the effect of this standard on our financial statements and disclosures. Refer to Note 14 of the 2016 Form 10-K for our current lease commitments.

**FINANCIAL INSTRUMENTS.** On January 5, 2016, the FASB issued ASU 2016-01, "Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Financial Liabilities." The ASU enhances the reporting model for financial instruments, which includes amendments to address aspects of recognition, measurement, presentation, and disclosure. The new standard is effective for us beginning January 1, 2018. Upon adoption, we will be required

to make a cumulative-effect adjustment to the consolidated balance sheet in the first quarter of 2018. We do not expect this standard to have a material impact to our financial statements and disclosures.

**REVENUE RECOGNITION.** On May 28, 2014, the FASB issued ASU 2014-09 "Revenue From Contracts with Customers." Subsequently, the FASB issued additional, clarifying amendments to address issues and questions regarding implementation of the new revenue recognition standard. The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts the entity is expected to be entitled to in exchange for those goods or services. The ASU also prescribes a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (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 guidance also requires additional disclosures, both qualitative and quantitative, regarding the nature, amount, timing and uncertainty of revenue and cash flows. The new requirements prescribe either a full retrospective or simplified transition adoption method. We are still evaluating the overall impacts of the standard and have not yet made a determination of adoption method. Some aspects we are focused on in our review include considering the impacts this new standard will have on alternative revenue streams and how collectability will be evaluated for certain customer classes. In August 2015, the FASB deferred the effective date by one year to January 1, 2018 for annual reporting periods beginning after December 15, 2017. We plan to adopt the new standard effective January 1, 2018.

### 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 the payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented. Antidilutive stock awards are excluded from the calculation of diluted earnings per common share. Diluted earnings per share are calculated as follows:

| <i>In thousands, except per share data</i>                        | Three Months Ended March 31, |           |
|-------------------------------------------------------------------|------------------------------|-----------|
|                                                                   | 2017                         | 2016      |
| Net income                                                        | \$ 40,310                    | \$ 36,641 |
| Average common shares outstanding - basic                         | 28,633                       | 27,448    |
| Additional shares for stock-based compensation plans (See Note 5) | 90                           | 112       |
| Average common shares outstanding - diluted                       | 28,723                       | 27,560    |
| Earnings per share of common stock - basic                        | \$ 1.41                      | \$ 1.33   |
| Earnings per share of common stock - diluted                      | \$ 1.40                      | \$ 1.33   |
| Additional information:                                           |                              |           |
| Antidilutive shares                                               | 22                           | 22        |

### 4. SEGMENT INFORMATION

We primarily operate in two 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 are aggregated and reported 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 the utility portion of our Mist underground storage facility and our North Mist gas storage expansion in Oregon and NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp. 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 TWH, which is pursuing development of a cross-Cascades transmission pipeline project. See Note 4 in the 2016 Form 10-K for further discussion of our segments.

Inter-segment transactions were insignificant for the periods presented. The following table presents summary financial information concerning the reportable segments:

| <i>In thousands</i>               | Three Months Ended March 31, |             |        |            |
|-----------------------------------|------------------------------|-------------|--------|------------|
|                                   | Utility                      | Gas Storage | Other  | Total      |
| <b>2017</b>                       |                              |             |        |            |
| Operating revenues                | \$ 292,726                   | \$ 4,541    | \$ 56  | \$ 297,323 |
| Depreciation and amortization     | 19,624                       | 1,461       | —      | 21,085     |
| Income (loss) from operations     | 75,823                       | 606         | (201)  | 76,228     |
| Net income (loss)                 | 40,192                       | 61          | 57     | 40,310     |
| Capital expenditures              | 38,854                       | 70          | —      | 38,924     |
| Total assets at March 31, 2017    | 2,799,638                    | 254,260     | 16,758 | 3,070,656  |
| <b>2016</b>                       |                              |             |        |            |
| Operating revenues                | \$ 250,104                   | \$ 5,369    | \$ 56  | \$ 255,529 |
| Depreciation and amortization     | 18,760                       | 1,634       | —      | 20,394     |
| Income from operations            | 72,295                       | 1,726       | 51     | 74,072     |
| Net income                        | 35,852                       | 736         | 53     | 36,641     |
| Capital expenditures              | 29,177                       | 877         | —      | 30,054     |
| Total assets at March 31, 2016    | 2,726,696                    | 260,535     | 14,802 | 3,002,033  |
| Total assets at December 31, 2016 | 2,806,627                    | 256,333     | 16,841 | 3,079,801  |

### Utility Margin

Utility margin is a financial measure consisting of utility operating revenues, which are reduced by revenue taxes, the associated cost of gas, and environmental recovery revenues. The cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. Environmental recovery revenues represent collections received from customers through our environmental recovery mechanism in Oregon. These collections are offset by the amortization of environmental liabilities, which is presented as environmental remediation expense in our operating expenses. By subtracting cost of gas and environmental remediation expense 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 gas storage segment and other emphasize growth in operating revenues as opposed to margin because they do not incur a product cost (i.e. cost of gas sold) like the utility and, therefore, use operating revenues and net income to assess performance.

The following table presents additional segment information concerning utility margin:

| <i>In thousands</i>                       | Three Months Ended March 31, |                   |
|-------------------------------------------|------------------------------|-------------------|
|                                           | 2017                         | 2016              |
| Utility margin calculation:               |                              |                   |
| Utility operating revenues <sup>(1)</sup> | \$ 292,726                   | \$ 250,104        |
| Less: Utility cost of gas                 | 143,611                      | 108,411           |
| Environmental remediation expense         | 6,954                        | 5,029             |
| Utility margin                            | <u>\$ 142,161</u>            | <u>\$ 136,664</u> |

<sup>(1)</sup> Utility operating revenues include environmental recovery revenues, which are collections received from customers through our environmental recovery mechanism in Oregon, offset by environmental remediation expense.

## 5. STOCK-BASED COMPENSATION

Our stock-based compensation plans are designed to promote stock ownership in NW Natural by employees and officers. These compensation plans include a Long Term Incentive Plan (LTIP), an Employee Stock Purchase Plan (ESPP), and a Restated Stock Option Plan. For additional information on our stock-based compensation plans, see Note 6 in the 2016 Form 10-K and the updates provided below.

### Long Term Incentive Plan

## Performance Shares

LTIP performance shares incorporate a combination of market, performance, and service-based factors. During the three months ended March 31, 2017, 29,380 performance-based shares were granted under the LTIP based on target-level awards with a weighted-average grant date fair value of \$ 57.05 per share. Award share payouts range from a threshold of 0% to a maximum of 200% based on achievement of EPS and Return on Invested Capital (ROIC) factors, which can be modified by a total shareholder return factor (TSR factor) relative to the performance of the Russell 2500 Utilities Index over the three-year performance period and a growth modifier based on a cumulative EBITDA measure. As of March 31, 2017, there was \$ 3.1 million of unrecognized compensation cost from LTIP grants, which is expected to be recognized through 2019. Fair value for the shares granted during the three months ended March 31, 2017, 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                     | \$ | 59.90  |
| Performance term (in years)                       |    | 3.0    |
| Quarterly dividends paid per share <sup>(1)</sup> | \$ | 0.4700 |
| Expected dividend yield                           |    | 3.09%  |
| Dividend discount factor                          |    | 0.9156 |

<sup>(1)</sup>In addition to common stock shares, a participant also receives a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period.

## Restricted Stock Units

During the three months ended March 31, 2017, 18,020 RSUs were granted under the LTIP with a weighted-average grant date fair value of \$ 59.90 per share. Generally, the RSUs awarded are forfeitable and include a performance-based threshold as well as a vesting period of four years from the grant date. A RSU obligates us, 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 a RSU is equal to the closing market price of our common stock on the grant date. As of March 31, 2017, there was \$ 3.1 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2022.

## 6. DEBT

### Short-Term Debt

At March 31, 2017, we had no outstanding short-term debt.

### Long-Term Debt

At March 31, 2017, we had long-term debt of \$719.7 million, which included \$7.0 million of unamortized debt issuance costs. Utility long-term debt consists of first mortgage bonds (FMBs) with maturity dates ranging from 2017 through 2046, interest rates ranging from 1.545% to 9.05%, and a weighted-average coupon rate of 5.083%.

### Fair Value of Long-Term Debt

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 the 2016 Form 10-K for a description of the fair value hierarchy.

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:

| <i>In thousands</i>                 | March 31,  |            | December 31, |
|-------------------------------------|------------|------------|--------------|
|                                     | 2017       | 2016       | 2016         |
| Gross long-term debt                | \$ 726,700 | \$ 601,700 | \$ 726,700   |
| Unamortized debt issuance costs     | (6,990)    | (6,975)    | (7,377)      |
| Carrying amount                     | \$ 719,710 | \$ 594,725 | \$ 719,323   |
| Estimated fair value <sup>(1)</sup> | 785,980    | 686,159    | 793,339      |

<sup>(1)</sup> Estimated fair value does not include unamortized debt issuance costs.

## 7. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

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

| <i>In thousands</i>                                            | Three Months Ended March 31, |          |                               |        |
|----------------------------------------------------------------|------------------------------|----------|-------------------------------|--------|
|                                                                | Pension Benefits             |          | Other Postretirement Benefits |        |
|                                                                | 2017                         | 2016     | 2017                          | 2016   |
| Service cost                                                   | \$ 1,870                     | \$ 1,944 | \$ 98                         | \$ 121 |
| Interest cost                                                  | 4,472                        | 4,574    | 274                           | 300    |
| Expected return on plan assets                                 | (5,113)                      | (5,017)  | —                             | —      |
| Amortization of prior service costs                            | 32                           | 58       | (117)                         | (117)  |
| Amortization of net actuarial loss                             | 3,621                        | 3,502    | 138                           | 192    |
| Net periodic benefit cost                                      | 4,882                        | 5,061    | 393                           | 496    |
| Amount allocated to construction                               | (1,521)                      | (1,548)  | (132)                         | (164)  |
| Amount deferred to regulatory balancing account <sup>(1)</sup> | (1,527)                      | (1,627)  | —                             | —      |
| Net amount charged to expense                                  | \$ 1,834                     | \$ 1,886 | \$ 261                        | \$ 332 |

<sup>(1)</sup> The deferral of defined benefit pension plan 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. The balancing account includes the expectation of higher net periodic benefit costs than costs recovered in rates in the near-term with lower net periodic benefit costs than costs recovered in rates expected in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of the interest recognized when amounts are collected in rates. See Note 2 in the 2016 Form 10-K.

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:

| <i>In thousands</i>                    | Three Months Ended March 31, |            |
|----------------------------------------|------------------------------|------------|
|                                        | 2017                         | 2016       |
| Beginning balance                      | \$ (6,951)                   | \$ (7,162) |
| Amounts reclassified from AOCL:        |                              |            |
| Amortization of actuarial losses       | 225                          | 321        |
| Total reclassifications before tax     | 225                          | 321        |
| Tax (benefit) expense                  | (89)                         | (127)      |
| Total reclassifications for the period | 136                          | 194        |
| Ending balance                         | \$ (6,815)                   | \$ (6,968) |

### Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

For the three months ended March 31, 2017, we made cash contributions totaling \$3.2 million to our qualified defined benefit pension plans. We expect further plan contributions of \$16.2 million during the remainder of 2017.

### Defined Contribution Plan

The Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Sections 401(a) and 401(k). Employer contributions totaled \$1.6 million and \$1.4 million for the three months ended March 31, 2017 and 2016, respectively.

See Note 8 in the 2016 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:

| <i>Dollars in thousands</i>                                         | Three Months Ended March 31, |           |
|---------------------------------------------------------------------|------------------------------|-----------|
|                                                                     | 2017                         | 2016      |
| Income taxes at statutory rates (federal and state)                 | \$ 26,600                    | \$ 24,608 |
| Increase (decrease):                                                |                              |           |
| Differences required to be flowed-through by regulatory commissions | 1,518                        | 1,518     |
| Other, net                                                          | (1,195)                      | (740)     |
| Total provision for income taxes                                    | \$ 26,923                    | \$ 25,386 |
| Effective tax rate                                                  | 40.0%                        | 40.9%     |

The effective income tax rate for the three months ended March 31, 2017, compared to the same period in 2016, decreased primarily as a result of the equity portion of our allowance for funds used during construction (AFUDC) and increased stock-based compensation deductions in 2017. See Note 9 in the 2016 Form 10-K for more detail on income taxes and effective tax rates.

The IRS Compliance Assurance Process (CAP) examination of the 2015 tax year was completed during the quarter. There were no material changes to the return as filed. The 2016 tax year is subject to examination under CAP and the 2017 tax year CAP application has been accepted by the IRS.

## 9. PROPERTY, PLANT, AND EQUIPMENT

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

| <i>In thousands</i>                         | March 31,    |              | December 31, |
|---------------------------------------------|--------------|--------------|--------------|
|                                             | 2017         | 2016         | 2016         |
| Utility plant in service                    | \$ 2,867,271 | \$ 2,760,188 | \$ 2,843,243 |
| Utility construction work in progress       | 76,631       | 51,014       | 62,264       |
| Less: Accumulated depreciation              | 914,179      | 878,364      | 903,096      |
| Utility plant, net                          | 2,029,723    | 1,932,838    | 2,002,411    |
| Non-utility plant in service                | 299,324      | 296,826      | 299,378      |
| Non-utility construction work in progress   | 3,951        | 7,826        | 3,931        |
| Less: Accumulated depreciation              | 46,157       | 40,823       | 44,820       |
| Non-utility plant, net                      | 257,118      | 263,829      | 258,489      |
| Total property, plant, and equipment        | \$ 2,286,841 | \$ 2,196,667 | \$ 2,260,900 |
| Capital expenditures in accrued liabilities | \$ 11,564    | \$ 8,424     | \$ 9,547     |

## 10. GAS RESERVES

We have invested \$188 million through our gas reserves program in the Jonah Field located in Wyoming as of March 31, 2017. Gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the consolidated balance sheets. Our investment in gas reserves provides long-term price protection for utility customers through the original agreement with Encana Oil & Gas (USA) Inc. under which we invested \$178 million and the amended agreement with Jonah Energy LLC under which an additional \$10 million was invested.

The cost of gas, including a carrying cost for the rate base investment made under the original agreement, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our investment under the original agreement, less accumulated amortization and deferred taxes, earns a rate of return.

The volumes produced from the wells under the amended agreement with Jonah are included in our Oregon PGA at a fixed rate of \$0.4725 per therm, which approximates the 10-year hedge rate plus financing costs at the inception of the investment.

The following table outlines our net gas reserves investment:

| <i>In thousands</i>                  | March 31, |           | December 31, |
|--------------------------------------|-----------|-----------|--------------|
|                                      | 2017      | 2016      | 2016         |
| Gas reserves, current                | \$ 15,378 | \$ 16,420 | \$ 15,926    |
| Gas reserves, non-current            | 172,158   | 171,121   | 171,610      |
| Less: Accumulated amortization       | 75,528    | 59,976    | 71,426       |
| Total gas reserves <sup>(1)</sup>    | 112,008   | 127,565   | 116,110      |
| Less: Deferred taxes on gas reserves | 32,179    | 28,547    | 28,119       |
| Net investment in gas reserves       | \$ 79,829 | \$ 99,018 | \$ 87,991    |

<sup>(1)</sup> Our net investment in additional wells included in total gas reserves was \$ 6.5 million, \$ 7.6 million and \$ 6.7 million at March 31, 2017 and 2016 and December 31, 2016, respectively.

Our investment is included in our consolidated balance sheets under gas reserves with our maximum loss exposure limited to our investment balance.

## 11. INVESTMENTS

### Investments in Gas Pipeline

Trail West Pipeline, LLC (TWP), a wholly-owned subsidiary of TWH, 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 TWH, and 50% is owned by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

### Variable Interest Entity (VIE) Analysis

TWH is a VIE, with our investment in TWP reported under equity method accounting. We have determined we are not the primary beneficiary of TWH's activities as we only have a 50% share of the entity and there are no stipulations that allow us a disproportionate influence over it. Our investments in TWH and TWP are included in other investments on our balance sheet. If we do not develop this investment, then our maximum loss exposure related to TWH 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 TWH was \$13.4 million at March 31, 2017 and 2016 and December 31, 2016. See Note 12 in the 2016 Form 10-K.

### Other Investments

Other investments include financial investments in life insurance policies, which are accounted for at cash surrender value, net of policy loans. See Note 12 in the 2016 Form 10-K.

## 12. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to hedge a portion of 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.

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 third-party 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. These derivatives are recognized in operating revenues in our gas storage segment, net of amounts shared with utility customers.

### Notional Amounts

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

| <i>In thousands</i>      | March 31, |          | December 31, |
|--------------------------|-----------|----------|--------------|
|                          | 2017      | 2016     | 2016         |
| Natural gas (in therms): |           |          |              |
| Financial                | 382,850   | 317,100  | 477,430      |
| Physical                 | 368,700   | 169,978  | 535,450      |
| Foreign exchange         | \$ 6,629  | \$ 6,852 | \$ 7,497     |

### Purchased Gas Adjustment (PGA)

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years generally receive regulatory deferral accounting treatment. In general, our commodity hedging for the current gas year is completed prior to the start of the gas year, and hedge prices are reflected in our weighted-average cost of gas in the PGA filing. Hedge contracts entered into after the start of the PGA period are subject to our PGA incentive sharing mechanism in Oregon. As of November 1, 2016 and 2015, we reached our target hedge percentage of approximately 75% for the 2016-17 and 2015-16 gas years. Hedge contracts entered into prior to our PGA filing, in September 2016, were included in the PGA for the 2016-17 gas year. Hedge contracts entered into after our PGA filing, and related to subsequent gas years, may be included in future PGA filings and qualify 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:

| <i>In thousands</i>                                      | Three Months Ended March 31, |                  |                       |                  |
|----------------------------------------------------------|------------------------------|------------------|-----------------------|------------------|
|                                                          | 2017                         |                  | 2016                  |                  |
|                                                          | Natural gas commodity        | Foreign exchange | Natural gas commodity | Foreign exchange |
| Benefit (expense) to cost of gas                         | \$ (13,094)                  | \$ 26            | \$ (7,215)            | \$ 404           |
| Operating loss                                           | (1,226)                      | —                | —                     | —                |
| Amounts deferred to regulatory accounts on balance sheet | 13,893                       | (26)             | 7,215                 | (404)            |
| Total loss in pre-tax earnings                           | \$ (427)                     | \$ —             | \$ —                  | \$ —             |

**UNREALIZED GAIN/LOSS.** Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. The cost of foreign currency forward 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.

**REALIZED GAIN/LOSS.** We realized net losses of \$0.3 million and \$15.5 million for the three months ended March 31, 2017 and 2016, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts, and amortized through customer rates in the following year.

### Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of March 31, 2017 or 2016. 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 were not subject to collateral calls in 2017 or 2016. 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 commodity financial swap and option contracts outstanding, which reflect unrealized losses of \$1.4 million at March 31, 2017, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

| <i>In thousands</i>              | (Current Ratings) A+/A3 | Credit Rating Downgrade Scenarios |          |            |             |
|----------------------------------|-------------------------|-----------------------------------|----------|------------|-------------|
|                                  |                         | BBB+/Baa1                         | BBB/Baa2 | BBB-/Baa3  | Speculative |
| With Adequate Assurance Calls    | \$ —                    | \$ —                              | \$ —     | \$ (1,065) | \$ (522)    |
| Without Adequate Assurance Calls | —                       | —                                 | —        | (1,065)    | (160)       |

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our consolidated balance sheets. The Company and its counterparties have the ability to set-off their obligations to each other under specified circumstances. Such circumstances may include a defaulting party, a credit change due to a merger affecting either party, or any other termination event.

If netted by counterparty, our derivative position would result in an asset of \$1.7 million and a liability of \$2.9 million as of March 31, 2017. As of March 31, 2016, our derivative position would have resulted in an asset of \$ 1.8 million and a liability of \$ 17.9 million. As of December 31, 2016, our derivative position would have resulted in an asset of \$ 18.8 million and a liability of \$ 0.7 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 2016 Form 10-K for additional information.

## **Fair Value**

In accordance with fair value accounting, we include non-performance 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 models 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 March 31, 2017. As of March 31, 2017 and 2016, and December 31, 2016, the net fair value was a liability of \$ 1.2 million, a liability of \$ 16.1 million, and an asset \$ 18.1 million, respectively, using significant other observable, or level 2, inputs. No level 3 inputs were used in our derivative valuations, and there were no transfers between level 1 or level 2 during the three months ended March 31, 2017 and 2016. See Note 2 in the 2016 Form 10-K.

## **13. ENVIRONMENTAL MATTERS**

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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 (PRPs). When amounts are prudently expended related to site remediation, of those sites described herein, we have a recovery mechanism in place to collect 96.68% of remediation costs from Oregon customers, and we are allowed to defer environmental remediation costs allocated to customers in Washington annually until they are reviewed for prudence at a subsequent proceeding.

Our sites are subject to the remediation process prescribed by the Environmental Protection Agency (EPA) and the Oregon Department of Environmental Quality (ODEQ). The process begins with a remedial investigation (RI) to determine the nature and extent of contamination and then a risk assessment (RA) to establish whether the contamination at the site poses unacceptable risks to humans and the environment. Next, a feasibility study (FS) or an engineering evaluation/cost analysis (EE/CA) evaluates various remedial alternatives. It is at this point in the process when we are able to estimate a range of remediation costs and record a reasonable potential remediation liability, or make an adjustment to our existing liability. From this study, the regulatory agency selects a remedy and issues a Record of Decision (ROD). After a ROD is issued, we would seek to negotiate a consent decree or consent judgment for designing and implementing the remedy. We would have the ability to further refine estimates of remediation liabilities at that time.

Remediation may include treatment of contaminated media such as sediment, soil and groundwater, removal and disposal of media, institutional controls such as legal restrictions on future property use, or natural recovery. Following construction of the remedy, the EPA and ODEQ also have requirements for ongoing maintenance, monitoring and other post-remediation care that may continue for many years. Where appropriate and reasonably known, we will provide for these costs in our remediation liabilities described below.

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 where a range of potential loss is available. Unless there is an estimate within the 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 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 addition to remediation costs, we could also be subject to Natural Resource Damages (NRD) claims. We will assess the likelihood and probability of each claim and recognize a liability if deemed appropriate. We received a claim made by the Yakama Nation on January 31, 2017 for costs related to the selection of remedial action and certain declaratory relief regarding NRD. We are currently in the process of assessing the nature of, and our potential liability related to, the claim.

## Environmental Sites

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

| <i>In thousands</i>          | Current Liabilities |           |              | Non-Current Liabilities |            |              |
|------------------------------|---------------------|-----------|--------------|-------------------------|------------|--------------|
|                              | March 31,           |           | December 31, | March 31,               |            | December 31, |
|                              | 2017                | 2016      | 2016         | 2017                    | 2016       | 2016         |
| <b>Portland Harbor site:</b> |                     |           |              |                         |            |              |
| Gasco/Siltronic Sediments    | \$ 1,573            | \$ 2,747  | \$ 869       | \$ 43,200               | \$ 42,079  | \$ 43,972    |
| Other Portland Harbor        | 1,804               | 1,655     | 1,970        | 3,940                   | 4,775      | 4,148        |
| Gasco/Siltronic Upland site  | 10,335              | 10,626    | 10,657       | 50,189                  | 51,403     | 49,183       |
| Central Service Center site  | 68                  | 25        | 73           | —                       | —          | —            |
| Front Street site            | 858                 | 1,071     | 906          | 7,777                   | 7,746      | 7,786        |
| Oregon Steel Mills           | —                   | —         | —            | 179                     | 179        | 179          |
| Total                        | \$ 14,638           | \$ 16,124 | \$ 14,475    | \$ 105,285              | \$ 106,182 | \$ 105,268   |

**PORTLAND HARBOR SITE.** The Portland Harbor is an EPA listed Superfund site that is approximately 10 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands sites. We are one of over one hundred PRPs to the Superfund site. In January 2017, the EPA issued its Record of Decision, which outlines its determination of a cleanup approach for the Portland Harbor site (Portland Harbor ROD). The Portland Harbor ROD presents the EPA's decision on remedial alternatives and outlines the clean-up plan for the entire Portland Harbor. The Portland Harbor ROD estimates the present value total cost at approximately \$1.05 billion with an accuracy between -30% and +50% of actual costs.

Our potential liability is a portion of the costs of the remedy for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 PRPs. In addition, we are actively pursuing clarification and flexibility under the ROD in order to better understand our obligation under the clean-up. We are also participating in a non-binding allocation process in an effort to resolve our potential liability. The Portland Harbor ROD does not provide any additional clarification around allocation of costs among PRPs and, as a result of issuance of the Portland Harbor ROD, we have not modified any of our recorded liabilities at this time.

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. We submitted a draft 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 as well as costs for the additional studies and design work needed before the cleanup can occur, and for regulatory oversight throughout the clean-up range from \$44.8 million to \$350 million. We have recorded a liability of \$ 44.8 million for the sediment clean-up, which reflects the low end of the range. 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.** While we still believe liabilities associated with Gasco/Siltronic sediments site represent our largest exposure, we do have other potential exposures associated with the Portland Harbor ROD, including NRD costs and harbor wide clean-up costs (including downstream petroleum contamination), for which the allocations among the PRP's have not yet been determined.

The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased NRD assessment to estimate liabilities to support an early restoration-based settlement of NRD claims. One member of this Trustee council, the Yakama Nation, withdrew from the council in June 2009, and in January 2017, filed suit against the Company and 31 other parties seeking remedial costs and NRD assessment costs associated with the Portland Harbor, set forth in the complaint. The complaint

seeks recovery of alleged costs totaling \$0.3 million in connection with the selection of a remedial action for the Portland Harbor as well as declaratory judgment for unspecified future remedial action costs and for costs to assess the injury, loss or destruction of natural resources resulting from the release of hazardous substances at and from the Portland Harbor site. We have recorded 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 at this time. The NRD liability is not included in the range of costs provided in the Portland Harbor ROD.

**GASCO UPLANDS SITE.** A predecessor of NW Natural, Portland Gas and Coke Company, owned 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 (VCP). It is not included in the range of remedial costs for the Portland Harbor site noted above. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.

We submitted a revised Remedial Investigation Report for the uplands to ODEQ in May 2007. In March 2015, ODEQ approved the RA NW Natural submitted in 2010, enabling us to begin work on the FS in 2016. 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 October 2016, ODEQ and NW Natural agreed to amend their VCP agreement to incorporate a portion of the Siltronic property adjacent to the Gasco site formerly owned by Portland Gas & Coke between 1939 and 1960 into the Gasco RA and FS. Previously we were conducting an investigation of manufactured gas plant constituents on the entire Siltronic uplands for ODEQ. Siltronic will be working with ODEQ directly on environmental impacts to the remainder of its property.

In September 2013, we completed construction of a groundwater source control system, including a water treatment station, at 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 at this time due to the uncertainty associated with the duration of running the water treatment station, which is highly dependent on the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

**OTHER SITES.** In addition to those sites above, we have environmental exposures at three other sites: Central Service Center, Front Street and Oregon Steel Mills. We may have exposure at other sites that have not been identified at this time. Due to the uncertainty of the design of remediation, regulation, timing of the remediation 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 at this time.

**Central Service Center site .** We are currently performing an environmental investigation of the property under 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 (the former Portland Gas Manufacturing site, or PGM). At ODEQ's request, we conducted a sediment and source control investigation and provided findings to ODEQ. In December 2015, we completed a FS on the former Portland Gas Manufacturing site. The FS provided a range of \$7.6 million to \$12.9 million for remedial costs. We have recorded a liability at the low end of the range of possible loss as no alternative in the range is considered more likely than another. Further, we have recognized an additional liability of \$1.0 million for additional studies and design costs as well as regulatory oversight throughout the clean-up that will be required to assist in ODEQ making a remedy selection and completing a design.

**Oregon Steel Mills site .** Refer to the "Legal Proceedings," below.

### **Site Remediation and Recovery Mechanism (SRRM)**

We have a SRRM through which we track and have the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test, for those sites identified herein. In the February 2015 Order establishing the SRRM (2015 Order), the OPUC addressed outstanding issues

related to the SRRM, which required us to forego the collection of \$15 million out of approximately \$95 million in total environmental remediation expenses and associated carrying costs. As a follow-up to the 2015 Order, the OPUC issued an additional Order in January 2016 (2016 Order) regarding the SRRM implementation which resulted in a \$ 3.3 million non-cash charge primarily due to the disallowance of interest earned on the original allowance.

**COLLECTIONS FROM OREGON CUSTOMERS.** Under the SRRM collection process there are three types of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. The Company anticipates the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate.

In addition to the collection amount noted above, the Order also provides for the annual collection of \$5 million from Oregon customers through a tariff rider. As we collect amounts from customers, we recognize these collections as revenue and separately amortize an equal and offsetting amount of our deferred regulatory asset balance through the environmental remediation operating expense line shown separately in the operating expense section of the income statement.

We received total environmental insurance proceeds of approximately \$150 million as a result of settlements from our litigation that was dismissed in July 2014. Under the 2015 OPUC Order, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012 with the remaining two-thirds applied to costs at a rate of \$5 million per year plus interest over the following 20 years. We accrue interest on the insurance proceeds in the customer's favor at a rate equal to the five-year treasury rate plus 100 basis points. As of March 31, 2017, we have applied \$63.2 million of insurance proceeds to prudently incurred remediation costs.

The following table presents information regarding the total regulatory asset deferred:

| <i>In thousands</i>                            | March 31, |           | December 31, |
|------------------------------------------------|-----------|-----------|--------------|
|                                                | 2017      | 2016      | 2016         |
| Deferred costs and interest <sup>(1)</sup>     | \$ 49,373 | \$ 57,359 | \$ 53,039    |
| Accrued site liabilities <sup>(2)</sup>        | 119,623   | 122,306   | 119,443      |
| Insurance proceeds and interest                | (99,195)  | (102,570) | (98,523)     |
| Total regulatory asset deferral <sup>(1)</sup> | \$ 69,801 | \$ 77,095 | \$ 73,959    |
| Current regulatory assets <sup>(3)</sup>       | 7,574     | 9,096     | 9,989        |
| Long-term regulatory assets <sup>(3)</sup>     | 62,227    | 67,999    | 63,970       |

<sup>(1)</sup> Includes pre-review and post-review deferred costs, amounts currently in amortization, and interest, net of amounts collected from customers.

<sup>(2)</sup> Excludes \$0.3 million, or 3.32% of the Front Street site liability as the OPUC allows recovery of 96.68% of costs for those sites allocable to Oregon, including those that historically served only Oregon customers.

<sup>(3)</sup> Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and 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. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. Current environmental costs represent remediation costs management expects to collect from customers in the next 12 months. Amounts included in this estimate are still subject to a prudence and earnings test review by the OPUC and do not include the \$5 million tariff rider. The amounts allocable to Oregon are recoverable through utility rates, subject to an earnings test.

**ENVIRONMENTAL EARNINGS TEST.** To the extent the utility earns at or below its authorized Return on Equity (ROE), remediation expenses and interest in excess of the \$5 million tariff rider and \$5 million insurance proceeds are recoverable through the SRRM. To the extent the utility earns more than its authorized ROE in a year, the utility

is required to cover environmental expenses and interest on expenses greater than the \$10 million with those earnings that exceed its authorized ROE.

Under the 2015 Order, the OPUC will revisit the deferral and amortization of future remediation expenses, as well as the treatment of remaining insurance proceeds three years from the original Order, or earlier if the Company gains greater certainty about its future remediation costs, to consider whether adjustments to the mechanism may be appropriate.

**WASHINGTON DEFERRAL.** 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. Annually, we review all regulatory assets for recoverability or more often if circumstances warrant. If we should determine 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.

### **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, we do not expect that 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 Evraz 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 the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

For additional information regarding other commitments and contingencies, see Note 14 in the 2016 Form 10-K.

## 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 discussion refers to our consolidated results for the quarters ended March 31, 2017 and 2016. References in this discussion 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 month periods are not necessarily indicative of expected fiscal year results. Therefore, this discussion should be read in conjunction with our 2016 Annual Report on Form 10-K (2016 Form 10-K).

The consolidated financial statements include NW Natural and its direct and indirect wholly-owned subsidiaries including:

- 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
- NWN Gas Reserves, LLC (NWN Gas Reserves).

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 Trail West Holding, LLC (TWH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary, Trail West Pipeline, LLC (TWP), and NNG Financial's equity investment in Kelso-Beaver Pipeline (KB Pipeline). 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 or exclude the after-tax regulatory disallowance related to the OPUC's 2016 environmental order, which are non-GAAP financial measures. We present net income and earnings per share (EPS) excluding the regulatory disallowances along with the U.S. GAAP measures to illustrate the magnitude of this disallowance on ongoing business and operational results. Although the excluded amounts are properly included in the determination of net income and earnings per share under U.S. GAAP, we believe the amount and nature of such disallowances make period to period comparisons of operations difficult or potentially confusing. Financial measures are expressed in cents per share as these amounts reflect factors that directly impact earnings, including income taxes. All references in this section to EPS are on the basis of diluted shares (see Note 3). We use such non-GAAP financial measures to analyze our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

## EXECUTIVE SUMMARY

We manage our business and strategic initiatives with a long-term view of providing natural gas service safely and reliably to customers, working with regulators on key policy initiatives, and remaining focused on growing our business. See "2017 Outlook" in our 2016 Form 10-K for more information. Highlights include:

- added over 12,000 customers during the past twelve months for a growth rate of 1.7% at March 31, 2017 ;
- invested \$39 million in our distribution system and facilities for growth and reliability, including \$8 million for our North Mist gas storage expansion project; and
- received acknowledgment of our 2016 Integrated Resource Plans (IRP), which outlines long-term capital investment requirements based on projected customer growth and infrastructure needs.

Key financial highlights include:

|                                                                                             | Three Months Ended March 31, |           |            |           |          |
|---------------------------------------------------------------------------------------------|------------------------------|-----------|------------|-----------|----------|
|                                                                                             | 2017                         |           | 2016       |           | \$       |
| <i>In thousands, except per share data</i>                                                  | Amount                       | Per Share | Amount     | Per Share | Change   |
| Consolidated net income                                                                     | \$ 40,310                    | \$ 1.40   | \$ 36,641  | \$ 1.33   | \$ 3,669 |
| Adjustments:                                                                                |                              |           |            |           |          |
| Regulatory environmental disallowance, net of taxes (\$1.3 million for 2016) <sup>(1)</sup> | —                            | —         | 1,996      | 0.07      | (1,996)  |
| Adjusted consolidated net income <sup>(1)</sup>                                             | \$ 40,310                    | \$ 1.40   | \$ 38,637  | \$ 1.40   | \$ 1,673 |
| Utility margin                                                                              | \$ 142,161                   |           | \$ 136,664 |           | \$ 5,497 |
| Gas storage operating revenues                                                              | 4,541                        |           | 5,369      |           | (828)    |

<sup>(1)</sup> Regulatory environmental disallowance of \$3.3 million in 2016 includes \$2.8 million recorded in utility other income (expense), net and \$0.5 million recorded in utility operations and maintenance expense. Adjusted consolidated net income and EPS are non-GAAP financial measures based on the after-tax disallowance using the combined federal and state statutory tax rate of 39.5%. EPS is calculated using 28.7 million and 27.6 million diluted shares for three months ended March 31, 2017 and 2016, respectively.

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016** . Consolidated net income increased \$3.7 million during the three months ended March 31, 2017 primarily due to the environmental disallowance associated with a January 2016 OPUC Order in our SRRM docket described in the table above. Excluding the impact of this non-cash charge from the SRRM docket, adjusted consolidated net income increased \$1.7 million primarily due to the following factors:

- a \$5.5 million increase in utility margin primarily due to customer growth and the effects of colder than average weather in 2017 compared to a warmer than average winter in the prior period; partially offset by
- a \$2.0 million increase in operating and maintenance expense largely from payroll and benefits due to increased headcount and higher non-payroll expenses related to system integrity maintenance; and
- a \$0.8 million decrease in gas storage revenues largely due to lower revenues from our asset management agreements.

## DIVIDENDS

Dividend highlights include:

| Per common share | Three Months Ended March 31, |           |  | QTR Change |
|------------------|------------------------------|-----------|--|------------|
|                  | 2017                         | 2016      |  |            |
| Dividends paid   | \$ 0.4700                    | \$ 0.4675 |  | \$ 0.0025  |

The Board of Directors declared a quarterly dividend on our common stock of \$0.4700 cents per share, payable on May 15, 2017, to shareholders of record on April 28, 2017, reflecting an indicated annual dividend rate of \$1.88 per share.

## RESULTS OF OPERATIONS

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### Regulatory Matters

#### Regulation and Rates

**UTILITY.** Our utility business is subject to regulation by the OPUC, WUTC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility. In 2016, approximately 89 % of our utility gas customers were located in Oregon, with the remaining 11 % in Washington. Earnings and cash flows from utility operations are largely determined by rates set in general rate cases and other proceedings in Oregon and Washington. They 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 " *Most Recent General Rate Cases*" below.

**GAS STORAGE.** Our gas storage business is subject to regulation by the OPUC, WUTC, CPUC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and CPUC also regulate the issuance of securities, system of accounts, and regulate intrastate storage services. The FERC regulates interstate storage services. The FERC uses 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 their last regulatory filing. The OPUC Schedule 80 rates are tied to the FERC rates, and are updated whenever we modify our FERC maximum rates. 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 2016, approximately 69% of our storage revenues were derived from FERC, Oregon, and Washington regulated operations and approximately 31% from California operations.

#### Most Recent General Rate Cases

**OREGON.** Effective November 1, 2012, the OPUC authorized rates to customers based on an ROE of 9.5%, an overall rate of return of 7.78%, and a capital structure of 50% common equity and 50% long-term debt.

**WASHINGTON.** Effective January 1, 2009, the WUTC authorized rates to customers based on an ROE of 10.1% and an overall rate of return of 8.4% with a capital structure of 51% common equity, 5% short-term debt, and 44% long-term debt.

**FERC.** We are required under our Mist interstate storage certificate authority and rate approval orders to file every five years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for our interstate storage services. In December 2013, we filed a rate petition, which was approved in 2014, and allows for the maximum cost-based rates for our interstate gas storage services. These rates were effective January 1, 2014, with the rate changes having no significant impact on our revenues.

We continuously monitor the utility and evaluate the need for a rate case. Currently, we are contemplating filing an Oregon rate case in late 2017 or in 2018 with a Washington rate case thereafter.

#### Regulatory Proceeding Updates

During 2017, we were involved in the regulatory activities discussed below.

**SYSTEM INTEGRITY PROGRAM (SIP).** Upon completion of our bare-steel replacement program, we filed a request to extend the SIP program. The OPUC suspended our filing and ordered additional processes, including involvement of other local distribution companies' (LDCs) in the state, before making a final decision. In 2016, we withdrew our request to extend the SIP program and instead focused our efforts on establishing guidelines for future safety cost trackers with the OPUC. In 2016, an all-party agreement establishing guidelines was filed with the OPUC and on March 6, 2017, the Commission issued an order adopting the agreement. The order allows LDCs to request safety cost recovery mechanisms under the guidelines established by the parties and requires LDCs to file annual safety project plans for OPUC and stakeholder review.

**HEDGING.** In 2014 the OPUC opened a docket to discuss broader gas hedging practices across gas utilities in Oregon. This docket was divided into two phases. The first phase was focused on an analytical review of hedging and hedging practices. We are currently working through the second phase regarding potential hedging guidelines, and seeking an agreement through discussions with the parties. After the second phase is complete, a status report

or other filing will be submitted to the OPUC, and the remainder of the process will be determined at that time. Currently, we anticipate resolution of the docket in the second half of 2017.

The WUTC also conducted an investigation into the hedging practices of gas utilities operating in Washington, and considered whether it should require gas utilities to implement certain hedging practices. During 2016, the WUTC received and reviewed comments from all parties and issued a policy statement on March 13, 2017 outlining their expectations. The policy statement supports risk-responsive hedging strategies that are adaptable to variability in the market and requires gas utilities to submit with their 2017 PGA a preliminary hedging plan that outlines the utilities' intended path to incorporate risk-responsive hedging strategies. Beginning with the 2018 PGA, gas utilities must submit an annual comprehensive hedging plan that supports integration of risk responsive strategies into their hedging framework. Beginning with the 2019 PGA filing, utilities must provide a full strategy implementation plan for years 2020 and beyond. We are currently evaluating the WUTC order to determine its impact to our current hedging practices, and plan to submit our preliminary hedging plan with our 2017 PGA, as directed by the WUTC.

**INTERSTATE STORAGE AND OPTIMIZATION SHARING.** We received an Order from the OPUC in March 2015 on their review of 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. The Order requires a third-party cost study to be performed and the results of the cost study may initiate a new docket or the re-opening of the original docket. In 2017, all parties agreed and hired a third-party consultant to perform the study and are continuing to facilitate completion of the work directed by the OPUC. We expect completion of this study in the second half of 2017.

**CARBON SOLUTIONS PROGRAM.** Oregon Senate Bill 844 (SB 844) required the OPUC to develop rules and programs to reduce carbon emissions in Oregon. In June 2015, we submitted our first project related to Combined Heat and Power (CHP) for OPUC approval. The submitted CHP program would pay owners of new commercial- and industrial-scale CHP systems for verified carbon emission reductions. In April 2016, the OPUC issued an order declining our program as submitted and provided guidance on program structure for potential future submissions. We have worked with the stakeholders to reach common ground and are contemplating our next steps for this program.

**INTEGRATED RESOURCE PLAN (IRP).** We filed our 2016 Oregon and Washington IRPs on August 26, 2016. We received a letter of compliance from the WUTC in December 2016 and acknowledgment by the OPUC in February 2017. The IRP included analysis of different growth scenarios and corresponding resource acquisition strategies. The analysis is needed to develop supply and demand resource requirements, consider uncertainties in the planning process, and to establish a plan for providing reliable and low cost natural gas service.

**GAS INCIDENT INVESTIGATION.** On October 19, 2016, there was a natural gas explosion in Portland, Oregon after a third-party contractor damaged a NW Natural service line. The contractor was not working for NW Natural at the time. NW Natural and local authorities responded to the event and evacuated the necessary building prior to the ignition. No fatalities or life-threatening injuries were sustained. On March 30, 2017, the OPUC released its investigation report regarding the incident, finding that NW Natural followed federal emergency response requirements. NW Natural did not receive any fines or penalties as a result of the report or the incident. We continue to focus on safety and enhancements to our incident response and reporting procedures, both of which are operational priorities. We will also continue to partner with other first responders in our community for on-site emergency response coordination.

**DEPRECIATION STUDY.** Under OPUC regulations, the utility is required to file a depreciation study every five years to update or justify maintaining the existing depreciation rates. In December 2016, we filed the required depreciation study with the Commission and it is currently under review. We do not anticipate the study to materially change our current depreciation rates.

**HOLDING COMPANY APPLICATION.** In February 2017, we filed applications with the OPUC, WUTC, and CPUC for approval to reorganize under a holding company structure. The filing of regulatory applications is the first of many steps required to form a holding company. We expect that the regulatory process will take six to nine months, and will result in the OPUC, WUTC and CPUC authorizing a holding company structure subject to certain restrictions, or "ring-fencing" provisions applicable to NW Natural, the entity that currently, and would continue to, house our utility operations. We do not expect a material operational or financial impact to our business as a result of the contemplated reorganization. For further discussion of our holding company application, see Part II, Item 7

"Results of Operations—Regulatory Matters— *Regulatory Proceeding Updates*" in our 2016 Form 10-K .

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

Each year, we typically hedge gas prices on approximately 75% of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2016-17 gas year (November 1, 2016 - October 31, 2017) hedged at 75% of our forecasted sales volumes, including 48% in financial swap and option contracts and 27% in physical gas supplies. As part of the guidance issued by the WUTC on hedging and our open hedge docket with the OPUC, we are evaluating our hedge strategies for Oregon and Washington.

In addition to the amount hedged for the current gas contract year, we are also hedged in future years at approximately 46% for the 2017-18 gas year and between 4% and 18% for annual requirements over the subsequent five gas years as of March 31, 2017 . Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather, economic conditions, and estimated gas reserve production. Also, our gas storage inventory levels may increase or decrease with storage expansion, changes in storage contracts with third parties, variations in the heat content of the gas, and/or storage recall by the utility.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20% or 10% of the difference between actual and estimated gas costs, respectively. For the 2015-16 and 2016-17 gas years, we selected the 80% and 90% deferral option, 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 TEST REVIEW.** We are subject to an annual earnings review in Oregon to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33% of the amount above that level is required to be deferred or refunded to customers. Under this provision, if we select the 80% deferral gas cost 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. For the 2015-16 and 2016-17 periods, we selected the 80% and 90% deferral option, respectively. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2015 and 2016, the ROE threshold was 10.60%, and 11.06%, respectively. There were no refunds required for 2015. We filed the 2016 earnings test in May 2017 and do not expect a customer refund adjustment for 2016 based on our results.

**GAS RESERVES.** In 2011, the OPUC approved the Encana gas reserves transaction to provide long-term gas price protection for our utility customers and determined our costs under the agreement would be recovered, on an ongoing basis through our annual PGA mechanism. Gas produced from our interests is sold at then prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are included in our cost of gas. The cost of gas, including a carrying cost for the rate base investment made under the original agreement, is included in our annual Oregon PGA filing, which allows us to recover these costs through customer rates. Our net investment under the original agreement earns a rate of return.

In March 2014, we amended the original gas reserves agreement in response to Encana's sale of its interest in the Jonah field located in Wyoming to Jonah Energy. Under our amended agreement with Jonah Energy, we have the option to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate working interest for each well in which we invest. We did not have the opportunity to participate in additional wells during 2015, 2016, or the three months ended March 31, 2017 , but we may have the opportunity in the future.

**DECOUPLING.** In Oregon, we have a decoupling mechanism. Decoupling is intended to break the link between utility earnings and the quantity of gas consumed by customers, removing any financial incentive by the utility to discourage customers' efforts to conserve energy.

The Oregon decoupling mechanism was reauthorized and the baseline expected usage per customer was set in the 2012 Oregon general rate case. This mechanism employs a use-per-customer decoupling calculation, which adjusts margin revenues to account for the difference between actual and expected customer volumes. The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the annual PGA filing. In Washington, customer use is not covered by such a tariff. See "Business Segments —*Local Gas Distribution Utility Operations*" below.

**WARM.** In Oregon, we have an approved weather normalization mechanism, which is applied to residential and commercial customer bills. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to bills from December through May of each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers. The collections of any unbilled WARM amounts are deferred and earn a carrying charge until collected in the PGA the following year. This weather normalization mechanism was reauthorized in the 2012 Oregon general rate case without an expiration date. Residential and commercial customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of March 31, 2017, 9 % of total customers had opted out. We do not have a weather normalization mechanism approved for residential and commercial Washington customers, which account for about 11 % of total customers. See "Business Segments —*Local Gas Distribution Utility Operations*" below.

**INDUSTRIAL TARIFFS.** The OPUC and WUTC have approved tariffs covering utility service to our major industrial customers, including terms, which are intended to give us certainty in the level of gas supplies we need to acquire to serve this customer group. The terms include, among other things, an annual election period, special pricing provisions for out-of-cycle changes, and a requirement that industrial customers complete the term of their service election under our annual PGA tariff.

**ENVIRONMENTAL COST DEFERRAL AND SRRM.** We have a SRRM through which we track and have the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test.

Under the SRRM collection process there are three types of deferred environmental remediation expense:

- Pre-review - This class of costs represents remediation spend that has not yet been deemed prudent by the OPUC. Carrying costs on these remediation expenses are recorded at our authorized cost of capital. We anticipate the prudence review for annual costs and approval of the earnings test prescribed by the OPUC to occur by the third quarter of the following year.
- Post-review - This class of costs represents remediation spend that has been deemed prudent and allowed after applying the earnings test, but is not yet included in amortization. We earn a carrying cost on these amounts at a rate equal to the five-year treasury rate plus 100 basis points.
- Amortization - This class of costs represents amounts included in current customer rates for collection and is generally calculated as one-fifth of the post-review deferred balance. We earn a carrying cost equal to the amortization rate determined annually by the OPUC, which approximates a short-term borrowing rate.

In addition, as a result of the 2015 and 2016 Orders, the Order also provides for the annual collection of \$5 million from Oregon customers through a tariff rider. As we collect amounts from customers, we recognize these collections as revenue and separately amortize an equal and offsetting amount of our deferred regulatory asset balance through the environmental remediation operating expense line shown separately in the operating expense section of the income statement. See Note 13 in our 2016 Form 10-K.

The SRRM earnings test is an annual review of our adjusted utility ROE compared to our authorized utility ROE, which is currently 9.5%. To apply the earnings test first we must determine what if any costs are subject to the test through the following calculation:

|                                                       |
|-------------------------------------------------------|
| Annual spend                                          |
| Less: \$5 million base rate rider <sup>(1)</sup>      |
| Prior year carry-over <sup>(2)</sup>                  |
| \$5 million insurance + interest on insurance         |
| Total deferred annual spend subject to earnings test  |
| Less: over-earnings adjustment, if any                |
| Add: deferred interest on annual spend <sup>(3)</sup> |
| Total amount transferred to post-review               |

<sup>(1)</sup> Base rate rider went into Oregon customer rates beginning November 1, 2015.

<sup>(2)</sup> Prior year carry-over results when the prior year amount transferred to post-review is negative. The negative amount is carried over to offset annual spend in the following year.

<sup>(3)</sup> Deferred interest is added to annual spend to the extent the spend is recoverable.

To the extent the utility earns at or below its authorized Return on Equity (ROE), remediation expenses and interest in excess of the \$5 million tariff rider and \$5 million of insurance proceeds are recoverable through the SRRM. To the extent the utility earns more than its authorized ROE in a year, the utility is required to cover environmental expenses and interest on expenses greater than the \$10 million with those earnings that exceed its authorized ROE.

For 2016, we have performed this test, which we submitted to the OPUC in May 2017, and we do not expect an earnings test adjustment for 2016 based on our results.

The WUTC has also previously authorized the deferral of environmental costs, if any, that are appropriately allocated to Washington customers. This Order was effective in January 2011 with cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding. Annually, we review all regulatory assets for recoverability or more often if circumstances warrant. If we should determine all or a portion of these regulatory assets no longer met 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 was made.

**PENSION COST DEFERRAL AND PENSION BALANCING ACCOUNT.** Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's authorized rate of return, which is currently 7.78%. 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, excluding interest, were \$1.5 million and \$1.6 million during the three months ended March 31, 2017 and 2016, respectively.

**INTERSTATE STORAGE AND OPTIMIZATION SHARING.** In 2017, we filed for regulatory approval to refund an interstate storage credit of \$11.7 million to our Oregon utility customers. In June of 2016, we received regulatory approval to provide an interstate storage credit of \$9.4 million to our Oregon utility customers, which was reflected in their June 2016 bills. The 2017 and 2016 customer credits are part of our regulatory incentive sharing mechanism related to non-utility Mist storage and asset management services. The Washington portion of these credits is included in the Washington PGA.

**GAS COST SHARING CUSTOMER CREDITS.** In addition, in June of 2016, we credited \$19.4 million to customers for their portion of the gas cost sharing incentive for the 2015-16 gas year, resulting from lower projected gas costs, which were driven by warmer weather, lower volume usage, and lower market prices.

For a discussion of other rate mechanisms, see Part II, Item 7, "Results of Operations—Regulatory Matters— *Rate Mechanisms* in our 2016 Form 10-K .

### **Business Segments - Local Gas Distribution Utility Operations**

Utility margin results are primarily affected by customer growth, revenues from rate-base additions, and, to a certain extent, by changes in delivered volumes 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 designed 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, WARM, 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, but not eliminate, the volatility of customer bills and our utility's earnings. See "Regulatory Matters— *Rate Mechanisms*" above.

Utility segment highlights include:

| <i>Dollars and therms in thousands, except EPS data</i> | Three Months Ended March 31, |            | QTR Change |
|---------------------------------------------------------|------------------------------|------------|------------|
|                                                         | 2017                         | 2016       |            |
| Utility net income                                      | \$ 40,192                    | \$ 35,852  | \$ 4,340   |
| EPS - utility segment                                   | 1.40                         | 1.30       | 0.10       |
| Gas sold and delivered (in therms)                      | 467,639                      | 372,549    | 95,090     |
| Utility margin <sup>(1)</sup>                           | \$ 142,161                   | \$ 136,664 | \$ 5,497   |

<sup>(1)</sup> See Utility Margin Table below for a reconciliation and additional detail.

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016.** The primary factors contributing to the \$4.3 million or \$0.10 per share increase in utility net income were as follows:

- a \$5.5 million increase in utility margin primarily due to:
  - a \$2.4 million increase from customer growth; offset by
  - a \$2.7 million decrease in gains from gas cost incentive sharing due to actual gas prices that were comparatively higher than the prior year, but lower than those estimated in the 2016-17 PGA.
  - the majority of the remaining increase was due to the effects of colder than average weather in 2017 compared to a warmer than average winter in the prior period. Weather impacts utility margins from our Washington customers where we do not have a weather normalization mechanism in place, and 9% of our Oregon customers who opted out of weather normalization;
- a \$3.0 million increase in other income (expense), net, primarily due to the environmental interest disallowance recognized in 2016; partially offset by
- a \$0.9 million increase in operations and maintenance expense largely from payroll and benefits due to increased headcount over the past twelve months; and
- a \$0.9 million increase in depreciation expense primarily due to additional capital expenditures.

Total utility volumes sold and delivered in 2017 increased 26% over 2016 as weather was 37% colder during the first quarter of 2017 compared to the same period last year and 17% colder than average.

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

| <i>In thousands, except degree day and customer data</i>    | Three Months Ended March 31, |             | Favorable/(Unfavorable) |
|-------------------------------------------------------------|------------------------------|-------------|-------------------------|
|                                                             | 2017                         | 2016        | QTR Change              |
| <b>Utility volumes (therms):</b>                            |                              |             |                         |
| Residential and commercial sales                            | 327,523                      | 242,874     | 84,649                  |
| Industrial sales and transportation                         | 140,116                      | 129,675     | 10,441                  |
| Total utility volumes sold and delivered                    | 467,639                      | 372,549     | 95,090                  |
| <b>Utility operating revenues:</b>                          |                              |             |                         |
| Residential and commercial sales                            | \$ 280,277                   | \$ 237,672  | \$ 42,605               |
| Industrial sales and transportation                         | 18,903                       | 17,664      | 1,239                   |
| Other revenues                                              | 1,375                        | 1,411       | (36)                    |
| Less: Revenue taxes                                         | 7,829                        | 6,643       | 1,186                   |
| Total utility operating revenues                            | 292,726                      | 250,104     | 42,622                  |
| Less: Cost of gas                                           | 143,611                      | 108,411     | (35,200)                |
| Less: Environmental remediation expense                     | 6,954                        | 5,029       | (1,925)                 |
| Utility margin                                              | \$ 142,161                   | \$ 136,664  | \$ 5,497                |
| <b>Utility margin: <sup>(1)</sup></b>                       |                              |             |                         |
| Residential and commercial sales                            | \$ 131,040                   | \$ 123,484  | \$ 7,556                |
| Industrial sales and transportation                         | 8,692                        | 8,201       | 491                     |
| Miscellaneous revenues                                      | 1,373                        | 1,406       | (33)                    |
| Gain from gas cost incentive sharing                        | 951                          | 3,654       | (2,703)                 |
| Other margin adjustments                                    | 105                          | (81)        | 186                     |
| Utility margin                                              | \$ 142,161                   | \$ 136,664  | \$ 5,497                |
| <b>Degree days</b>                                          |                              |             |                         |
| Average <sup>(2)</sup>                                      | 1,855                        | 1,871       | (16)                    |
| Actual                                                      | 2,169                        | 1,585       | 37%                     |
| Percent colder (warmer) than average weather <sup>(2)</sup> | 17%                          | (15)%       |                         |
| <b>As of March 31,</b>                                      |                              |             |                         |
| <b>Customers - end of period:</b>                           | <b>2017</b>                  | <b>2016</b> | <b>Change</b>           |
| Residential customers                                       | 661,217                      | 650,268     | 10,949                  |
| Commercial customers                                        | 67,838                       | 66,748      | 1,090                   |
| Industrial customers                                        | 1,012                        | 993         | 19                      |
| Total number of customers                                   | 730,067                      | 718,009     | 12,058                  |
| <b>Customer growth (12 month rolling):</b>                  |                              |             |                         |
| Residential customers                                       | 1.7%                         |             |                         |
| Commercial customers                                        | 1.6%                         |             |                         |
| Industrial customers                                        | 1.9%                         |             |                         |
| Total customer growth                                       | 1.7%                         |             |                         |

<sup>(1)</sup> Amounts reported as margin for each category of customers are operating revenues, which are net of revenue taxes, less cost of gas and environmental remediation expense.

<sup>(2)</sup> Average weather represents the 25-year average of heating degree days, as determined in our 2012 Oregon general rate case.

## Residential and Commercial Sales

Residential and commercial sales highlights include:

| In thousands                     | Three Months Ended March 31, |            | QTR Change |
|----------------------------------|------------------------------|------------|------------|
|                                  | 2017                         | 2016       |            |
| <u>Volumes (therms):</u>         |                              |            |            |
| Residential sales                | 209,650                      | 155,232    | 54,418     |
| Commercial sales                 | 117,873                      | 87,642     | 30,231     |
| Total volumes                    | 327,523                      | 242,874    | 84,649     |
| <u>Operating revenues:</u>       |                              |            |            |
| Residential sales                | \$ 188,568                   | \$ 160,700 | \$ 27,868  |
| Commercial sales                 | 91,709                       | 76,972     | 14,737     |
| Total operating revenues         | \$ 280,277                   | \$ 237,672 | \$ 42,605  |
| <u>Utility margin:</u>           |                              |            |            |
| Residential:                     |                              |            |            |
| Sales                            | \$ 105,328                   | \$ 81,661  | \$ 23,667  |
| Weather normalization            | (11,050)                     | 9,231      | (20,281)   |
| Decoupling                       | (2,054)                      | (3,935)    | 1,881      |
| Total residential utility margin | 92,224                       | 86,957     | 5,267      |
| Commercial:                      |                              |            |            |
| Sales                            | 40,106                       | 30,905     | 9,201      |
| Weather normalization            | (4,289)                      | 3,746      | (8,035)    |
| Decoupling                       | 2,999                        | 1,876      | 1,123      |
| Total commercial utility margin  | 38,816                       | 36,527     | 2,289      |
| Total utility margin             | \$ 131,040                   | \$ 123,484 | \$ 7,556   |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016.** The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 84.6 million therms, or 35% , due to comparatively colder weather in the first quarter of 2017 and customer growth;
- operating revenues increased \$42.6 million , due to a 35% increase in sales volumes; and
- utility margin increased \$7.6 million , due to customer growth and the effects of comparatively colder weather on our Washington customers and Oregon customers that opted out of the weather normalization mechanism.

### Industrial Sales and Transportation

Industrial customers have the option of purchasing sales or transportation services from the utility. Under the sales service, the customer buys the gas commodity from the utility. Under the transportation service, the customer buys the gas commodity directly from a third-party gas marketer or supplier. Our gas commodity cost is primarily a pass-through cost to customers; therefore, our profit margins are not materially affected by an industrial customer's decision to purchase gas from us or from third parties. Industrial and large commercial customers may also select between firm and interruptible service options, with firm services generally providing higher profit margins compared to interruptible services. To help manage gas supplies, our industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election which becomes effective November 1, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

Industrial sales and transportation highlights include:

|                                                    | Three Months Ended March 31, |          |            |
|----------------------------------------------------|------------------------------|----------|------------|
| <i>In thousands</i>                                | 2017                         | 2016     | QTR Change |
| <u>Volumes (therms):</u>                           |                              |          |            |
| Industrial - firm sales                            | 10,376                       | 9,424    | 952        |
| Industrial - firm transportation                   | 48,729                       | 44,201   | 4,528      |
| Industrial - interruptible sales                   | 16,977                       | 15,050   | 1,927      |
| Industrial - interruptible transportation          | 64,034                       | 61,000   | 3,034      |
| Total volumes                                      | 140,116                      | 129,675  | 10,441     |
| <u>Utility margin:</u>                             |                              |          |            |
| Industrial - firm and interruptible sales          | \$ 3,340                     | \$ 3,163 | \$ 177     |
| Industrial - firm and interruptible transportation | 5,352                        | 5,038    | 314        |
| Industrial - sales and transportation              | \$ 8,692                     | \$ 8,201 | \$ 491     |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016.** Sales and transportation volumes increased by 10.4 million therms and utility margin increased \$0.5 million due to higher usage from colder weather compared to the prior year.

### **Cost of Gas**

Cost of gas as reported by the utility includes gas purchases, gas withdrawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, gas reserves costs, 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 which has been described under "Regulatory Matters—Rate Mechanisms— *Purchased Gas Adjustment*" above. In addition to the PGA incentive sharing mechanism, gains and losses from hedge contracts entered into after annual PGA rates are effective for Oregon customers are also required to be shared and therefore may impact net income. Further, we also have a regulatory agreement whereby we earn a rate of return on our investment in the gas reserves acquired under the original agreement with Encana and include gas from our amended gas reserves agreement at a fixed rate of \$0.4725 per therm, which are also reflected in utility margin. See "Application of Critical Accounting Policies and Estimates— *Accounting for Derivative Instruments and Hedging Activities*" in our 2016 Form 10-K.

Cost of gas highlights include:

| <i>Dollars and therms in thousands</i>              | Three Months Ended March 31, |            | QTR Change |
|-----------------------------------------------------|------------------------------|------------|------------|
|                                                     | 2017                         | 2016       |            |
| Cost of gas                                         | \$ 143,611                   | \$ 108,411 | \$ 35,200  |
| Volumes sold (therms) <sup>(1)</sup>                | 354,876                      | 267,349    | 87,527     |
| Average cost of gas (cents per therm)               | \$ 0.40                      | \$ 0.41    | \$ (0.01)  |
| Gain from gas cost incentive sharing <sup>(2)</sup> | 951                          | 3,654      | (2,703)    |

<sup>(1)</sup> This calculation excludes volumes delivered to transportation only customers.

<sup>(2)</sup> For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms— *Purchased Gas Adjustment*" above.

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016.** Cost of gas increased \$ 35.2 million , or 32% , reflecting a 33% increase in volumes due to comparatively colder weather in the first quarter of 2017 and customer growth.

### **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% undivided 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 the gas storage businesses segment.

Gas storage segment highlights include:

| <i>In thousands, except EPS data</i> | Three Months Ended March 31, |          | QTR Change |
|--------------------------------------|------------------------------|----------|------------|
|                                      | 2017                         | 2016     |            |
| Operating revenues                   | \$ 4,541                     | \$ 5,369 | \$ (828)   |
| Operating expenses                   | 3,935                        | 3,644    | 291        |
| Gas storage net income               | 61                           | 736      | (675)      |
| EPS - gas storage segment            | —                            | 0.03     | (0.03)     |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016.** Our gas storage segment net income decreased \$0.7 million or \$0.03 per share primarily due to the following factors:

- a \$0.8 million decrease in gas storage revenues largely due to lower asset management revenues from our Mist facility and transportation capacity offset by slightly higher firm prices at our Gill Ranch facility for the 2016-17 storage year; and
- a \$0.3 million increase in operating expenses largely due to routine pipeline and compressor maintenance at our Gill Ranch facility.

Our Mist gas storage facility benefits from limited competition from other Pacific Northwest storage facilities primarily because of its geographic location. 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. We have contracted both our Mist and Gill Ranch facilities for the 2017-18 gas storage year. Our Mist facility remains under long-term contracts at similar prices to prior periods. Our Gill Ranch facility is contracted with approximately half of the capacity in firm contracts at slightly higher prices than the prior gas storage year. The remaining capacity at the Gill Ranch facility is under asset management agreements with a third-party and will be subject to market pricing.

Though prices at our Gill Ranch facility have improved slightly over the last several years, prices continue to remain low relative to our original long-term contracts, which ended primarily in the 2013-14 gas storage year. In the future, we may see continued price improvement or an increase in the demand for natural gas driven by a number of factors, including changes in electric generation triggered by California's renewable portfolio standards, an increase in use of alternative fuels to meet carbon emission reduction targets, recovery of the California economy, growth of domestic industrial manufacturing, potential exports of liquefied natural gas from the west coast, and other favorable storage market conditions in and around California. These factors, if they occur, may contribute to higher summer/winter natural gas price spreads, gas price volatility, and gas storage values.

In October 2015, a significant natural gas leak occurred at an unaffiliated southern California gas storage facility that persisted into early 2016. At this time, we do not know the long-term effects of this incident on gas storage prices. In September 2016, legislation was passed and signed into law by the Governor of California in response to the incident, which directed the California Department of Oil, Gas and Geothermal Resources (DOGGR) to develop new regulations for gas storage wells. While the regulations are still under development and their ultimate impact is unknown, it is likely that the pending DOGGR regulations and finalized PHMSA gas storage regulations will result in higher costs for all storage providers. The potential costs of compliance could include one-time capital expenditures and/or ongoing operations and maintenance costs. As a result of the legislation and pending regulations, the nature of, and demand for, future storage contracts, as well as market values in California could be impacted and remain uncertain at this time.

If such new regulation and legislation require significant capital and on-going spending to upgrade or maintain the facility, we are unsuccessful in identifying new higher value customers, future storage values do not improve, an increased demand and other favorable market conditions for natural gas storage do not materialize, and/or volatility does not return to the gas storage market, this could have a negative impact on our future cash flows and could result in impairment of our Gill Ranch gas storage facility, which had a net book value of \$194.9 million at March 31, 2017. We continue to assess these conditions along with other strategic alternatives and their impact on the value of the asset on an ongoing basis. Refer to Note 2 in our 2016 Form 10-K for more information regarding our accounting policy for impairment of long-lived assets.

### Other

Other primarily consists of NNG Financial's equity investment in KB Pipeline, an equity investment in TWH, which has invested in the Trail West pipeline project, and other miscellaneous non-utility investments and business activities. There were no significant changes in our other activities in during the three months ended March 31, 2017. See Note 4 and Note 11 for further details on other activities and our investment in TWH.

## Consolidated Operations

### Operations and Maintenance

Operations and maintenance highlights include:

| <i>In thousands</i>        | Three Months Ended March 31, |           |    | QTR Change |
|----------------------------|------------------------------|-----------|----|------------|
|                            | 2017                         | 2016      |    |            |
| Operations and maintenance | \$ 40,420                    | \$ 38,939 | \$ | 1,481      |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016.** Operations and maintenance expense increased \$1.5 million, primarily related to payroll and benefits expense largely from increased headcount over the past twelve months and higher non-payroll expenses related to system integrity maintenance.

Delinquent customer receivable balances continue to remain at historically low levels. The utility's annualized bad debt expense as a percent of revenues was 0.1% and 0.2% for the three months ended March 31, 2017 and 2016, respectively.

### Other Income (Expense), Net

Other income (expense), net highlights include:

| <i>In thousands</i>         | Three Months Ended March 31, |            |    | QTR Change |
|-----------------------------|------------------------------|------------|----|------------|
|                             | 2017                         | 2016       |    |            |
| Other income (expense), net | \$ 881                       | \$ (2,309) | \$ | 3,190      |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016.** Other income (expense), net, increased \$3.2 million primarily due to the January 2016 Order from the OPUC, which resulted in a \$2.8 million interest disallowance in 2016. In addition, other income (expense), net benefited by approximately \$0.3 million from the equity portion of AFUDC.

### Interest Expense, Net

Interest expense, net highlights include:

| <i>In thousands</i>   | Three Months Ended March 31, |          |    | QTR Change |
|-----------------------|------------------------------|----------|----|------------|
|                       | 2017                         | 2016     |    |            |
| Interest expense, net | \$ 9,876                     | \$ 9,736 | \$ | 140        |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016.** Interest expense, net remained flat overall, compared to the prior year. However, interest expense increased by \$0.4 million due to the issuance of long-term debt in December 2016 and was partially offset by an increase of \$0.3 million from the interest-related portion of AFUDC.

### Income Tax Expense

Income tax expense highlights include:

| <i>In thousands</i> | Three Months Ended March 31, |           |    | QTR Change |
|---------------------|------------------------------|-----------|----|------------|
|                     | 2017                         | 2016      |    |            |
| Income tax expense  | \$ 26,923                    | \$ 25,386 | \$ | 1,537      |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED TO MARCH 31, 2016.** The increase in income tax expense was correlated with the change in pre-tax income.

## 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, and 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 on both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt retirements and short-term commercial paper maturities. See " *Liquidity and Capital Resources*" below and Note 6 .

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

|                                                                 | March 31, |        |
|-----------------------------------------------------------------|-----------|--------|
|                                                                 | 2017      | 2016   |
| Common stock equity                                             | 54.8%     | 51.5%  |
| Long-term debt                                                  | 41.3      | 36.4   |
| Short-term debt, including current maturities of long-term debt | 3.9       | 12.1   |
| Total <sup>(1)</sup>                                            | 100.0%    | 100.0% |

<sup>(1)</sup> Ratios reflect debt balances net of any unamortized debt issuance costs.

### Liquidity and Capital Resources

At March 31, 2017 we had \$40.6 million of cash and cash equivalents compared to \$4.3 million at March 31, 2016 due to higher cash collections from customers as a result of colder than average weather and lower working capital requirements. 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.

### Utility Segment

For the utility segment, the short-term borrowing requirements typically peak during colder winter months when the utility borrows money to cover the lag between natural gas purchases and bill collections from customers. Our short-term liquidity for the utility is primarily provided by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, as well as available cash from multi-year credit facilities, short-term credit facilities, company-owned life insurance policies, the sale of long-term debt, and issuances of equity. Utility long-term debt and equity issuance proceeds are primarily used to finance utility capital expenditures, refinance maturing debt of the utility, and provide temporary funding for other general corporate purposes of the utility.

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 or issue letters of credit from our back-up credit facility. In the event we are not able to issue new debt due to adverse market conditions or other reasons, we expect 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 statement 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 March 31, 2017 , we have Board authorization to issue up to \$175 million of additional FMBs. We also have OPUC approval to issue up to \$175 million of additional long-term debt for approved purposes.

In the event our senior unsecured long-term debt 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 forms of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings while we were in a net loss position. We were not required to post collateral at March 31, 2017 . However, if the credit risk-related contingent features underlying these contracts were triggered on March 31, 2017 , assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post \$1.1 million of collateral with our counterparties. See " *Credit Ratings*" below and Note 12.

Other items that may have a significant impact on our liquidity and capital resources include pension contribution requirements, discontinuation of bonus tax depreciation and environmental expenditures.

With respect to pensions, we expect to make significant contributions to our company-sponsored defined benefit plan, which is closed to new employees, over the next several years until we are fully funded under the Pension Protection Act rules, including the new rules issued under the Moving Ahead for Progress in the 21st Century Act (MAP-21) and the Highway and Transportation Funding Act of 2014 (HATFA). See "Application of Critical Accounting Policies— *Accounting for Pensions and Postretirement Benefits* " in the 2016 Form 10-K.

### **Gas Storage**

Short-term liquidity for the gas storage segment is supported by cash balances, internal cash flow from operations, equity contributions from its parent company, and, if necessary, additional external financing.

The amount and timing of our Gill Ranch facility's cash flows from year to year are uncertain, as the majority of these storage contracts are currently short-term. We have seen slightly higher firm contract prices over the last several years, but overall prices are still lower than the long-term contracts that expired at the end of the 2013-14 storage year. While we expect continuing challenges for Gill Ranch in 2017, we do not anticipate material changes in our ability to access sources of cash for short-term liquidity.

### **Consolidated**

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

### **Short-Term Debt**

Our primary source of utility short-term liquidity is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans 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 and bank loans are 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 March 31, 2017, our utility had no short-term debt outstanding compared to \$164.9 million at March 31, 2016 due to lower working capital needs and net proceeds from our equity issuance and issuances of long-term debt instruments in November and December 2016, respectively. The effective interest rate on short-term debt outstanding at March 31, 2016 was 0.8% .

### **Credit Agreements**

We have a \$ 300 million credit agreement, with a feature that allows the Company to request increases in the total commitment amount, up to a maximum of \$ 450 million . The maturity date of the agreement is December 20, 2019.

All lenders under the agreement are major financial institutions with committed balances and investment grade credit ratings as of March 31, 2017 as follows:

| <i>In millions</i>         |                 |
|----------------------------|-----------------|
| Lender rating, by category | Loan Commitment |
| AA/Aa                      | \$ 234          |
| A/A                        | 66              |
| Total                      | \$ 300          |

Based on credit market conditions, it is possible one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency; however, we do not believe this risk to be imminent due to the lenders' strong investment-grade credit ratings.

Our credit agreement permits the issuance of letters of credit in an aggregate amount of up to \$ 100 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 credit agreement at March 31, 2017 or 2016 . The 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 March 31, 2017 and 2016 , with consolidated indebtedness to total capitalization ratios of 45.1% and 48.5% , 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, potentially affecting our access to the capital markets including the commercial paper market. Our credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. The following table summarizes our current debt ratings:

|                                    | S&P    | Moody's |
|------------------------------------|--------|---------|
| Commercial paper (short-term debt) | A-1    | P-2     |
| Senior secured (long-term debt)    | AA-    | A1      |
| Senior unsecured (long-term debt)  | n/a    | A3      |
| Corporate credit rating            | A+     | n/a     |
| Ratings outlook                    | Stable | Stable  |

The above 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 Retirement of Long-Term Debt**

We did not retire any debt in the first quarter of 2017. Over the next twelve months, \$40 million of FMBs with a coupon rate of 7.00% and maturity in August 2017 and \$22 million of FMBs with a coupon rate of 6.60% and maturity in March 2018 are expected to be retired.

See Part II, Item 7, "Financial Condition— *Contractual Obligations* " in our 2016 Form 10-K for long-term debt maturing over the next five years.

### **Cash Flows**

#### **Operating Activities**

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:

| <i>In thousands</i>                   | Three Months Ended March 31, |            |    | QTR Change |
|---------------------------------------|------------------------------|------------|----|------------|
|                                       | 2017                         | 2016       |    |            |
| Cash provided by operating activities | \$ 145,166                   | \$ 146,138 | \$ | (972)      |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED to MARCH 31, 2016.** The significant factors contributing to the \$1.0 million decrease in cash flows provided by operating activities were as follows:

- a decrease of \$5.7 million in tax-related accounts primarily due to increases in accrued taxes and net deferred tax liabilities primarily due to the continuation of bonus depreciation in December 2016;

- a net decrease of \$2.5 million from changes in working capital related to receivables, inventories, and accounts payable reflecting colder than average weather in 2017 compared to warmer than average weather in the prior period ; partially offset by
- an increase of \$4.9 million from changes in deferred gas cost balances due to an increase in natural gas prices compared to the prior year, which remained lower than those embedded in the PGA .

The non-cash qualified defined benefit pension expense recognized on the income statement for the three months ended March 31, 2017 and 2016 was \$1.3 million . Changes in pension expense are mitigated by our balancing account in Oregon; and therefore, net non-cash pension expenses are expected to remain relatively flat in the coming years.

During the three months ended March 31, 2017 , we contributed \$3.2 million to our utility's qualified defined benefit pension plan, compared to \$2.9 million for the same period in 2016 . The amount and timing of future contributions will depend on market interest rates and investment returns on the plans' assets. See Note 7.

Bonus income tax depreciation for 2015 was not enacted until December 18, 2015, which was extended retroactively back to January 1, 2015. As a result, estimated income tax payments were made throughout 2015 without the benefit of bonus depreciation for the year. This delayed the cash flow benefit of bonus depreciation until a refund could be requested and received. We received a refund of federal income tax overpayments of \$7.9 million in the first quarter of 2016. As a result of the Federal Protecting Americans From Tax Hikes Act of 2015, bonus depreciation is now enacted through 2019. Accordingly, we do not anticipate similar refunds from income tax overpayments related to bonus depreciation, in the near future.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations. For information on cash flow requirements related to leases and other purchase commitments, see "Financial Condition— *Contractual Obligations* " and Note 14 in the 2016 Form 10-K.

## Investing Activities

Investing activity highlights include:

| <i>In thousands</i>                     | Three Months Ended March 31, |             | QTR Change |
|-----------------------------------------|------------------------------|-------------|------------|
|                                         | 2017                         | 2016        |            |
| Total cash used in investing activities | \$ (38,826)                  | \$ (30,030) | \$ (8,796) |
| Capital expenditures                    | (38,924)                     | (30,054)    | (8,870)    |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED to MARCH 31, 2016.** The \$8.8 million increase in cash used in investing activities was primarily due to higher capital expenditures.

Over the five-year period 2017 through 2021, total utility capital expenditures are estimated to be between \$850 and \$950 million. This range includes the total estimated cost of our North Mist gas storage facility expansion, which is approximately \$128 million. As of March 31, 2017 , we had invested \$29 million in the expansion. The majority of the North Mist capital expenditures, \$80 million to \$90 million, are expected in 2017, with the remaining investment in 2018. We anticipate placing the expansion into service for the winter of 2018-19. Our five-year capital expenditure range also includes estimated capital expenditures between \$75 million to \$85 million related to planned upgrades and refurbishments to storage facilities, including our existing liquefied natural gas facilities in Oregon and our Mist storage facility. In addition, we plan to spend approximately \$20 million to upgrade distribution infrastructure in Clark County, Washington through 2019. The estimated level of utility capital expenditures through 2021 reflects assumptions for continued customer growth, technology investments, distribution system maintenance and improvements, and gas storage facilities maintenance. Most of the required funds are expected to be internally generated over the five-year period, with short-term and long-term debt and bridge financing providing liquidity.

In 2017 , utility capital expenditures are estimated to be between \$225 and \$250 million, and non-utility capital investments of less than \$5 million. Additional spend for gas storage and other investments during and after 2017 are expected to be paid from working capital and additional equity contributions from NW Natural as needed.

## Financing Activities

Financing activity highlights include:

| <i>In thousands</i>                     | Three Months Ended March 31, |              | QTR Change |
|-----------------------------------------|------------------------------|--------------|------------|
|                                         | 2017                         | 2016         |            |
| Total cash used in financing activities | \$ (69,222)                  | \$ (115,998) | \$ 46,776  |
| Change in short-term debt               | (53,300)                     | (105,135)    | 51,835     |

**THREE MONTHS ENDED MARCH 31, 2017 COMPARED to MARCH 31, 2016.** The \$46.8 million decrease in cash used in financing activities was primarily due to lower repayments of \$51.8 million of short-term loans and commercial paper compared to the prior period.

## Ratios of Earnings to Fixed Charges

For the three and twelve months ended March 31, 2017 , and the twelve months ended December 31, 2016, our ratios of earnings to fixed charges, computed using the method outlined by the SEC, were 7.10 , 3.48 and 3.39 , respectively. For this purpose, earnings consist of net income before income taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. 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 “ *Application of Critical Accounting Policies and Estimates* ” in our 2016 Form 10-K. At March 31, 2017 , our total estimated liability related to environmental sites is \$119.9 million . See Note 13 and "Results of Operations—Regulatory Matters —Rate Mechanisms— *Environmental Costs* ”.

## **APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES**

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In preparing our financial statements in accordance with 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 accounting;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes;
- environmental contingencies; and
- impairment of long-lived assets.

There have been no material changes to the information provided in the 2016 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 2016 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 three months ended March 31, 2017. See Part II, Item 1A, “*Risk Factors*” in this report and Part II, Item 7A, “*Quantitative and Qualitative Disclosures about Market Risk*” in the 2016 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 Exchange Act Rule 13a-15(f).

There have been no changes in our internal control over financial reporting that occurred during the quarter ended March 31, 2017 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).

## 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 2016 Form 10-K, we have only routine nonmaterial litigation that occurs in the ordinary course of our business.

### ITEM 1A. RISK FACTORS

There were no material changes from the risk factors discussed in Part I, Item 1A, " *Risk Factors* " in our 2016 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, as amended, during the quarter ended March 31, 2017 :

| Period            | Issuer Purchases of Equity Securities           |                              |                                                                                                 |                                                                                                     |
|-------------------|-------------------------------------------------|------------------------------|-------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------|
|                   | Total Number of Shares Purchased <sup>(1)</sup> | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs <sup>(2)</sup> | Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs <sup>(2)</sup> |
| Balance forward   |                                                 |                              | 2,124,528                                                                                       | \$ 16,732,648                                                                                       |
| 01/01/17-01/31/17 | 706                                             | \$ 58.87                     | —                                                                                               | —                                                                                                   |
| 02/01/17-02/28/17 | 14,811                                          | 58.71                        | —                                                                                               | —                                                                                                   |
| 03/01/17-03/31/17 | 53,296                                          | 60.24                        | —                                                                                               | —                                                                                                   |
| Total             | 68,813                                          | 59.90                        | 2,124,528                                                                                       | \$ 16,732,648                                                                                       |

<sup>(1)</sup> During the quarter ended March 31, 2017 , 20,527 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 48,286 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended March 31, 2017 , no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

<sup>(2)</sup> 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, 2017 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of \$100 million. During the quarter ended March 31, 2017 , no shares of our common stock were repurchased 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.

## SIGNATURE

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

## **NORTHWEST NATURAL GAS COMPANY**

(Registrant)

Dated: May 8, 2017

/s/ Brody J. Wilson

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Brody J. Wilson

Chief Financial Officer, Treasurer, Chief Accounting Officer and  
Controller

## NORTHWEST NATURAL GAS COMPANY

Exhibit Index to Quarterly Report on Form 10-Q  
For the Quarter Ended March 31, 2017

| <b><u>Exhibit Number</u></b> | <b><u>Document</u></b>                                                                                                                                                                                                                                                                                                                                                                                             |
|------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 10.1                         | Corrected Form of Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan (2017).                                                                                                                                                                                                                                                                                                                 |
| 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's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, formatted in Extensible Business Reporting Language (XBRL): <ul style="list-style-type: none"><li>(i) Consolidated Statements of Income;</li><li>(ii) Consolidated Balance Sheets;</li><li>(iii) Consolidated Statements of Cash Flows; and</li><li>(iv) Related notes.</li></ul> |

## RESTRICTED STOCK UNIT AWARD AGREEMENT

This Agreement is entered into as of February \_\_, 2017, between Northwest Natural Gas Company, an Oregon corporation (the "Company"), and \_\_\_\_\_ ("Recipient").

On February \_\_, 2017, the Organization and Executive Compensation Committee (the "Committee") of the Company's Board of Directors (the "Board") awarded restricted stock units to Recipient with a performance threshold intended to qualify the award as a performance-based award pursuant to Section 8 of the Company's Long Term Incentive Plan (the "Plan"). Compensation paid pursuant to the restricted stock units is intended to qualify as performance-based compensation under Section 162(m) of the Internal Revenue Code of 1986 (the "Code"). Recipient desires to accept the award subject to the terms and conditions of this Agreement.

NOW, THEREFORE, the parties agree as follows:

1. Grant of Restricted Stock Units; Dividend Equivalents. Subject to the terms and conditions of this Agreement, the Company hereby grants to the Recipient \_\_\_\_\_ restricted stock units (the "RSUs"). The grant of RSUs obligates the Company, upon vesting in accordance with this Agreement, to deliver to the Recipient one share of Common Stock of the Company (a "Share") for each RSU. Upon vesting of each RSU, the Company also agrees to make a dividend equivalent cash payment with respect to each vested RSU in an amount equal to the total amount of dividends paid per share of Company Common Stock for which the dividend record dates occurred after the date of this Agreement and before the date of delivery of the underlying Shares. The RSUs are subject to forfeiture as set forth in Sections 2.1 and 2.10 below.

2. Vesting; Forfeiture Restriction.

2.1 Vesting Schedule.

(a) All of the RSUs shall initially be unvested. Subject to Sections 2.3, 2.4, 2.5, 2.10 and 5.2, the RSUs shall vest as follows:

- (1) one-fourth of the RSUs shall vest on March 1, 2018 if the Performance Threshold (as defined in Section 2.2 below) is satisfied for 2017;
- (2) an additional one-fourth of the RSUs shall vest on March 1, 2019 if the Performance Threshold is satisfied for 2018;
- (3) an additional one-fourth of the RSUs shall vest on March 1, 2020 if the Performance Threshold is satisfied for 2019; and
- (4) the final one-fourth of the RSUs shall vest on March 1, 2021 if the Performance Threshold is satisfied for 2020.

(b) If the Performance Threshold is not satisfied for any year set forth in (1), (2), (3) or (4) above, the RSUs that would have vested if the Performance Threshold had been satisfied for that year (the "Performance Year") shall be forfeited to the Company effective as of the last day of the Performance Year. For example, if the Performance Threshold is not satisfied for 2017, all RSUs that were scheduled to vest on March 1, 2018 shall be forfeited effective as of December 31, 2017.

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(c) If a Change in Control (as defined in Section 2.6 below) occurs, the Performance Threshold shall be deemed to be satisfied for all Performance Years that were not completed prior to the Change in Control, with the effect that the RSUs outstanding at the time of the Change of Control shall vest upon completion of the applicable time periods in Section 2.1(a).

## 2.2 Performance Threshold.

(a) For purposes of this Agreement, the “Performance Threshold” for any year shall be satisfied if the ROE (as defined below) for that year is greater than the 5 Yr Avg Cost of LT Debt (as defined below) for that year.

(b) The “ROE” for any year shall be calculated by dividing the Company’s Adjusted Net Income (as defined below) for the year by the Average Equity (as defined below) for the year. Subject to adjustment in accordance with Section 2.2(c) below, the Company’s “Adjusted Net Income” for any year shall be equal to the Company’s net income attributable to common shareholders for the year, as set forth in the audited consolidated statement of income of the Company and its subsidiaries for the year. Subject to adjustment in accordance with Section 2.2(c) below, “Average Equity” for any year shall mean the average of the Company’s total common stock equity as of the last day of the year and the Company’s total common stock equity as of the last day of the prior year, in each case as set forth on the audited consolidated balance sheet of the Company and its subsidiaries as of the applicable date.

(c) The following adjustments shall be made in the calculation of ROE, if applicable:

(1) Change in Accounting Principle. If the Company implements a change in accounting principle before the completion of all Performance Years either as a result of the issuance of new accounting standards or otherwise, and the effect of the accounting change was not reflected in the Company’s business plan at the time of award of the RSUs, then ROE for each affected year shall be adjusted to eliminate the impact of the change in accounting principle.

(2) Gain or Loss on Sale of Business. Adjusted Net Income for each Performance Year shall be adjusted to eliminate any gain or loss on the disposition of any subsidiary, division or business during the year, as set forth in the audited consolidated financial statements of the Company and its subsidiaries for that year.

(3) Impairments. Adjusted Net Income for each Performance Year shall be adjusted to eliminate any charges taken by the Company during the year for impairment of assets (excluding utility plant assets), that exceed \$500,000 for any single impaired asset.

(4) Tax Impacts. All adjustments for the items listed in Sections 2.2(c)(1) to 2.2(c)(3) in any year shall be net of income taxes based on the Company’s consolidated effective tax rate for the year.

(5) Tax Changes. Adjusted Net Income for each Performance Year shall be adjusted to eliminate any positive or negative impacts on earnings resulting from changes to federal, state or local income tax rates or the imposition of a new tax during the period between the award of the RSUs and the completion of all Performance Years, and any resulting impact on deferred tax account balances.

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(d) The “5 Yr Avg Cost of LT Debt” for any year shall mean the average of five numbers consisting of the Avg Cost of LT Debt (as defined below) for that year and for each of the four preceding years. The “Avg Cost of LT Debt” for any year shall be equal to the sum of the Weighted Costs (as defined below) calculated for each series or tranche of long-term debt of the Company outstanding on the last day of the year. The “Weighted Cost” for a series or tranche of long-term debt as of any date shall be calculated by multiplying the Effective Interest Rate (as defined below) on the debt as of that date by the outstanding principal balance of the debt on that date, and then dividing the resulting amount by the Company’s total outstanding principal balance of long-term debt as of that date. The “Effective Interest Rate” for a series or tranche of long-term debt as of any date shall be the yield calculated based on the settlement date for the original issuance of the series or tranche, the maturity date of the series or tranche, the stated annual interest rate of the series or tranche in effect on that date, the number of interest payments per year under the terms of the series or tranche, the initial borrowing of an amount equal to the principal balance net of Debt Issuance Costs (as defined below) for the series or tranche, and the repayment of principal at maturity or otherwise according to the terms of the series or tranche. The “Debt Issuance Costs” for a series or tranche of long-term debt shall include the fees, commissions and expenses of issuance of such debt, any other purchase discount from the face amount of such debt, and any premiums, write-offs of unamortized debt issuance costs and other costs incurred in connection with retiring debt refinanced with the proceeds of such debt, all as reflected in the Company’s accounting records. For purposes of this Section 2.2(d), the Company’s long term debt and the interest rates and outstanding principal balances of the outstanding series or tranches of long-term debt as of any date shall be those amounts as set forth in the audited consolidated financial statements of the Company and its subsidiaries for the year ending on that date, and shall in all cases include the current portion of any long-term debt and exclude borrowings under a revolving credit facility. For the avoidance of doubt, the Effective Interest Rate for purposes of this Agreement of each series of fixed-rate long-term debt outstanding as of the date of this Agreement is set forth on Exhibit A hereto.

### 2.3 Effect of Retirement, Death, or Disability.

(a) If Recipient’s employment by the Company terminates because of Retirement (as defined below), death or physical disability (within the meaning of Section 22(e)(3) of the Code and a Change in Control has not previously occurred, all outstanding RSUs shall remain outstanding and subject to potential future vesting upon satisfaction of the Performance Threshold for the applicable years.

(b) If Recipient’s employment by the Company terminates because of Retirement, death or physical disability and a Change in Control subsequently occurs, all outstanding RSUs shall immediately vest. If a Change in Control occurs and Recipient’s employment by the Company subsequently terminates because of Retirement, death or physical disability, all outstanding RSUs shall immediately vest.

(c) The term “Retirement” means termination of employment (1) on or after the first anniversary of the date of this Agreement, and (2) after the Recipient is (i) age 62 with at least five years of service as an employee of the Company, or (ii) age 55 with age plus years of service (including fractions) as an employee of the Company totaling at least 70; provided, however, that a termination of Recipient’s employment by the Company for Cause (as defined in Section 2.8 below) shall not constitute a Retirement.

2.4 CIC Acceleration if Party to a Severance Agreement. If Recipient is a party to a Change in Control Severance Agreement with the Company, all outstanding RSUs shall immediately vest

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if Recipient becomes entitled to a Change in Control Severance Benefit (as defined below). A “Change in Control Severance Benefit” means the severance benefit provided for in Recipient’s Change in Control Severance Agreement with the Company; provided, however, that such severance benefit is a “Change in Control Severance Benefit” for purposes of this Agreement only if, under the terms of Recipient’s Change in Control Severance Agreement, Recipient becomes entitled to the severance benefit (a) after a change in control of the Company has occurred, (b) because Recipient’s employment with the Company has been terminated by Recipient for good reason in accordance with the terms and conditions of the Change in Control Severance Agreement or by the Company other than for cause, and (c) because Recipient has satisfied any other conditions or requirements specified in the Change in Control Severance Agreement and necessary for Recipient to become entitled to receive the severance benefit. For purposes of this Section 2.4, the terms “change in control,” “good reason,” “cause” and “disability” shall have the meanings set forth in Recipient’s Change in Control Severance Agreement.

2.5 CIC Acceleration if Not a Party to a Severance Agreement. If Recipient is not a party to a Change in Control Severance Agreement with the Company, all outstanding RSUs shall immediately vest if a Change in Control (as defined in Section 2.6 below) occurs and at any time after the earlier of Shareholder Approval (as defined in Section 2.7 below), if any, or the Change in Control and on or before the second anniversary of the Change in Control, (a) Recipient’s employment is terminated by the Company (or its successor) without Cause (as defined in Section 2.8 below), or (b) Recipient’s employment is terminated by Recipient for Good Reason (as defined in Section 2.9 below).

2.6 Change in Control. For purposes of this Agreement, a “Change in Control” of the Company shall mean the occurrence of any of the following events:

(a) The consummation of:

(1) any consolidation, merger or plan of share exchange involving the Company (a “Merger”) as a result of which the holders of outstanding securities of the Company ordinarily having the right to vote for the election of directors (“Voting Securities”) immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger; or

(2) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company;

(b) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted the Board (“Incumbent Directors”) shall cease for any reason to constitute at least a majority thereof; provided, however, that the term “Incumbent Director” shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(c) Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934, other than the Company or any employee benefit plan sponsored by the Company) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than the Company, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities.

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2.7 Shareholder Approval. For purposes of this Agreement, “Shareholder Approval” shall be deemed to have occurred if the shareholders of the Company approve an agreement entered into by the Company, the consummation of which would result in the occurrence of a Change in Control.

2.8 Cause. For purposes of this Agreement, “Cause” shall mean (a) the willful and continued failure by Recipient to perform substantially Recipient’s assigned duties with the Company (other than any such failure resulting from incapacity due to physical or mental illness) after a demand for substantial performance is delivered to Recipient by the Company which specifically identifies the manner in which Recipient has not substantially performed such duties, (b) willful commission by Recipient of an act of fraud or dishonesty resulting in economic or financial injury to the Company, (c) willful misconduct by Recipient that substantially impairs the Company’s business or reputation, or (d) willful gross negligence by Recipient in the performance of his or her duties.

2.9 Good Reason. For purposes of this Agreement, “Good Reason” shall mean the occurrence after Shareholder Approval, if applicable, or the Change in Control, of any of the following circumstances, but only if (x) Recipient gives notice to the Company of Recipient’s intent to terminate employment for Good Reason within 30 days after the later of (1) notice to Recipient of such circumstances, or (2) the Change in Control, and (y) such circumstances are not fully corrected by the Company within 90 days after Recipient’s notice:

(a) the assignment to Recipient of a different title, job or responsibilities that results in a decrease in the level of Recipient’s responsibility; provided that Good Reason shall not exist if Recipient continues to have the same or a greater general level of responsibility for the former Company operations after the Change in Control as Recipient had prior to the Change in Control even though such responsibilities have necessarily changed due to the former Company operations becoming a subsidiary or division of the surviving company;

(b) a reduction by the Company in Recipient’s base salary as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(c) the failure by the Company to continue in effect any employee benefit or incentive plan in which Recipient is participating immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control (or plans providing Recipient with at least substantially similar benefits) other than as a result of the normal expiration of any such plan in accordance with its terms as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control, or the taking of any action, or the failure to act, by the Company which would adversely affect Recipient’s continued participation in any of such plans on at least as favorable a basis to Recipient as is the case immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control or which would materially reduce Recipient’s benefits in the future under any of such plans or deprive Recipient of any material benefit enjoyed by Recipient immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control;

(d) the failure by the Company to provide and credit Recipient with the number of paid vacation days to which Recipient is then entitled in accordance with the Company’s normal vacation policy as in effect immediately prior to the earlier of Shareholder Approval, if applicable, or the Change in Control; or

(e) the Company’s requiring Recipient to be based more than 30 miles from where Recipient’s office is located immediately prior to the earlier of Shareholder Approval, if applicable,

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or the Change in Control except for required travel on the Company's business to an extent substantially consistent with the business travel obligations which Recipient undertook on behalf of the Company prior to the earlier of Shareholder Approval, if applicable, or the Change in Control.

2.10 Forfeiture; Possible Restoration. If Recipient ceases to be employed by the Company for any reason or for no reason, with or without cause, other than because of Retirement, death or physical disability (within the meaning of Section 22(e)(3) of the Code), any RSUs that did not vest pursuant to this Section 2 or Section 5.2 at or prior to the time of such termination of employment shall be forfeited to the Company; provided, however, that if Recipient's employment is terminated by the Company without Cause or by the Recipient for Good Reason after Shareholder Approval but before a Change in Control, any RSUs that are forfeited under this sentence shall be restored to the Recipient and vested if a Change in Control subsequently occurs within two years.

3. Certification and Delivery. As soon as practicable following the completion of each Performance Year, the Company shall calculate the ROE and the 5 Yr Avg Cost of LT Debt for that Performance Year, and shall submit those calculations to the Committee. At or prior to the regularly scheduled meeting of the Committee held in February of the year immediately following each Performance Year (each, a "Certification Meeting"), the Committee shall certify in writing (which may consist of approved minutes of the meeting) the levels of ROE and 5 Yr Avg Cost of LT Debt attained by the Company for that Performance Year, and whether or not the Performance Threshold was satisfied for that Performance Year. Unless otherwise required under this Agreement as a result of the occurrence of a Change in Control, no amounts shall be delivered or paid unless the Committee certifies that the Performance Threshold has been satisfied for the applicable Performance Year. Subject to applicable tax withholding, on a date (a "Payment Date") that is on or as soon as practicable after the date any of the RSUs become vested or, if later, five business days following the Certification Meeting relating to those RSUs, the Company shall deliver to Recipient (a) the number of Shares underlying the RSUs that vested (rounded down to the nearest whole share), and (b) the dividend equivalent cash payment determined under Section 1 with respect to the number of Shares that are delivered; provided, however, that if accelerated vesting of the RSUs occurs pursuant to Section 2.3(b) as a result of Recipient's Retirement after a Change in Control has previously occurred, the Payment Date shall be delayed until a date that is on or as soon as practicable after the earlier of (x) the date the RSUs would have vested under Section 2.1, or (y) the date that is six months after Recipient's separation from service (within the meaning of Section 409A of the Internal Revenue Code). Notwithstanding the foregoing provisions of this Section 3, if Recipient shall have made a valid election to defer receipt of the Shares and dividend equivalent cash payment pursuant to the terms of the Company's Deferred Compensation Plan for Directors and Executives (the "DCP"), payment of RSUs that vest shall be made in accordance with that election.

#### 4. Tax Withholding.

4.1 Recipient acknowledges that, on any Payment Date when Shares are delivered to Recipient, the Value (as defined below) on that date of the Shares so delivered (as well as the amount of the related dividend equivalent cash payment) will be treated as ordinary compensation income for federal and state income and FICA tax purposes, and that the Company will be required to withhold taxes on these income amounts. To satisfy the required withholding amount, the Company shall first withhold all or part of the dividend equivalent cash payment, and if that is insufficient, the Company shall withhold the number of Shares having a Value equal to the remaining withholding amount. For purposes of this Section 4, the "Value" of a Share shall be equal to the closing market price for Company Common Stock on the last trading day preceding the Payment Date.

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4.2 Recipient acknowledges that under current tax law, the Company is required to withhold FICA taxes with respect to the RSUs at the earlier of (a) the issuance of shares underlying the RSUs or (b) the date after a Change in Control on which Recipient becomes eligible for Retirement (or the date of the Change in Control if Recipient is eligible for Retirement at the time of the Change in Control). To satisfy the required minimum FICA withholding in the event that subsection (b) applies, Recipient shall, immediately upon notification of the amount due, pay to the Company in cash or by check amounts necessary to satisfy applicable FICA withholding requirements. If Recipient fails to pay the amount demanded, the Company may withhold that amount from other amounts payable to Recipient, including salary, subject to applicable law.

4.3 Notwithstanding the foregoing, Recipient may elect not to have Shares withheld to cover taxes by giving notice to the Company in writing prior to the Payment Date, in which case the Shares shall be issued or acquired in Recipient's name on the Payment Date thereby triggering the tax consequences, but the Company shall retain the certificate for the Shares as security until Recipient shall have paid to the Company in cash any required tax withholding not covered by withholding of the dividend equivalent cash payment.

5. Sale of the Company. If there shall occur a merger, consolidation or plan of exchange involving the Company pursuant to which the outstanding shares of Common Stock of the Company are converted into cash or other stock, securities or property, or a sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company, then either:

5.1 the unvested RSUs shall be converted into restricted stock units for stock of the surviving or acquiring corporation in the applicable transaction, with the amount and type of shares subject thereto to be conclusively determined by the Committee, taking into account the relative values of the companies involved in the applicable transaction and the exchange rate, if any, used in determining shares of the surviving corporation to be held by the former holders of the Company's Common Stock following the applicable transaction, and disregarding fractional shares; or

5.2 all of the unvested RSUs shall immediately vest and the underlying Shares and related dividend equivalent cash payment shall be delivered simultaneously with the closing of the applicable transaction such that Recipient will participate as a shareholder in receiving proceeds from such transaction with respect to those Shares.

6. Changes in Capital Structure.

6.1 If, prior to the full vesting of all of the RSUs granted under this Agreement, the outstanding Common Stock of the Company is increased or decreased or changed into or exchanged for a different number or kind of shares or other securities of the Company by reason of any stock split, combination of shares or dividend payable in shares, recapitalization or reclassification, appropriate adjustment shall be made by the Committee in the number and kind of shares subject to the unvested RSUs so that Recipient's proportionate interest before and after the occurrence of the event is maintained. Notwithstanding the foregoing, the Committee shall have no obligation to effect any adjustment that would or might result in the issuance of fractional shares, and any fractional shares resulting from any adjustment may be disregarded or provided for in any manner determined by the Committee. Any such adjustments made by the Committee shall be conclusive.

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6.2 If the outstanding Common Stock of the Company is hereafter converted into or exchanged for all of the outstanding Common Stock of a corporation (the “Parent Successor”) as part of a transaction (the “Transaction”) in which the Company becomes a wholly-owned subsidiary of Parent Successor, then (a) the obligations under this Agreement shall be assumed by Parent Successor and references in this Agreement to the Company shall thereafter generally be deemed to refer to Parent Successor, (b) Common Stock of Parent Successor shall be issued in lieu of Common Stock of the Company under this Agreement, (c) the performance measured by the Performance Threshold shall be the continuous performance of the Company prior to the Transaction and Parent Successor after the Transaction, (d) employment by the Company for purposes of Section 2 of this Agreement shall include employment by either the Company or Parent Successor, and (e) the dividend equivalent cash payments under this Agreement shall be based on dividends paid on the Common Stock of the Company prior to the Transaction and Parent Successor after the Transaction.

7. Recoupment On Misconduct.

7.1 If at any time before a Change in Control and within three years after any date on which any RSUs vested, (a) the Company’s financial statements for the corresponding Performance Year are the subject of a restatement due to the Misconduct (as defined below) of any person (whether or not Recipient was personally involved in such Misconduct), and (b) based on the Company’s financial statements as restated, the Performance Threshold was not satisfied for that Performance Year, then Recipient shall repay to the Company the Shares (the “Excess Shares”) and dividend equivalent cash payment (the “Excess Dividends”) that vested under this Agreement on that vesting date. If any Excess Shares are sold by Recipient prior to the Company’s demand for repayment (including any shares withheld for taxes under Section 4 of this Agreement), Recipient shall repay to the Company 100% of the proceeds of such sale or sales. The Committee may, in its sole discretion, reduce the amount to be repaid by Recipient to take into account the tax consequences of such repayment for Recipient.

7.2 If the Committee determines that Recipient engaged in any Misconduct after the date of this Agreement and prior to a sale of any of the Shares (the “Tainted Shares”), and this determination is made before a Change in Control and within three years after the vesting of the Tainted Shares, Recipient shall repay to the Company the Excess Proceeds (as defined below). The Committee may, in its sole discretion, reduce the amount of Excess Proceeds to be repaid by Recipient to take into account the tax consequences of such repayment or any other factors. The return of Excess Proceeds is in addition to and separate from any other relief available to the Company due to Recipient’s Misconduct.

7.3 “Misconduct” shall mean (a) willful commission of an act of fraud or dishonesty resulting in economic or financial injury to the Company, (b) willful misconduct that substantially impairs the Company’s business or reputation, or (c) willful gross negligence in the performance of the person’s duties; provided, however, that such acts shall only constitute Misconduct if the Committee determines that such acts contributed to an obligation to restate the Company’s financial statements for any quarter or year or otherwise had (or will have when publicly disclosed) an adverse impact on the market price of the Company Common Stock.

7.4 “Excess Proceeds” shall mean the excess of (a) the actual aggregate sales proceeds from Recipient’s sales of Tainted Shares, over (b) the aggregate sales proceeds Recipient would have received from sales of Tainted Shares at a price per share determined appropriate by the Committee in its discretion to reflect what the market price of the Company Common Stock would have been if the restatement had occurred or other Misconduct had been disclosed prior to such sales.

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7.5 If any portion of the Excess Shares and Excess Dividends was deferred under the DCP, that portion shall be recovered by canceling the amounts so deferred under the DCP and any dividends or other earnings credited under the DCP with respect to such cancelled amounts. The Company may seek direct repayment from Recipient of any Excess Shares, Excess Dividends and Excess Proceeds not so recovered and may, to the extent permitted by applicable law, offset such amounts against any compensation or other amounts owed by the Company to Recipient. In particular, such amounts may be recovered by offset against the after-tax proceeds of deferred compensation payouts under the DCP, the Company's Executive Supplemental Retirement Income Plan or the Company's Supplemental Executive Retirement Plan at the times such deferred compensation payouts occur under the terms of those plans. Amounts that remain unpaid for more than 60 days after demand by the Company shall accrue interest at the rate used from time to time for crediting interest under the DCP.

8. Approvals. The issuance by the Company of authorized and unissued shares or reacquired shares under this Agreement is subject to the approval of the Oregon Public Utility Commission and the Washington Utilities and Transportation Commission, but no such approvals shall be required for the purchase of shares on the open market for delivery to Recipient in satisfaction of its obligations under this Agreement. The obligations of the Company under this Agreement are otherwise subject to the approval of state and federal authorities or agencies with jurisdiction in the matter. The Company will use its best efforts to take steps required by state or federal law or applicable regulations, including rules and regulations of the Securities and Exchange Commission and any stock exchange on which the Company's shares may then be listed, in connection with the award under this Agreement. The foregoing notwithstanding, the Company shall not be obligated to issue or deliver Common Stock under this Agreement if such issuance or delivery would violate applicable state or federal law.

9. No Right to Employment. Nothing contained in this Agreement shall confer upon Recipient any right to be employed by the Company or to continue to provide services to the Company or to interfere in any way with the right of the Company to terminate Recipient's services at any time for any reason, with or without cause.

10. Miscellaneous.

10.1 Entire Agreement; Amendment. This Agreement constitutes the entire agreement of the parties with regard to the subjects hereof and may be amended only by written agreement between the Company and Recipient.

10.2 Notices. Any notice required or permitted under this Agreement shall be in writing and shall be deemed sufficient when delivered personally to the party to whom it is addressed or when deposited into the United States Mail as registered or certified mail, return receipt requested, postage prepaid, addressed to the Company, Attention: Corporate Secretary, at its principal executive offices or to Recipient at the address of Recipient in the Company's records, or at such other address as such party may designate by ten (10) days' advance written notice to the other party.

10.3 Assignment; Rights and Benefits. Recipient shall not assign this Agreement or any rights hereunder to any other party or parties without the prior written consent of the Company. The rights and benefits of this Agreement shall inure to the benefit of and be enforceable by the Company's successors and assigns and, subject to the foregoing restriction on assignment, be binding upon Recipient's heirs, executors, administrators, successors and assigns.

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10.4 Further Action. The parties agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of this Agreement.

10.5 Applicable Law; Attorneys' Fees. The terms and conditions of this Agreement shall be governed by the laws of the State of Oregon. In the event either party institutes litigation hereunder, the prevailing party shall be entitled to reasonable attorneys' fees to be set by the trial court and, upon any appeal, the appellate court.

10.6 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

NORTHWEST NATURAL GAS COMPANY

By \_\_\_\_\_

Title SVP and Chief Administrative Officer

RECIPIENT

\_\_\_\_\_

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## EFFECTIVE INTEREST RATES OF OUTSTANDING FIXED-RATE LONG-TERM DEBT

The outstanding series or tranches of fixed-rate long-term debt of the Company outstanding as of the date of this Agreement and the Effective Interest Rate of each such series or tranche are as follows:

| <u>Series</u>            | <u>Effective Interest Rate</u> |
|--------------------------|--------------------------------|
| 7.00 % Series B due 2017 | 7.089%                         |
| 6.60 % Series B due 2018 | 7.181%                         |
| 8.31 % Series B due 2019 | 9.479%                         |
| 7.63 % Series B due 2019 | 7.727%                         |
| 5.37 % Series B due 2020 | 7.327%                         |
| 9.05 % Series A due 2021 | 9.163%                         |
| 3.176% Series B due 2021 | 3.319%                         |
| 3.542% Series B due 2023 | 3.696%                         |
| 5.62 % Series B due 2023 | 6.360%                         |
| 7.72 % Series B due 2025 | 8.336%                         |
| 6.52 % Series B due 2025 | 6.589%                         |
| 7.05 % Series B due 2026 | 7.121%                         |
| 7.00 % Series B due 2027 | 7.062%                         |
| 6.65 % Series B due 2027 | 6.714%                         |
| 6.65 % Series B due 2028 | 6.727%                         |
| 7.74 % Series B due 2030 | 8.433%                         |
| 7.85 % Series B due 2030 | 8.551%                         |
| 5.82 % Series B due 2032 | 5.913%                         |
| 5.66 % Series B due 2033 | 5.723%                         |
| 5.25 % Series B due 2035 | 5.316%                         |
| 4.00 % Series B due 2042 | 4.059%                         |

# NORTHWEST NATURAL GAS COMPANY

## Ratios of Earnings to Fixed Charges

(Unaudited)

|                                              | Year Ended December 31, |            |            |            |            | Twelve<br>Months<br>Ended<br>March 31, | Three<br>Months<br>Ended<br>March 31, |
|----------------------------------------------|-------------------------|------------|------------|------------|------------|----------------------------------------|---------------------------------------|
| <i>In thousands, except share data</i>       | 2016                    | 2015       | 2014       | 2013       | 2012       | 2017                                   | 2017                                  |
| Fixed Charges, as defined:                   |                         |            |            |            |            |                                        |                                       |
| Interest on Long-Term Debt                   | \$ 34,508               | \$ 37,918  | \$ 40,066  | \$ 40,825  | \$ 39,175  | \$ 35,170                              | \$ 9,234                              |
| Other Interest                               | 3,404                   | 3,173      | 2,718      | 2,709      | 2,314      | 3,081                                  | 533                                   |
| Amortization of Debt<br>Discount and Expense | 1,671                   | 1,760      | 1,963      | 1,877      | 1,848      | 1,761                                  | 501                                   |
| Interest Portion of Rentals                  | 2,048                   | 1,976      | 2,302      | 1,910      | 1,864      | 2,333                                  | 750                                   |
| Total Fixed Charges, as<br>defined           | 41,631                  | 44,827     | 47,049     | 47,321     | 45,201     | 42,345                                 | 11,018                                |
| Earnings, as defined:                        |                         |            |            |            |            |                                        |                                       |
| Net Income                                   | 58,895                  | 53,703     | 58,692     | 60,538     | 58,779     | 62,564                                 | 40,310                                |
| Taxes on Income                              | 40,714                  | 35,753     | 41,643     | 41,705     | 43,403     | 42,251                                 | 26,923                                |
| Fixed Charges, as above                      | 41,631                  | 44,827     | 47,049     | 47,321     | 45,201     | 42,345                                 | 11,018                                |
| Total Earnings, as defined                   | \$ 141,240              | \$ 134,283 | \$ 147,384 | \$ 149,564 | \$ 147,383 | \$ 147,160                             | \$ 78,251                             |
| Ratios of Earnings to Fixed<br>Charges       | 3.39                    | 3.00       | 3.13       | 3.16       | 3.26       | 3.48                                   | 7.10                                  |

**CERTIFICATION**

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I, David H. Anderson, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarterly period ended March 31, 2017 of Northwest Natural Gas Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 8, 2017

/s/ David H. Anderson

David H. Anderson  
Chief Executive Officer

**CERTIFICATION**

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I, Brody J. Wilson, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarterly period ended March 31, 2017 of Northwest Natural Gas Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 8, 2017

/s/ Brody J. Wilson

Brody J. Wilson

Chief Financial Officer, Treasurer, Chief Accounting Officer and Controller

## NORTHWEST NATURAL GAS COMPANY

Certificate Pursuant to Section 906  
of Sarbanes – Oxley Act of 2002

Each of the undersigned, DAVID H. ANDERSON, Chief Executive Officer, and BRODY J. WILSON, the Chief Financial Officer, Treasurer, Chief Accounting Officer and Controller of NORTHWEST NATURAL GAS COMPANY (the Company), DOES HEREBY CERTIFY that:

1. The Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 (the Report) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, each of the undersigned has caused this instrument to be executed this 8th day of May 2017.

/s/ David H. Anderson  
David H. Anderson  
Chief Executive Officer

/s/ Brody J. Wilson  
Brody J. Wilson  
Chief Financial Officer,  
Treasurer,  
Chief Accounting Officer, and  
Controller

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to Northwest Natural Gas Company and will be retained by Northwest Natural Gas Company and furnished to the Securities and Exchange Commission or its staff upon request.