NORTHWEST NATURAL GAS CO
Form 10-K
February 27, 2017
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ___________ to____________
Commission file number 1-15973

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

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [X] No [ ]
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes [ ] No [X]
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [X] No [ ]
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
[ ]
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer [X]   Accelerated Filer [ ]
Non-accelerated Filer [ ]   Smaller Reporting Company [ ]

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

As of June 30, 2016, the aggregate market value of the shares of Common Stock (based upon the closing price of these shares on the New York Stock Exchange on that date) held by non-affiliates was $1,761,871,513.

At February 17, 2017, 28,630,327 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement of the registrant, to be filed in connection with the 2017 Annual Meeting of Shareholders, are incorporated by reference in Part III.

NORTHWEST NATURAL GAS COMPANY
Annual Report to Securities and Exchange Commission on Form 10-K
For the Fiscal Year Ended December 31, 2016

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GLOSSARY OF TERMS AND ABBREVIATIONS

AFUDC	Allowance for Funds Used During Construction
AOCI / AOCL	Accumulated Other Comprehensive Income (Loss)
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
Average Weather	The 25-year average of heating degree days based on temperatures established in our last Oregon general rate case
Bcf	Billion cubic feet, a volumetric measure of natural gas, where one Bcf is roughly equal to 10 million therms
Btu	British thermal unit, a basic unit of thermal energy measurement; one Btu equals the energy required to raise one pound of water one degree Fahrenheit at an atmospheric pressure of one and 60 degrees Fahrenheit. One hundred thousand Btu's equal one therm
CAP	Compliance Assurance Process with the Internal Revenue Service
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
Core Utility Customers	Residential, commercial and industrial customers receiving firm service from the utility
Cost of Gas	The delivered cost of natural gas sold to customers, including the cost of gas purchased or withdrawn/produced from storage inventory or reserves, gains and losses from gas commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and Company gas use
CPUC	California Public Utilities Commission, the entity that regulates our California gas storage business at our Gill Ranch facility with respect to rates and terms of service, among other matters
Decoupling	A billing rate mechanism, also referred to as our conservation tariff, which is designed to break the link between utility earnings and the quantity of natural gas sold to customers; the design is intended to allow the utility to encourage industrial and small commercial customers to conserve energy while not adversely affecting its earnings due to reductions in sales volumes
Demand Cost	A component in core utility customer rates representing the cost of securing firm pipeline capacity, whether the capacity is used or not
Dth	Dekatherm (also decatherm) is equal to 10 therms or one million British thermal units (Btu)
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP financial measure
EE/CA	Engineering Evaluation / Cost Analysis
Encana	Encana Oil & Gas (USA) Inc.
Energy Corp	Northwest Energy Corporation, a wholly-owned subsidiary of NW Natural
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission; the entity regulating interstate storage services offered by our Mist gas storage facility as part of our gas storage segment
Firm Service	Natural gas service offered to customers under contracts or rate schedules that will not be disrupted to meet the needs of other customers
FMBs	First Mortgage Bonds
GAAP	Accounting principles generally accepted in the United States of America
	A periodic filing with state or federal regulators to establish billing rates for utility customers

General Rate Case	
GHG	Greenhouse gases
Gill Ranch	Gill Ranch Storage, LLC, a wholly-owned subsidiary of NWN Gas Storage
Gill Ranch Facility	Underground natural gas storage facility near Fresno, California, with 75% owned by Gill Ranch and 25% owned by PG&E

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GTN	Gas Transmission Northwest, which owns a transmission pipeline serving California and the Pacific Northwest
Heating Degree Days	Units of measure reflecting temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day’s high and low temperatures from 65 degrees Fahrenheit
HATFA	Highway and Transportation Funding Act of 2014
IBEW	International Brotherhood of Electrical Workers Local Union No. 1245, which is also referred to as the Union representing NW Natural's bargaining unit employees at Gill Ranch
Interruptible Service	Natural gas service offered to customers (usually large commercial or industrial users) under contracts or rate schedules that allow for interruptions when necessary to meet the needs of firm service customers
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
KB	Kelso-Beaver Pipeline, of which 10% is owned by KB Pipeline Company, a subsidiary of NNG Financial
LNG	Liquefied Natural Gas, the cryogenic liquid form of natural gas. To reach a liquid form at atmospheric pressure, natural gas must be cooled to approximately negative 260 degrees Fahrenheit
LWG	Lower Willamette Group
MAP-21	A federal pension plan funding law called the Moving Ahead for Progress in the 21st Century Act, July 2012
Moody's	Moody's Investors Service, Inc. is a credit rating agency
NAV	Net Asset Value
NNG Financial	NNG Financial Corporation, a wholly-owned subsidiary of NW Natural
NOL	Net Operating Loss
NRD	Natural Resource Damages
NWN Energy	NW Natural Energy, LLC, a wholly-owned subsidiary of NW Natural
NWN Gas Reserves	NWN Gas Reserves LLC, a wholly-owned subsidiary of Northwest Energy Corporation
NWN Gas Storage	NW Natural Gas Storage, LLC, a wholly-owned subsidiary of NWN Energy
ODEQ	Oregon Department of Environmental Quality
OPEIU	Office and Professional Employees International Union Local No. 11, AFL-CIO, which is also referred to as the Union representing NW Natural's bargaining unit employees, other than those employees in the process of unionizing at Gill Ranch
OPUC	Public Utility Commission of Oregon; the entity that regulates our Oregon utility business with respect to rates and terms of service, among other matters; the OPUC also regulates our Mist gas storage facility's intrastate storage services
PBGC	Pension Benefit Guaranty Corporation
PG&E	Pacific Gas & Electric Company; is a 25% owner of the Gill Ranch Facility
PGA	Purchased Gas Adjustment, a regulatory mechanism which adjusts customer rates to reflect changes in the forecasted cost of gas and differences between forecasted and actual gas costs from the prior year
PGE	Portland General Electric; primary customer of the North Mist gas storage expansion
PHMSA	U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration

PRP	Potentially Responsible Parties
RI/FS	Remedial Investigation / Feasibility Study
ROD	Record of Decision
ROE	Return on Equity, a measure of corporate profitability, calculated as net income divided by average common stock equity. Authorized ROE refers to the equity rate approved by a regulatory agency for use in determining utility revenue requirements
ROR	Rate of Return, a measure of return on utility rate base. Authorized ROR refers to the rate of return approved by a regulatory agency and is generally discussed in the context of ROE and capital structure.
S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc., is a credit rating agency

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Sales Service	Service provided whereby a customer purchases both natural gas commodity supply and transportation from the utility
SEC	U.S. Securities and Exchange Commission
SIP	System Integrity Program, an Oregon billing rate mechanism that provides cost recovery of pipeline system integrity programs, which are required under various safety standards prescribed by both state and federal regulators
SRRM	Site Remediation and Recovery Mechanism, a billing rate mechanism for recovering prudently incurred environmental site remediation costs allocable to Oregon through customer billings, subject to an earnings test
TAIL	TransCanada American Investments, Ltd., a 50% owner of TWH
Therm	The basic unit of natural gas measurement, equal to one hundred thousand Btu’s
TWH	Trail West Holdings, LLC is 50% owned by NWN Energy
TWP	Trail West Pipeline, LLC, a subsidiary of TWH
TransCanada	TransCanada Pipelines Limited, owner of TAIL and GTN
Transportation Service	Service provided whereby a customer purchases natural gas directly from a supplier but pays the utility to transport the gas over its distribution system to the customer’s facility
Utility Margin	A financial measure consisting of utility operating revenues less the associated cost of gas, franchise tax and environmental recoveries
VIE	Variable Interest Entity
WARM	An Oregon billing rate mechanism applied to residential and commercial customers to adjust for temperature variances from average weather; rates decrease when the weather is colder than average, and rates increase when the weather is warmer than average; the mechanism is applied to customer bills from December through mid-May of each heating season
WUTC	Washington Utilities and Transportation Commission, the entity that regulates our Washington utility business with respect to rates and terms of service, among other matters

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FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, 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 and predictions;
- objectives;
- goals;
- strategies;
- assumptions, generalizations and estimates;
- ongoing continuation of past practices or patterns;
- future events or performance;
- trends;
- risks;
- timing and cyclicality;
- earnings and dividends;
- capital expenditures and allocation;
- capital or organizational structure;
- climate change and our role in a low-carbon future;
- growth;
- customer rates;
- labor relations;
- workforce succession;
- commodity costs;
- gas reserves;
- operational performance and costs;
- energy policy, infrastructure and preferences;
- efficacy of derivatives and hedges;
- liquidity and financial positions;
- valuations;
- project and program development, expansion, or investment;
- pipeline capacity, demand, location, and reliability;
- adequacy of property rights;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- rate or regulatory outcomes, recovery or refunds;
- impacts or changes of laws, rules and regulations;
- tax 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, expectations and treatment with respect to retirement plans;

- availability, adequacy, and shift in mix, of gas supplies;
- effects of new or anticipated changes in critical accounting policies or estimates;
- approval and adequacy of regulatory deferrals;
- effects and efficacy of regulatory mechanisms; and
- environmental, regulatory, litigation and insurance costs 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 performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed at Item 1A., "Risk Factors" of Part I and 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", respectively, of Part II of this report.

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

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NORTHWEST NATURAL GAS COMPANY
PART I

ITEM 1. BUSINESS

OVERVIEW

Northwest Natural Gas Company (NW Natural or the Company) was incorporated under the laws of Oregon in 1910. Our Company and its predecessors have supplied gas service to the public since 1859, and we have been doing business as NW Natural since 1997. We maintain operations in Oregon, Washington, and California and conduct business through NW Natural and its subsidiaries. References in this discussion to "Notes" are to the Notes to the Consolidated Financial Statements in Item 8 of this report.

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 storage facilities located in Oregon and California. In addition, we have investments and other non-utility activities we aggregate and report as other. See Note 4 to the Consolidated Financial Statements for further information on total assets and results of operations for our segments for the years ended December 31, 2016, 2015 and 2014.

The utility business is our largest segment, while our gas storage businesses account for the majority of our remaining net income. The following table reflects the percentage allocation between segments and other as of December 31, 2016:

		Non-Utility[1]		
	Utility	Gas Storage[2]	Other	Total
Assets	91.1%	8.3 %	0.6 %	100.0%
Net Income	92.7%	7.3 %	— %	100.0%

(1) We refer to our gas storage segment and other as non-utility as they are not included in our regulated gas distribution business; however, certain aspects of the gas storage segment and other may be regulated by the OPUC, WUTC, CPUC, or FERC.

(2) Our gas storage segment includes asset management services for both the utility and non-utility portion of our Mist gas storage facility.

LOCAL GAS DISTRIBUTION "UTILITY"

The utility is principally engaged in the regulated distribution of natural gas in Oregon and southwest Washington to over 725,000 customers with approximately 89% of our customers located in Oregon and 11% located in Washington. In total, we provide natural gas service to over 100 cities in 18 counties with an estimated population of 3.5 million in our service territory.

We have been allocated an exclusive service territory by the OPUC and WUTC, which includes a major portion of western Oregon, including the Portland metropolitan area, most of the Willamette Valley, the Coastal area from

Astoria to Coos Bay, and portions of Washington along the Columbia River. Portland serves as one of the largest international ports on the West Coast and is a key distribution center due to its comprehensive transportation system of ocean and river shipping, transcontinental railways and highways, and an international airport. Major businesses located in our service territory include retail, manufacturing, and high-technology industries.

NW Natural is deeply committed to environmental stewardship and leveraging the benefits of natural gas to support clean energy policies in the communities we serve. We are proud of distributing natural gas in an environmentally responsible manner to our customers and leading our industry on several fronts. From reducing carbon emissions in our distribution system by modernizing and removing cast iron and bare steel pipe to pioneering greater customer alignment on energy conservation through a decoupling mechanism that breaks the link between utility earnings and the quantity of natural gas sold - we have collaborated with regulators to drive environmentally responsible policies. In addition, we help our customers reduce or offset their natural gas usage through energy efficiency programs and our support of carbon-reduction biogas projects at dairies and farms.

As Oregon transitions to a clean energy future with the elimination of coal-fired electric generation and new renewable energy standards, we believe natural gas will be critical to achieving this future. Natural gas is necessary to reliably integrate renewables, as it allows electric generation to adjust quickly when energy sources such as wind and solar fluctuate with natural variability. One example is our North Mist gas storage expansion project, which will provide no-notice gas storage services to an electric generation facility, allowing the facility to quickly draw on the storage and integrate more wind power into the electric grid. The North Mist expansion project will be considered as part of the utility since revenues will be earned under a cost of service tariff schedule with the OPUC. In addition, we plan to continue leveraging our modern system and existing infrastructure, help our customers continue reducing and offsetting their consumption, and work in our communities to replace more carbon intensive fuels.

Customers

We serve residential, commercial and industrial customers with no individual customer or industry accounting for more than 10% of our utility revenues. On an annual basis, residential and commercial customers typically account for 55% to 60% of our utility's total volumes delivered and 90% of our utility's margin. Industrial customers largely account for the remaining volumes and utility margin. The following table presents summary customer information as of December 31, 2016:

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	Number of Customers	% of Volumes		% of Utility Margin (1)	
Residential	656,855	35	%	63	%
Commercial	67,278	21	%	27	%
Industrial	1,013	44	%	8	%
Other(1)	N/A	N/A		2	%
Total	725,146	100	%	100	%

(1) Utility margin is also affected by other items, including miscellaneous services, gains or losses from our gas cost incentive sharing mechanism, and other service fees.

Generally, residential and commercial customers purchase both their natural gas commodity (gas sales) and natural gas delivery services (transportation services) from the utility. Industrial customers also purchase transportation services from the utility, but may buy the gas commodity either from the utility or 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 levels, 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, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

Customer growth rates for natural gas utilities in the Pacific Northwest historically have been among the highest in the nation due to lower market saturation as natural gas became widely available as a residential heating source after other fuel options. We estimate natural gas is currently in approximately 60% of residential single-family dwellings in our service territory. Customer growth in our region comes from the following main sources: single-family housing, both new construction and conversions; multifamily housing new construction; and commercial buildings, both new construction and conversions. Single family new construction has consistently been our strongest performing source of growth. Over the last five years, our customer growth has recovered with the economy. Continued customer growth is closely tied to the comparative price of natural gas to electricity and fuel oil and the health of the Portland, Oregon and Vancouver, Washington economies. We believe there is potential for continued growth as natural gas is affordable, reliable, a clean fuel choice, and a preferred energy source in our service territory. See Note 4 for information on the utility's assets and results of operations.

Competitive Conditions

In our service areas, we have no direct competition from other natural gas distributors, but we compete with other forms of energy supply in each customer class. This competition among energy suppliers is based on price, efficiency, reliability, performance, preference, market conditions, technology, federal and state energy policy, and environmental impacts.

For residential and small to mid-size commercial customers, we compete primarily with providers of electricity, fuel oil, and propane.

In the industrial and large commercial markets, we compete with all forms of energy, including competition from wholesale natural gas marketers. In addition, large industrial customers could bypass our local gas distribution system by installing their own direct pipeline connection to the interstate pipeline system. We have designed custom transportation service agreements with several of our largest industrial customers to provide transportation service rates that are competitive with the customer's costs of installing their own pipeline; these agreements generally prohibit bypass. Due to the cost pressures confronting a number of our largest customers competing in global markets, bypass continues to be a competitive threat. Although we do not expect a significant number of our large customers to bypass our system in the foreseeable future, we could experience deterioration of utility margin if customers bypass or switch over to custom contracts with lower profit margins.

Seasonality of Business

Our utility business is seasonal in nature due to higher gas usage by residential and commercial customers during the cold winter heating months. Our other categories of customers experience seasonality in their usage, but to a lesser extent.

Regulation and Rates

The utility is subject to regulation by the OPUC, WUTC, and FERC. These regulatory agencies authorize rates and allow recovery mechanisms to provide our utility the opportunity to recover prudently incurred capital and operating costs from customers, while also earning a reasonable return on investment for investors. In addition, the OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility.

We file general rate cases and rate tariff requests periodically with the commissions to establish approved rates, an authorized ROE, an overall rate of return on rate base (ROR), an authorized utility capital structure, and other revenue/cost deferral and recovery mechanisms.

In addition, under our Mist interstate storage certificate with FERC, the utility is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service. We filed a rate petition for our current rates in 2013 and received approval in 2014 for new maximum cost based rates effective January 1, 2014.

The utility's most recent general rate case in Oregon was effective November 1, 2012, and the latest Washington rate case was effective January 1, 2009. During 2016, our approved rates and recovery mechanisms for each service area included:

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	Oregon	Washington
Authorized Rate Structure:		
ROE	9.5%	10.1%
ROR	7.8%	8.4%
Debt/Equity Ratio	50%/50%	49%/51%
Key Regulatory Mechanisms:		
PGA	X	X
Gas Cost Incentive Sharing	X	
Interstate Storage Sharing	X	X
WARM	X	
Decoupling	X	
SIP(1)	X	
Pension Balancing	X	
Environmental Cost Deferral	X	X
SRRM	X	

(1) Regulatory authority for SIP expired October 31, 2014, however, the bare steel replacement portion of the mechanism remained in place until the end of 2015 and was included in rates for the 2015-2016 PGA.

For a complete discussion of regulatory matters, open dockets, current regulatory activities, and additional details on each rate mechanism, see Part II, Item 7, "Results of Operations—Regulatory Matters" and "Gas Storage".

Gas Supply

The utility strives to secure sufficient, reliable supplies of natural gas to meet the needs of customers at the lowest reasonable cost, while maintaining price stability and managing gas purchase costs prudently. This is accomplished through a comprehensive strategy focused on the following items:

- Diverse Supply - providing diversity of supply sources;
- Diverse Contracts - maintaining a variety of contract durations, types, and counterparties;
- Reliability - ensuring gas resource portfolios are sufficient to satisfy customer requirements under extreme cold weather conditions; and
- Cost Management and Recovery - employing prudent gas cost management strategies.

Diversity of Supply Sources

We purchase our gas supplies primarily from the Alberta and British Columbia areas of Canada and multiple receipt points in the U.S. Rocky Mountains to protect against regional supply disruptions and to take advantage of price differentials. For 2016, 63% of our gas supply came from Canada, with the balance primarily coming from the U.S. Rocky Mountain region. We believe gas supplies available in the western United States and Canada are adequate to serve our core utility requirements for the foreseeable future. We continue to evaluate the long-term supply mix based on projections of gas production and pricing in the U.S. Rocky Mountain region as well as other regions in North America; however, we believe the cost of natural gas coming from western Canada and the U.S. Rocky Mountain region will continue to track with broader U.S. market pricing. Additionally, the extraction of shale gas has increased the availability of gas supplies throughout North America for the foreseeable future.

We supplement our firm gas supply purchases with gas withdrawals from gas storage facilities, including underground reservoirs and LNG storage facilities. Storage facilities are generally injected with natural gas during the off-peak months in the spring and summer and the gas is withdrawn for use during peak demand months in the winter.

The following table presents the storage facilities available for our utility supply:

	Maximum Daily Deliverability (therms in millions)	Designed Storage Capacity (Bcf)
Gas Storage Facilities:		
Owned Facility:		
Mist, Oregon(1)	3.1	10.6
Contracted Facilities:		
Jackson Prairie, Washington(2)	0.5	1.1
Alberta, Canada(3)	0.4	2.5
LNG Facilities:		
Owned Facilities:		
Newport, Oregon	0.6	1.0
Portland, Oregon	1.3	0.6
Total	5.9	15.8

(1) The Mist gas storage facility has a total maximum daily deliverability of 5.4 million therms and a total designed storage capacity of about 16 Bcf, of which 3.1 million therms of daily deliverability and 10.6 Bcf of storage capacity are reserved for core utility customers.

(2) The storage facility is located near Chehalis, Washington and is contracted from Northwest Pipeline, a subsidiary of The Williams Companies.

(3) This resource does not add to our total peak day capacity, but mitigates price risks as it displaces equivalent volumes of heating season spot purchases.

The Mist facility is used for both utility and non-utility purposes. Under our regulatory agreements with the OPUC and WUTC, non-utility gas storage at Mist can be developed in advance of core utility customer needs but is subject to recall by the utility when needed to serve utility customers as their demand increases. In 2016, the utility did not recall additional deliverability or associated storage capacity from the non-utility business to serve core utility customer needs.

In addition, we have the ability to recall pipeline capacity and supply resources from certain customers if needed to meet high demand requirements.

Diverse Contract Durations and Types

We have a diverse portfolio of short-, medium-, and long-term firm gas supply contracts and a variety of contract types including firm and interruptible supplies as well as supplemental supplies from gas storage facilities.

Our portfolio of firm gas supply contracts typically includes the following gas purchase contracts: year-round and winter-only baseload supplies; seasonal supply with an option to call on additional daily supplies during the winter heating season; and daily or monthly spot purchases.

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During 2016, we purchased a total of 668 million therms under contracts with durations outlined in the chart below:

Contract Duration (primary term)	Percent of Purchases	
Long-term (one year or longer)	27	%
Short-term (more than one month, less than one year)	35	
Spot	38	
Total	100	%

We renew or replace gas supply contracts as they expire. During 2016, only one supplier provided over 10% of our gas supply requirements.

Reliability

The effectiveness of our gas distribution system ultimately rests on whether we provide reliable service to our core utility customers. To ensure our effectiveness, we develop a composite design year, including a seven day design peak event based on the most severe cold weather experienced during the last 30 years in our service territory.

Our projected maximum design day firm utility customer sendout totals are approximately 9.8 million therms. Of this total, we are currently capable of meeting about 55% of our maximum design day requirements with gas from storage located within or adjacent to our service territory, while the remaining supply requirements would come from gas purchases under firm gas purchase contracts and recall agreements.

To supplement near-term natural gas supplies, we can segment transportation capacity during the heating seasons, if needed. Pipeline segmentation is a natural gas transportation mechanism under which a shipper can leverage its firm pipeline transportation capacity by separating it into multiple segments with alternate delivery routes. The reliability of service on these alternate routes will vary depending on the constraints of the pipeline system. For those segments with acceptable reliability, segmentation provides a shipper with increased flexibility and potential cost savings compared to traditional pipeline service. During the 2015-2016 and 2016-2017 heating seasons, we segmented approximately 0.6 million therms per day of our firm pipeline transportation capacity that flowed from Stanfield, Oregon to various points south of Molalla, Oregon.

We believe our gas supplies would be sufficient to meet existing firm customer demand if we were to experience maximum design day weather conditions. We will continue to evaluate and update our forecasted requirements and incorporate changes in our Integrated Resource Plan (IRP) process.

The following table shows the sources of supply projected to be used to satisfy the design day sendout for the 2016-2017 winter heating season:

Therms in millions	Therms	Percent	
Sources of utility supply:			
Firm supply purchases	3.4	34	%
Mist underground storage (utility only)	3.1	32	
Company-owned LNG storage	1.9	19	
Off-system storage contract	0.5	5	
Pipeline segmentation capacity	0.6	6	
Recall agreements	0.4	4	
Total	9.9	100	%

The OPUC and WUTC have IRP processes in which utilities define different growth scenarios and corresponding resource acquisition strategies in an effort to evaluate supply and demand resource requirements, consider uncertainties in the planning process and the need for flexibility to respond to changes, and establish a plan for providing reliable service at the least cost.

In general, the IRP is filed biannually with both the OPUC and the WUTC. An update is filed in Oregon in the off year. The OPUC acknowledges the Company's action plan; whereas the WUTC provides notice that our IRP has met the requirements of the Washington Administrative Code. OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. However, the Commissioners generally indicate that they would give considerable weight in prudence reviews to utility actions consistent with acknowledged plans. The WUTC has indicated the IRP process is one factor it will consider in a prudence review. We filed our 2016 IRP in both Oregon and Washington in August 2016. We received a letter of compliance from the WUTC in December 2016 and acknowledgment from the OPUC in February 2017. We plan to file an update to the IRP with the Oregon Commission in 2018.

Gas Cost Management Strategy

The cost of gas sold to utility customers primarily consists of the following items, which are included in annual PGA rates: purchase price paid to suppliers; charges paid to pipeline companies to transport gas to our distribution system; costs paid to store gas; our gas reserves contracts; and gains or losses related to gas commodity derivative contracts.

We employ a number of strategies to mitigate the cost of gas sold to utility customers. Our primary strategies for managing gas commodity price risk include:

- negotiating fixed prices directly with gas suppliers;
- negotiating financial derivative contracts that: (1) effectively convert floating index prices in physical gas supply contracts to fixed prices (referred to as commodity price swaps); or (2) effectively set a ceiling or floor price, or both, on floating index priced physical supply contracts (referred to as commodity price options such as calls, puts, and collars). See Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk—Credit Risk—Credit Exposure to Financial Derivative Counterparties";

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- buying physical gas supplies at a set price and injecting the gas into storage for price stability and to minimize pipeline capacity demand costs; and
- investing in gas reserves for longer term price stability. See Note 11 for additional information about our gas reserves.

We also contract with an independent energy marketing company to capture opportunities regarding our storage and pipeline capacity when those assets are not serving the needs of our core utility customers. Our asset management activities provide cost savings that reduce our utility customer's cost of gas and opportunities to generate incremental revenues for our shareholders from a regulatory incentive-sharing mechanism, which are included in our gas storage segment.

Cost Recovery

Mechanisms for gas cost recovery are designed to be fair and reasonable, with an appropriate balance between the interests of our customers and shareholders. In general, utility rates are designed to recover the costs of, but not to earn a return on, the gas commodity sold. We minimize risks associated with gas cost recovery by resetting customer rates annually through the PGA and aligning customer and shareholder interests through the use of sharing, weather normalization, and conservation mechanisms in Oregon. See Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms" and "Results of Operations—Business Segments—Local Gas Distribution Utility Operations—Cost of Gas."

Transportation of Gas Supplies

Our local gas distribution system is reliant on a single, bi-directional interstate transmission pipeline to bring gas supplies into our distribution system. Although we are dependent on a single pipeline, the pipeline's gas flows into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the U.S. Rocky Mountain supply basins.

We incur monthly demand charges related to our firm pipeline transportation contracts. Our largest pipeline agreements are with Northwest Pipeline. These contracts are multi-year contracts with expirations ranging from 2018 to 2046. We actively work with Northwest Pipeline and others to renew contracts in advance of expiration to ensure gas transportation capacity is sufficient to meet our utility needs.

Rates for interstate pipeline transportation services are established by FERC within the U.S. and by Canadian authorities for services on Canadian pipelines.

As mentioned above, our service territory is dependent on a single pipeline for its natural gas supply. Although supply has not been disrupted in the recent past, pipeline replacement projects and long-term projected natural gas demand in our region underscore the need for pipeline transportation diversity. In addition, there are potential industrial projects in the region, which could increase the demand for natural gas and the need for additional pipeline capacity and pipeline diversity.

Currently, there are various interstate pipeline projects proposed, including the Trail West Pipeline in which the Company has an interest, that could meet the forecasted demand for the region and our Company. However, the location of any future pipeline project will likely depend on the location of committed industrial projects. We will continue to evaluate and closely monitor the currently prospected projects to determine the best option for ratepayers. The Company also has an equity investment in Trail West Holdings, LLC (TWH) that is developing plans to build the Trail West pipeline. This pipeline would connect TransCanada Pipelines Limited's (TransCanada) Gas Transmission

Northwest (GTN) interstate transmission line to our local gas distribution system. If constructed, this pipeline would provide another transportation path for gas purchases from Alberta and the U.S. Rocky Mountains in addition to the one that currently moves gas through the Northwest Pipeline system.

Gas Distribution

The primary goals of our gas distribution operations are safety and reliability of our system, which entails building and maintaining a safe pipeline distribution system.

Safety and the protection of our employees, our customers, and the public at large are, and will remain, our top priorities. We construct, operate and maintain our pipeline distribution system and storage operations with the goal of ensuring natural gas is delivered and stored safely, reliably, and efficiently.

NW Natural has one of the most modern distribution systems in the country with no identified cast iron pipe or bare steel main. We removed the final three miles of known bare steel from our system in 2015 and completed our cast iron pipe removal in 2000. Since the 1980s, we have taken a proactive approach to replacement programs and partnered with our Commissions on progressive regulation to further safety and reliability efforts for our distribution system. In the past, we had a cost recovery program in Oregon that encompassed the Company’s programs for bare steel replacement, transmission pipeline integrity management, and distribution pipeline integrity management. During 2016, we worked with the OPUC and other Oregon natural gas utilities to establish guidelines for future safety cost-recovery tracking programs. In October 2016, an all-party agreement for the docket was filed with the OPUC and is currently undergoing review. See Part II, Item 7, "Results of Operations—Regulatory Matters—System Integrity Program".

Natural gas distribution businesses are likely to be subject to even greater federal and state regulation in the future due to pipeline incidents involving other companies. Additional regulations from the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) are currently under development. During 2016 PHMSA issued final regulations regarding enhanced emergency order procedures, which became effective upon issuance. In addition, PHMSA issued final rules addressing underground storage and excess flow valves, with effective dates in 2017. We anticipate final regulations for the remaining rules to be issued in 2017, with effective dates in 2017 to 2018. Accordingly, we will continue to work diligently with industry associations as well as federal and state

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regulators to ensure the safety of our system and compliance with new laws and regulations. We expect the costs to our utility associated with compliance of federal, state, and local rules would be recoverable in rates.

North Mist Gas Storage Expansion Project

In Oregon, there is a need to integrate intermittent resources, such as wind and solar, into the power system with policymakers committing to the elimination of coal-fired electric generation and moving toward a 50% renewable electricity standard by 2040. New, flexible natural gas-fired electric generation facilities and associated gas storage are necessary to support the integration of renewable resources. To that end, we are expanding our gas storage facility near Mist, Oregon to provide innovative no-notice gas storage service. This expansion project will be dedicated solely to Portland General Electric (PGE) to support their gas-fired electric power generation facilities under an initial 30 year contract with options to extend, totaling up to an additional 50 years upon mutual agreement of the parties.

The expansion project includes a new reservoir providing up to 2.5 Bcf of available storage, an additional compressor station with design capacity of 120,000 decatherms of gas per day, no-notice service that can be drawn on rapidly, and a 13-mile pipeline to connect to PGE's gas plants at Port Westward. The current estimated cost of the expansion is approximately $128 million with a targeted in-service date of the winter of 2018-19, depending on completion of all construction and commissioning activities.

We expect upon completion, revenues will be derived from a long term cost of service contract for storage services and are expected to be recognized on a straight-line basis. These revenues will be earned immediately under an established cost of service tariff schedule with the OPUC based on the utility's current, authorized rate structure as determined in its latest rate case. Billing rates will be updated annually to the current depreciable asset level and forecasted operating expenses.

GAS STORAGE

Our gas storage segment includes the following:

- the non-utility portion of the Mist gas storage facility near Mist, Oregon;
- our Gill Ranch gas storage facility near Fresno, California; and
- asset management services provided by an independent energy marketing company.

In general, the supply of natural gas remains relatively stable over the course of a year, while the demand for natural gas typically fluctuates seasonally. Storage facilities allow customers to purchase and inject natural gas supplies during periods of low demand and withdraw these supplies for use or resale during periods of higher demand. These facilities allow us to capitalize on the imbalance of supply and demand and price volatility for natural gas.

See Note 4 for more information on gas storage assets and results of operations and Part II, Item 7, "Financial Condition—Capital Structure—Liquidity and Capital Resources".

Gas Storage Facilities

The following table provides information concerning the Company's non-utility gas storage facilities:

	Designed Storage	Maximum Deliverability (Therms in	Injection (Therms in millions/day)(3)

	Capacity (Bcf)	millions/day[3]	
Mist Storage[1]	5.4	2.3	0.8
Gill Ranch Storage[2]	15.0	4.9	2.4

(1) Approximately 5.4 Bcf of a total designed storage capacity of about 16 Bcf at Mist is currently available to our gas storage segment. The remaining 10.6 Bcf is used to provide gas storage for our local distribution business and its utility customers. In addition to designed storage capacity above, capacity may incrementally increase based on variations in the heat content of the stored gas. All storage capacity and daily deliverability currently developed for the gas storage segment at Mist is available for recall by the utility. In May 2015, the utility recalled approximately 0.3 million therms per day of deliverability and 0.7 Bcf of capacity for core utility customer use. There were no recalls by the utility in 2016.

(2) Our share of the Gill Ranch facility is currently 15 Bcf out of a total capacity of 20 Bcf.

(3) Our share of the designed daily maximum injection and deliverability rates.

Mist Storage Facility

The Mist storage facility began operations in 1989 and currently consists of seven depleted natural gas reservoirs, 22 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines and other related facilities.

SERVICES. Mist provides multi-cycle gas storage services to customers in the interstate and intrastate markets from the facility located in Columbia County, Oregon, near the town of Mist. The Mist field was initially converted to storage operations for our utility customers. Since 2001, gas storage capacity at Mist has also been made available to interstate customers by developing new incremental capacity in advance of core utility customer requirements to meet the demands for interstate storage service. These interstate storage services are offered under a limited jurisdiction blanket certificate issued by FERC. In addition, since 2005 we have offered intrastate firm storage services in Oregon under an OPUC-approved rate schedule as an optional service to eligible non-residential utility customers.

CUSTOMERS. For Mist storage services, firm service agreements with customers are entered into with terms typically ranging from 1 to 10 years. Currently, our gas storage revenues from Mist are derived primarily from firm service customers who provide energy related services, including natural gas distribution, electric generation, and energy marketing. Three storage customers currently account for all of our existing contracted non-utility gas storage capacity at Mist, with the largest customer accounting for about half of the total capacity. These three customers have contracts expiring at various dates through 2020.

COMPETITIVE CONDITIONS. Our Mist gas storage facility benefits from limited competition from other Pacific Northwest storage facilities primarily because of its geographic location. However, competition from other storage providers in Washington and Canada, as well as competition for interstate pipeline capacity, does exist. In the future, we could face increased competition from new or expanded gas storage facilities as well as from new natural gas pipelines, marketers, and alternative energy sources.

SEASONALITY. Mist gas storage revenues generally do not follow seasonal patterns similar to those experienced by the utility because most of the storage capacity is contracted with customers for firm service, which are primarily in the form of fixed monthly reservation charges and are not affected by customer usage. However, there is seasonal variation with Mist storage capacity and deliverability related to utility customers' lower demand during the spring and summer months. This surplus storage capacity and deliverability and related transportation capacity can be optimized under regulatory sharing agreements with the OPUC and WUTC. See "Asset Management" below.

REGULATION. Our Mist facility is subject to regulation by the OPUC and WUTC. In addition, FERC has approved maximum cost-based rates under our Mist interstate storage certificate. We are required to file either a petition for rate approval or a cost and revenue study with FERC at least every five years to change or justify maintaining the existing rates for the interstate storage service. In December 2013, we filed for a rate petition, which was approved in 2014 with rates being effective January 1, 2014. See Part II, Item 7, "Results of Operations—Regulatory Matters".

EXPANSION OPPORTUNITIES. We are currently expanding our Mist Storage facility to provide 2.5 Bcf of storage to the local electric company. See "North Mist Gas Storage Expansion Project" above. While there are additional expansion opportunities in the Mist storage field, further development is not contemplated at this time and expansion would be based on market demand, project execution, cost effectiveness, available financing, receipt of future permits, and other rights.

Gill Ranch Storage Facility

Gill Ranch Storage, LLC (Gill Ranch), our subsidiary, has a joint project agreement with Pacific Gas and Electric Company (PG&E) to develop and own the Gill Ranch underground natural gas storage facility near Fresno, California. Currently, Gill Ranch is the sole operator of the facility. The facility began operations in 2010 and consists of three depleted natural gas reservoirs, 12 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines, an electric substation, a natural gas transmission pipeline extending 27 miles from the storage field to an interconnection with the PG&E transmission system, and other related facilities. Gill Ranch owns the rights to 75% of the available storage capacity at the facility. Gill Ranch’s share of the facility currently provides 15.0 Bcf of working gas capacity.

California has been impacted by challenging market conditions for gas storage, with contract prices in the region near historic lows and a greater number of competitors in the area compared to the Pacific Northwest region. Prices for the 2016-17 gas year showed slight improvement, however prices remained low relative to the pricing in our original long-term contracts which ended primarily in the 2013-14 gas storage year. In the future, we may see

improved pricing from 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 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. We continue to explore opportunities to increase revenues by identifying higher value customers to provide with enhanced services. We may also look at other strategic alternatives that help capitalize on opportunities that fit our business-risk profile.

SERVICES. Gill Ranch provides intrastate, multi-cycle storage services in California at market-based rates under a CPUC-approved tariff that includes firm storage service, interruptible storage service, and park and loan storage services. Our Gill Ranch facility is not currently authorized to provide interstate gas storage services.

CUSTOMERS. Customer contracts for firm storage capacity at Gill Ranch are as long as 27 years in duration; however, the majority of the contracted capacity is shorter term in nature due to market conditions. In the near-term, we expect Gill Ranch to contract for terms ranging from one to five years. For the 2016-17 gas storage year, Gill Ranch has several storage customers, with the largest single contract accounting for approximately 13% of our storage capacity. In the near term, we continue to expect shorter contract lengths reflecting current market prices and trends.

The California market served by Gill Ranch is larger, and has a greater diversity of prospective customers, than the Pacific Northwest market served by Mist. Therefore, we expect less sensitivity to any single customer or group of customers at Gill Ranch. Current Gill Ranch customers provide energy related services, including natural gas production, marketing, and electric generation.

COMPETITIVE CONDITIONS. The Gill Ranch storage facility currently competes with a number of other storage providers, including local integrated gas companies and other independent storage providers (ISPs) in the northern California market. There are currently four ISPs authorized by the CPUC to provide storage services in California, with the Gill Ranch storage facility comprising approximately 12% of the storage capacity held by ISPs. An acquisition during 2016 consolidated approximately 80% of the storage capacity authorized by the CPUC to ISPs in California. Although this consolidation has not had an immediate impact on our storage business, the ultimate effect of this dominant market share on pricing and contracting levels for our Gill Ranch storage facility remains unknown and cannot be predicted at this time.

In addition, in October 2015 a significant natural gas leak occurred at an unaffiliated southern California gas storage facility that persisted through early 2016. At this time, we do not know the long-term effects of this incident on gas storage prices. The southern California market is largely independent from the northern California gas storage

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market due to transportation barriers. However, in response to this incident, new legislation was enacted in California in September 2016, which directed the California Department of Oil, Gas and Geothermal Resources (DOGGR) to develop new regulations for gas storage wells. In addition to the DOGGR legislation, similar efforts are underway at the federal level under the PHMSA, as discussed above in "Local Gas Distribution—Utility." While the regulations are still under development, and their ultimate impact is unknown, it is likely the PHMSA and pending DOGGR regulations will result in higher costs for all storage providers. As a result of the legislation and pending regulation, the nature of, and demand for, future storage contracts, costs of operating, and 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 $196.9 million at December 31, 2016. We continue to assess these conditions along with other strategic alternatives and their impact on the value of the asset on an ongoing basis. See Note 2 of the Notes to Consolidated Financial Statements for more information regarding our accounting policy for impairment of long-lived assets.

SEASONALITY. While the majority of our Gill Ranch revenues are not subject to seasonality, and although we expect much of the storage revenue at Gill Ranch to be in the form of fixed monthly demand charges, cash flows can fluctuate due to timing of asset management and other revenues. In addition, a significant portion of operating costs at Gill Ranch are subject to fluctuations based on periods when storage customers elect to inject or withdraw.

REGULATION. Gill Ranch has a tariff on file with the CPUC authorizing it to charge market-based rates for the storage services offered. See Part II, Item 7, "Results of Operations–Regulatory Matters".

EXPANSION OPPORTUNITIES. Subject to market demand, project execution, available financing, receipt of future permits, and other rights, the Gill Ranch storage facility can be expanded beyond the current combined permitted capacity of 20 Bcf without further expansion of the takeaway pipeline system. Taking these considerations into account and with certain infrastructure modifications, we currently estimate the Gill Ranch storage facility could support an additional 25 Bcf of storage capacity, bringing the total storage capacity to approximately 45 Bcf, of which our current rights would give us up to an additional 7.5 Bcf or ownership of a total of approximately 22.5 Bcf.

Asset Management

We contract with an independent energy marketing company to provide asset management services, primarily through the use of commodity exchange agreements and

pipeline capacity release transactions. The results are included in the gas storage segment, except for amounts allocated to our utility pursuant to regulatory sharing agreements involving the use of utility assets. Utility pre-tax income from third-party asset management services is subject to revenue sharing with core utility customers. See Part II, Item 7, "Results of Operations—Business Segments—Gas Storage".

OTHER

We have non-utility investments and other business activities which are aggregated and reported as other. Other primarily consists of:

- an equity method investment in a joint venture to build and operate a gas transmission pipeline in Oregon. TWH is owned 50% by NWN Energy, a wholly-owned subsidiary of NW Natural, and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation;
- a minority interest in Kelso-Beaver Pipeline held by our wholly-owned subsidiary NNG Financial Corporation (NNG Financial); and
- other operating and non-operating income and expenses of the parent company that are not included in utility or gas storage operations.

The pipelines referred to above are regulated by FERC. Less than 1% of our consolidated assets and consolidated net income are related to activities in other. See Note 4 for summary information for these assets and results of operations.

ENVIRONMENTAL MATTERS

Properties and Facilities

We own, or previously owned, properties and facilities that are currently being investigated that may require environmental remediation and are subject to federal, state and local laws and regulations related to environmental matters. These laws and regulations may require expenditures over a long timeframe to address certain environmental impacts. Estimates of liabilities for environmental costs are difficult to determine with precision because of the various factors that can affect their ultimate disposition. These factors include, but are not limited to, the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete, or experience with existing technology that proves ineffective;
- the ultimate selection of a particular technology;
- the level of remediation required;
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site; and
- the application of environmental laws that impose joint and several liabilities on all potentially responsible parties.

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We have received recovery of a portion of such environmental costs through received insurance proceeds and seek the remainder of such costs through customer rates, and we believe recovery of these costs is probable. In Oregon, we have a mechanism to recover expenses, subject to an earnings test and allocation rules. See Part II, Item 7, "Results of Operations—Rate Matters—Rate Mechanisms—Environmental Costs", Note 2 and Note 15.

Greenhouse Gas Matters

We recognize our businesses are likely to be impacted by future requirements to address greenhouse gas emissions. Future federal and/or state requirements may seek to limit emissions of greenhouse gases, including both carbon dioxide (CO_2) and methane. These potential laws and regulations may require certain activities to reduce emissions and/or increase the price paid for energy based on its carbon content.

Current federal rules require the reporting of greenhouse gas emissions. In September 2009, the EPA issued a final rule requiring the annual reporting of greenhouse gas emissions from certain industries, specified large greenhouse gas emission sources, and facilities that emit 25,000 metric tons or more of CO_2 equivalents per year. We began reporting emission information in 2011. Under this reporting rule, local gas distribution companies like NW Natural are required to report system throughput to the EPA on an annual basis. The EPA also issued additional greenhouse gas reporting regulations requiring the annual reporting of fugitive emissions from our operations.

Similarly, the Clean Air Rule (CAR) was enacted by the state of Washington's Department of Ecology on September 15, 2016. The Washington rule caps the maximum greenhouse gas emissions allowed from stationary sources such as large manufacturers, as well as petroleum producers and natural gas utilities. For gas distribution utilities, the usage by their customers of natural gas is considered to produce emissions that are attributed to the utility. Entities exceeding the applicable limit must reduce their emissions, develop projects that would reduce emissions or purchase emission reduction units (ERUs) or renewable energy credits (RECs) or, to a limited extent, acquire allowances from out-of-state multi-sector greenhouse gases (GHG) programs. We anticipate that compliance by gas distribution utilities, such as NW Natural, would primarily be achieved through the purchase of ERUs, although there is significant uncertainty regarding ERU availability and price at this time. We filed legal action jointly with Avista Corporation, Cascade Natural Gas Corp. and Puget Sound Energy in late September 2016 to challenge the Washington rule based on flaws in its design. However, as CAR became effective January 1, 2017, we have commenced compliance efforts and also plan to pursue regulatory recovery of such costs. While there is still uncertainty regarding potential compliance costs, we expect to be able to recover these costs in rates, and as such do not expect this rule to materially affect our consolidated financial position and results of operations.

The outcome of these or any additional federal and state policy developments in the area of climate change cannot be determined at this time, but these initiatives could produce a number of results including new regulations, legal actions, additional charges to fund energy efficiency activities, or other regulatory actions. The adoption and implementation of any regulations limiting emissions of greenhouse gas from our operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, which could result in an increase in the prices we charge our customers or a decline in the demand for natural gas. On the other hand, because natural gas is a low-carbon fuel, it is also possible future carbon constraints could create additional demand for natural gas for electric generation, direct use of natural gas in homes and businesses, and as a reliable and relatively low-emission back-up fuel source for alternative energy sources. Requirements to reduce greenhouse gas emissions from the transportation sector, such as those in Oregon’s clean fuel standard, could also result in additional demand for natural gas fueled vehicles.

We continue to take proactive steps to collaboratively address future greenhouse gas emission matters, including actively participating in policy development in Oregon and, at the federal level, within the American Gas Association. We engage in policy development and in identifying ways to reduce greenhouse gas emissions in our own operations. We also help our customers reduce and offset their gas use, through partnership with the Energy Trust of Oregon offering efficiency programs and the Smart Energy program, which allows customers to voluntarily contribute funds to projects such as biodigesters on dairy farms that offset the greenhouse gases produced from their natural gas use.

EMPLOYEES

At December 31, 2016, the utility workforce consisted of 611 members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO, and 497 non-union employees. Our labor agreement with members of OPEIU covers wages, benefits and working conditions. On May 22, 2014, our union employees ratified a new labor agreement (Joint Accord) that extends to November 30, 2019, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement.

At December 31, 2016, our non-utility subsidiaries had a combined workforce of 15 non-union employees, of which the majority of our employees at the Gill Ranch facility voted to unionize as part of IBEW Local Union No. 1245. We are currently in the process of bargaining the first contract for 8 of these employees and the ultimate outcome of such negotiations is unknown at this time. Our subsidiaries receive certain services from centralized operations at the utility, and the utility is reimbursed for those services pursuant to a Shared Services Agreement.

ADDITIONS TO INFRASTRUCTURE

We make capital expenditures in order to maintain and enhance the safety and integrity of our pipelines, gate stations, storage facilities and related assets, to expand the reach or capacity of those assets, or improve the efficiency of our operations. We expect to make a significant level of capital expenditures for additions to utility and gas storage infrastructure over the next five years, reflecting continued investments in customer growth, distribution system

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improvements, technology, and an expansion at our North Mist gas storage facility. For the five-year period ending in 2021, capital expenditures for the utility are estimated to be between $850 and $950 million, which excludes any potential future gas reserves investments.

Included in the five year period, 2017 utility capital expenditures are estimated to be between $225 and $250 million, including $80 to $90 million for our North Mist gas storage facility expansion, and non-utility capital investments of less than $5 million. Additional spend for gas storage and other investments during and after 2017 will depend largely on additional gas storage legislation and expansion opportunities. See additional discussion in Part II, Item 7 "Financial Condition—Cash Flows—Investing Activities".

EXECUTIVE OFFICERS OF THE REGISTRANT

For information concerning our executive officers, see Part III, Item 10.

AVAILABLE INFORMATION

We file annual, quarterly and current reports and other information with the Securities and Exchange Commission (SEC). Reports, proxy statements and other information filed by us can be read, copied and requested through the SEC by mail at U.S. Securities and Exchange Commission, 100 F Street, N.E., Washington, D.C. 20549, or online at its website (http://www.sec.gov). You can obtain information about access to the Public Reference Room and how to access or request records by calling the SEC at 1-800-SEC-0330. The SEC website contains reports, proxy and information statements and other information we file electronically. In addition, we make available on our website (http://www.nwnatural.com), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) and proxy materials filed under Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

We have adopted a Code of Ethics for all employees and officers that is available on our website. We intend to disclose amendments to, and any waivers from the Code of Ethics on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about the Company are also available at the website. Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, NW Natural, One Pacific Square, 220 N.W. Second Avenue, Portland, Oregon 97209, telephone 503-226-4211 ext. 2402.

ITEM 1A. RISK FACTORS

Our business and financial results are subject to a number of risks and uncertainties, many of which are not within our control, which could adversely affect our business, financial condition, and results of operations. Additional risks and uncertainties that are not currently known to the Company or that are not currently believed by the Company to be material may also harm the Company's business, financial condition, and results of operations. When considering any investment in our securities, investors should carefully consider the following information, as well as information contained in the caption "Forward-Looking Statements", Item 7A, and other documents we file with the SEC. This list is not exhaustive and the order of presentation does not reflect management's determination of priority or likelihood. Additionally, our listing of risk factors that primarily affects one of our business segments does not mean that such risk factor is inapplicable to our other business segments.

Risks Related to our Business Generally

REGULATORY RISK. Regulation of our businesses, including changes in the regulatory environment, failure of regulatory authorities to approve rates which provide for timely recovery of our costs and an adequate return on invested capital, or an unfavorable outcome in regulatory proceedings may adversely impact our financial condition and results of operations.

The OPUC and WUTC have general regulatory authority over our utility business in Oregon and Washington, respectively, including the rates charged to customers, authorized rates of return on rate base, including ROE, the amounts and types of securities we may issue, services we provide and the manner in which we provide them, the nature of investments we make, actions investors may take with respect to our company, and deferral and recovery of various expenses, including, but not limited to, pipeline replacement, environmental remediation costs, commodity hedging expense, transactions with affiliated interests, weather adjustment mechanisms and other matters. Similarly, in our gas storage businesses FERC has regulatory authority over interstate storage services, the CPUC has regulatory authority over our Gill Ranch storage operations, and the WUTC and OPUC have regulatory authority over our Mist storage operations.

The prices the OPUC and WUTC allow us to charge for retail service, and the maximum FERC-approved rates FERC authorizes us to charge for interstate storage and related transportation services, are the most significant factors affecting our financial position, results of operations and liquidity. The OPUC and WUTC have the authority to disallow recovery of costs they find imprudently incurred or otherwise disallowed. Additionally, the rates allowed by the FERC may be insufficient for recovery of costs incurred. We expect to continue to make expenditures to expand, improve and operate our utility distribution and gas storage systems. Regulators can find such expansions or improvements of expenditures were not prudently incurred, and deny recovery. Additionally, while the OPUC and WUTC have established an authorized rate of return for our utility through the ratemaking process, the regulatory process does not provide assurance that we will be able to achieve the earnings level authorized.

Moreover, in the normal course of business we may place assets in service or incur higher than expected levels of operating expense before rate cases can be filed to recover those costs—this is commonly referred to as regulatory lag. The failure of any regulatory commission to approve requested rate increases on a timely basis to recover increased costs or to allow an adequate return could adversely impact our financial condition and results of operations.

As a regulated utility, we frequently have dockets open with our regulators. The regulatory proceedings for these dockets typically involve multiple parties, including governmental agencies, consumer advocacy groups, and other third parties. Each party has differing concerns, but all generally have the common objective of limiting amounts included in rates. We cannot predict the timing or outcome of these deferred proceedings or the effects of those outcomes on our results of operations and financial condition.

ENVIRONMENTAL LIABILITY RISK. Certain of our properties and facilities may pose environmental risks requiring remediation, the costs of which are difficult to estimate and which could adversely affect our financial condition, results of operations, and cash flows.

We own, or previously owned, properties that require environmental remediation or other action. We accrue all material loss contingencies relating to these properties. A regulatory asset at the utility has been recorded for estimated costs pursuant to a Deferral Order from the OPUC and WUTC. In addition to maintaining regulatory deferrals, we settled with most of our historical liability insurers for only a portion of the costs we have incurred to date and expect to incur in the future. To the extent amounts we recovered from insurance are inadequate or we are unable to recover these deferred costs in utility customer rates, we would be required to reduce our regulatory assets which would result in a charge to current year earnings. In addition, in our most recent Oregon general rate case, the OPUC approved the SRRM, which limits recovery of our deferred amounts to those amounts which satisfy an annual prudence review and a recently adopted earnings test that requires the Company to contribute additional amounts toward environmental remediation costs above approximately $10 million in years in which the Company earns above its authorized Return on Equity (ROE). To the extent the Company earns more than its authorized ROE in a year, the Company would be required to cover environmental expenses greater than the $10 million with those earnings that exceed its authorized ROE. In addition, the OPUC ordered a review of the SRRM in 2018 or when we obtain greater certainty of environmental costs, whichever occurs first. These ongoing prudence reviews, the earnings test, or the three-year review could reduce the amounts we are allowed to recover, and could adversely affect our financial condition, results of operations and cash flows.

Moreover, we may have disputes with regulators and other parties as to the severity of particular environmental matters, what remediation efforts are appropriate, and the portion of the costs we should bear. We cannot predict with certainty the amount or timing of future expenditures related

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to environmental investigation, remediation or other action, the portions of these costs allocable to us, or disputes or litigation arising in relation thereto. Our liability estimates are based on current remediation technology, industry experience gained at similar sites, an assessment of our probable level of responsibility, and the financial condition of other potentially responsible parties. However, it is difficult to estimate such costs due to uncertainties surrounding the course of environmental remediation, the preliminary nature of certain of our site investigations, and the application of environmental laws that impose joint and several liabilities on all potentially responsible parties. These uncertainties and disputes arising therefrom could lead to further adversarial administrative proceedings or litigation, with associated costs and uncertain outcomes, all of which could adversely affect our financial condition, results of operations and cash flows.

ENVIRONMENTAL REGULATION COMPLIANCE RISK. We are subject to environmental regulations for our ongoing operations, compliance with which could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, groundwater quality and availability, plant and wildlife protection, and other aspects of environmental regulation. For example, we are subject to reporting requirements to the Environmental Protection Agency and the Oregon Department of Environmental Quality regarding greenhouse gas emissions. Similarly, we are also subject to the Washington Department of Ecology Clean Air rule, which caps the maximum GHGs an entity may emit without reduction efforts or offset credit purchases. These and other current and future additional environmental regulations could result in increased compliance costs or additional operating restrictions, which may or may not be recoverable in customer rates. If these costs are not recoverable, they could have an adverse effect on our financial condition and results of operations, particularly if those costs are not fully recoverable from insurance or through utility customer rates.

GLOBAL CLIMATE CHANGE RISK. Future legislation to address global climate change may expose us to regulatory and financial risk. Additionally, our business may be subject to physical risks associated with climate change, all of which could adversely affect our financial condition, results of operations and cash flows.

There are a number of international, federal and state legislative and regulatory initiatives being proposed and adopted in an attempt to measure, control or limit the effects of global warming and overall climate change, including greenhouse gas emissions such as carbon dioxide and methane. Such current or future legislation or regulation could impose on us operational requirements, additional charges to fund energy efficiency initiatives, or levy a tax based on carbon content. Such initiatives could result in us incurring additional costs to comply with the imposed restrictions, provide a cost advantage to energy sources other than natural gas, reduce demand for natural gas,

impose costs or restrictions on end users of natural gas, impact the prices we charge our customers, impose increased costs on us associated with the adoption of new infrastructure and technology to respond to such requirements, and may impact cultural perception of our service or products negatively, diminishing the value of our brand, all of which could adversely affect our business practices, financial condition and results of operations.

Climate change may cause physical risks, including an increase in sea level, intensified storms, water scarcity and changes in weather conditions, such as changes in precipitation, average temperatures and extreme wind or other climate conditions. A significant portion of the nation’s gas infrastructure is located in areas susceptible to storm damage that could be aggravated by wetland and barrier island erosion, which could give rise to gas supply interruptions and price spikes.

These and other physical changes could result in disruptions to natural gas production and transportation systems potentially increasing the cost of gas beyond that assumed in our PGA and affecting our ability to procure gas to meet our customer demand. These changes could also affect our distribution systems resulting in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction. Additionally, to the extent that climate change adversely impacts the economic health or weather conditions of our service territory directly, it could adversely impact customer demand or our customers' ability to pay. Such physical risks could have an adverse effect on our financial condition, results of operations, and cash flows.

STRATEGIC TRANSACTION RISK. Our ability to successfully complete strategic transactions, including merger, acquisition, divestiture, joint venture, business development projects or other strategic transactions is subject to significant risks, including the risk that required regulatory or governmental approvals may not be obtained, risks relating to unknown or undisclosed problems or liabilities, and the risk that for these or other reasons, we may be unable to achieve some or all of the benefits that we anticipate from such transactions.

From time to time, we have pursued and may continue to pursue strategic transactions including merger, acquisition, divestiture, joint venture, business development projects or other strategic transactions. Any such transactions involve substantial risks, including the following:

- acquired businesses or assets may not produce revenues, earnings or cash flow at anticipated levels;
- acquired businesses or assets could have environmental, permitting or other problems for which contractual protections prove inadequate;
- we may assume liabilities which were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;
- we may be unable to obtain the necessary regulatory or governmental approvals to close a transaction, such approvals may be granted subject to terms that are unacceptable to us, or we may be unable to achieve anticipated regulatory

treatment of any such transaction, or such benefits may be delayed or not occur at all.

BUSINESS DEVELOPMENT RISK. Our business development projects may encounter unanticipated obstacles, costs, changes or delays that could result in a project becoming impaired, which could negatively impact our financial condition, results of operations and cash flows.

Business development projects involve many risks. We are currently engaged in several business development projects, including, but not limited to, the early planning and development stages for a regional pipeline in Oregon, and an expansion of our gas storage facility at Mist. We may also engage in other business development projects such as investment in additional long-term gas reserves or CNG refueling stations. These projects may not be successful. Additionally, we may not be able to obtain required governmental permits and approvals to complete our projects in a cost-efficient or timely manner potentially resulting in delays or abandonment of the projects. We could also experience startup and construction delays, construction cost overruns, inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts, changes in customer demand or commitment, public opposition to projects, changes in market prices, and operating cost increases. Additionally, we may be unable to finance our business development projects at acceptable interest rates or within a scheduled time frame necessary for completing the project. One or more of these events could result in the project becoming impaired, and such impairment could have an adverse effect on our financial condition and results of operations.

JOINT PARTNER RISK. Investing in business development projects through partnerships, joint ventures or other business arrangements affects our ability to manage certain risks and could adversely impact our financial condition, results of operations and cash flows.

We use joint ventures and other business arrangements to manage and diversify the risks of certain utility and non-utility development projects, including our Trail West pipeline, Gill Ranch storage and our gas reserves agreements. We may acquire or develop part-ownership interests in other similar projects in the future. Under these arrangements, we may not be able to fully direct the management and policies of the business relationships, and other participants in those relationships may take action contrary to our interests including making operational decisions that could affect our costs and liabilities. In addition, other participants may withdraw from the project, divest important assets, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours.

For example, our gas reserves arrangements, which operate as a hedge backed by physical gas supplies, involve a number of risks. These risks include gas production that is significantly less than the expected volumes, or no gas volumes; operating costs that are higher than expected; changes in our consolidated tax position or tax laws that could affect our ability to take, or timing of, certain tax benefits that impact the financial outcome of this

transaction; inherent risks of gas production, including disruption to operations or complete shut-in of the field; and a participant in one of these business arrangements acting contrary to our interests. In addition, while the cost of the original gas reserves venture is currently included in customer rates, the occurrence of one or more of these risks, could affect our ability to recover this hedge in rates. Further, any new gas reserves arrangements have not been approved for inclusion in rates, and our regulators may ultimately determine to not include all or a portion of future transactions in rates. The realization of any of these situations could adversely impact the project as well as our financial condition, results of operations and cash flows.

OPERATING RISK. Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs, some or all of which may not be fully covered by insurance, and which could adversely affect our financial condition, results of operations and cash flows.

Our operations are subject to all of the risks and hazards inherent in the businesses of local gas distribution and storage, including:

- earthquakes, floods, storms, landslides and other adverse weather conditions and hazards;
- leaks or other losses of natural gas or other chemicals or compounds as a result of the malfunction of equipment or facilities;
- damages from third parties, including construction, farm and utility equipment or other surface users;
- operator errors;
- negative performance by our storage reservoirs that could cause us to fail to meet expected or forecasted operational levels or contractual commitments to our customers;
- problems maintaining, or the malfunction of, pipelines, wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our gas distribution and storage facilities;
- collapse of underground storage caverns;
- operating costs that are substantially higher than expected;
- migration of natural gas through faults in the rock or to some area of the reservoir where existing wells cannot drain the gas effectively resulting in loss of the gas;
- blowouts (uncontrolled escapes of gas from a pipeline or well) or other accidents, fires and explosions; and
- risks and hazards inherent in the drilling operations associated with the development of the gas storage facilities and/or wells.

These risks could result in personal injury or loss of human life, damage to and destruction of property and equipment, pollution or other environmental damage, breaches of our contractual commitments, and may result in curtailment or suspension of our operations, which in turn could lead to significant costs and lost revenues. Further, because our pipeline, storage and distribution facilities are in or near populated areas, including residential areas, commercial business centers, and industrial sites, any loss of human life or adverse financial outcomes resulting from such events could be significant. Additionally, we may not be able to obtain the level or types of insurance we desire, and the insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating risks not covered by insurance could adversely affect our financial condition, results of operations and cash flows.

BUSINESS CONTINUITY RISK. We may be adversely impacted by local or national disasters, pandemic illness, terrorist activities, including cyber-attacks or data breaches, and other extreme events to which we may not be able to promptly respond.

Local or national disasters, pandemic illness, terrorist activities, including cyber-attacks and data breaches, and other extreme events are a threat to our assets and operations. Companies in our industry may face a heightened risk due to exposure to acts of terrorism, including physical and security breaches of our information technology infrastructure in the form of cyber-attacks. These attacks could target or impact our technology or mechanical systems that operate our natural gas distribution, transmission or storage facilities and result in a disruption in our operations, damage to our system and inability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Threatened or actual national disasters or terrorist activities may also disrupt capital markets and our ability to raise capital, or impact our suppliers or our customers directly. Local disaster or pandemic illness could result in part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. A slow or inadequate response to events may have an adverse impact on operations and earnings. We may not be able to obtain sufficient insurance to cover all risks associated with local and national disasters, pandemic illness, terrorist activities and other events. Additionally, large scale natural disasters or terrorist attacks could destabilize the insurance industry making insurance we do have unavailable, which could increase the risk that an event could adversely affect our operations or financial results.

HOLDING COMPANY RISK. If we were to reorganize as a holding company, we would likely depend on our operating subsidiaries to meet financial obligations.

We are pursuing regulatory approval for a reorganization into a holding company structure. If we receive regulatory, Board and shareholder approval and we were to choose to proceed with a holding company structure, Company common stock would be converted or exchanged into shares of a holding company with no significant assets other than the stock of its operating subsidiaries, including NW Natural. Generally, a holding company's ability to pay dividends to shareholders would be dependent on the ability of its subsidiaries to generate sufficient net income and cash flows to service their obligations and pay upstream dividends. The ability of the holding company's subsidiaries to pay upstream dividends and make other distributions would be subject to applicable state law and regulatory restrictions.

EMPLOYEE BENEFIT RISK. The cost of providing pension and postretirement healthcare benefits is subject to changes

in pension assets and liabilities, changing employee demographics and changing actuarial assumptions, which may have an adverse effect on our financial condition, results of operations and cash flows.

Until we closed the pension plans to new hires, which for non-union employees was in 2006 and for union employees was in 2009, we provided pension plans and postretirement healthcare benefits to eligible full-time utility employees and retirees. Most of our current utility employees were hired prior to these dates, and therefore remain eligible for these plans. Our cost of providing such benefits is subject to changes in the market value of our pension assets, changes in employee demographics including longer life expectancies, increases in healthcare costs, current and future legislative changes, and various actuarial calculations and assumptions. The actuarial assumptions used to calculate our future pension and postretirement healthcare expense may differ materially from actual results due to significant market fluctuations and changing withdrawal rates, wage rates, interest rates and other factors. These differences may result in an adverse impact on the amount of pension contributions, pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond rates may have a material adverse effect on the value of our pension fund assets and liabilities. In these circumstances, we may be required to recognize increased contributions and pension expense earlier than we had planned to the extent that the value of pension assets is less than the total anticipated liability under the plans, which could have a negative impact on our financial condition, results of operations and cash flows.

WORKFORCE RISK. Our business is heavily dependent on being able to attract and retain qualified employees and maintain a competitive cost structure with market-based salaries and employee benefits, and workforce disruptions could adversely affect our operations and results.

Our ability to implement our business strategy and serve our customers is dependent upon our continuing ability to attract and retain talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new employees as our largely older workforce retires. We expect that a significant portion of our workforce will retire within the current decade, which will require that we attract, train and retain skilled workers to prevent loss of institutional knowledge or skills gap. Without an appropriately skilled workforce, our ability to provide quality service and meet our regulatory requirements will be challenged and this could negatively impact our earnings. Additionally, within our utility segment, a majority of our workers are represented by the OPEIU Local No.11 AFL-CIO, and are covered by a collective bargaining agreement that extends to November 30, 2019. Within our gas storage segment, approximately 8 employees at our Gill Ranch Storage Facility elected to be represented by IBEW Local Union No. 1245, and are currently in the process of negotiating the first collective bargaining agreement for that employee group. Disputes with unions representing our employees over terms and conditions of their respective agreements could result in instability in our labor relationship and work stoppages that could impact the timely delivery of gas and other services from our utility and gas storage facilities, which could strain relationships with

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customers and state regulators and cause a loss of revenues. Our collective bargaining agreements may also limit our flexibility in dealing with our workforce, and our ability to change work rules and practices and implement other efficiency-related improvements to successfully compete in today’s challenging marketplace, which may negatively affect our financial condition and results of operations.

LEGISLATIVE, COMPLIANCE AND TAXING AUTHORITY RISK. We are subject to governmental regulation, and compliance with local, state and federal requirements, including taxing requirements, and unforeseen changes in or interpretations of such requirements could affect our financial condition and results of operations.

We are subject to regulation by federal, state and local governmental authorities. We are required to comply with a variety of laws and regulations and to obtain authorizations, permits, approvals and certificates from governmental agencies in various aspects of our business. Significant changes in federal, state, or local governmental leadership can accelerate or amplify changes in existing laws or regulations, or the manner in which they are interpreted or enforced. For example, the result of the 2016 United States Presidential election has or will result in leadership change in many federal administrative agencies. Though we cannot predict the changes in laws, regulations, or enforcement that are likely as a result of these transitions, we expect there to be a number of significant changes. We cannot predict with certainty the impact of any future revisions or changes in interpretations of existing regulations or the adoption of new laws and regulations. Additionally, any failure to comply with existing or new laws and regulations could result in fines, penalties or injunctive measures that could affect operating assets. For example, under the Energy Policy Act of 2005, the FERC has civil authority under the Natural Gas Act to impose penalties for current violations of up to $1 million per day for each violation. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance may also increase. Changes in regulations, the imposition of additional regulations, and the failure to comply with laws and regulations could negatively influence our operating environment and results of operations.

Additionally, changes in federal, state or local tax laws and their related regulations, or differing interpretations or enforcement of applicable law by a federal, state or local taxing authority, could result in substantial cost to us and negatively affect our results of operations. Tax law and its related regulations and case law are inherently complex and dynamic. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, upon appeal or through litigation. Our judgments may include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by taxing authorities. Changes in laws, regulations or adverse judgments and the inherent difficulty in quantifying potential tax effects of business decisions may negatively affect our financial condition and results of operations.

SAFETY REGULATION RISK. We may experience increased

federal, state and local regulation of the safety of our systems and operations, which could adversely affect our operating costs and financial results.

The safety and protection of the public, our customers and our employees is and will remain our top priority. We are committed to consistently monitoring and maintaining our distribution system and storage operations to ensure that natural gas is acquired, stored and delivered safely, reliably and efficiently. Given recent high-profile natural gas explosions, leaks and accidents in other parts of the country involving both distribution systems and storage facilities, we anticipate that the natural gas industry may be the subject of even greater federal, state and local regulatory oversight. For example, in 2016, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) was signed into law increasing regulations for natural gas storage pipelines and underground storage facilities.

Similarly, in 2016 California passed legislation directing the Department of Oil, Gas and Geothermal Resources to develop regulations affecting gas storage operations.

We intend to work diligently with industry associations and federal and state regulators to seek to ensure compliance with these and other new laws. We expect there to be increased costs associated with compliance, and those costs could be significant. If these costs are not recoverable in our customer rates, they could have a negative impact on our operating costs and financial results.

HEDGING RISK. Our risk management policies and hedging activities cannot eliminate the risk of commodity price movements and other financial market risks, and our hedging activities may expose us to additional liabilities for which rate recovery may be disallowed, which could result in an adverse impact on our operating revenues, costs, derivative assets and liabilities and operating cash flows.

Our gas purchasing requirements expose us to risks of commodity price movements, while our use of debt and equity financing exposes us to interest rate, liquidity and other financial market risks. In our Utility segment, we attempt to manage these exposures with both financial and physical hedging mechanisms, including our gas reserves transactions which are hedges backed by physical gas supplies. While we have risk management procedures for hedging in place, they may not always work as planned and cannot entirely eliminate the risks associated with hedging. Additionally, our hedging activities may cause us to incur additional expenses to obtain the hedge. We do not hedge our entire interest rate or commodity cost exposure, and the unhedged exposure will vary over time. Gains or losses experienced through hedging activities, including carrying costs, generally flow through the PGA mechanism or are recovered in future general rate cases. However, the hedge transactions we enter into for the utility are subject to a prudence review by the OPUC and WUTC, and, if found imprudent, those expenses may be, and have been previously, disallowed, which could have an adverse effect on our financial condition and results of operations.

In addition, our actual business requirements and available resources may vary from forecasts, which are used as the basis for our hedging decisions, and could cause our exposure to be more or less than we anticipated. Moreover, if our derivative instruments and hedging transactions do not qualify for regulatory deferral and we do not elect hedge accounting treatment under generally accepted accounting standards, our results of operations and financial condition could be adversely affected.

We also have credit-related exposure to derivative counterparties. Counterparties owing us money or physical natural gas commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements to meet our normal business requirements. In that event, our financial results could be adversely affected. Additionally, under most of our hedging arrangements, any downgrade of our senior unsecured long-term debt credit rating could allow our counterparties to require us to post cash, a letter of credit or other form of collateral, which would expose us to additional costs and may trigger significant increases in borrowing from our credit facilities if the credit rating downgrade is below investment grade. Further, based on current interpretations, we are not considered a "swap dealer" or "major swap participant" in 2016, so we are exempt from certain requirements under the Dodd-Frank Act. If we are unable to claim this exemption, we could be subject to higher costs for our derivatives activities.

INABILITY TO ACCESS CAPITAL MARKET RISK. Our inability to access capital, or significant increases in the cost of capital, could adversely affect our financial condition and results of operations.

Our ability to obtain adequate and cost effective short-term and long-term financing depends on maintaining investment grade credit ratings as well as the existence of liquid and stable financial markets. Our businesses rely on access to capital markets, including commercial paper, bond and equity markets, to finance our operations, construction expenditures and other business requirements, and to refund maturing debt that cannot be funded entirely by internal cash flows. Disruptions in capital markets could adversely affect our ability to access short-term and long-term financing. Our access to funds under committed short-term credit facilities, which are currently provided by a number of banks, is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions in the bank or capital financing markets as a result of economic uncertainty, changing or increased regulation of the financial sector, or failure of major financial institutions could adversely affect our access to capital and negatively impact our ability to run our business and make strategic investments.

A negative change in our current credit ratings, particularly below investment grade, could adversely affect our cost of borrowing and access to sources of liquidity and capital. Such a downgrade could further limit our access to borrowing under available credit lines. Additionally, downgrades in our current credit ratings below investment grade could cause additional delays in accessing the capital markets by the utility while we seek supplemental state regulatory approval, which could hamper our ability to access credit markets on a timely basis. A credit downgrade

could also require additional support in the form of letters of credit, cash or other forms of collateral and otherwise adversely affect our financial condition and results of operations.

REPUTATIONAL RISKS. Customers', legislators', and regulators' opinions of us are affected by many factors, including system reliability and safety, protection of customer information, rates, media coverage, and public sentiment. To the extent that customers, legislators, or regulators have or develop a negative opinion of us, our financial positions, results of operations and cash flows could be adversely affected.

A number of factors can affect customer satisfaction including: service interruptions or safety concerns, due to failures of equipment or facilities or from other causes, and our ability to promptly respond to such failures; our ability to safeguard sensitive customer information; and the timing and magnitude of rate increases, and volatility of rates.

Customers', legislators', and regulators' opinions of us can also be affected by media coverage, including the proliferation of social media, which may include information, whether factual or not, that damages our brand and reputation.

If customers, legislators, or regulators have or develop a negative opinion of us and our utility services, this could result in increased regulatory oversight and could affect the returns on common equity we are allowed to earn. Additionally, negative opinions about us could make it more difficult for us to achieve favorable legislative or regulatory outcomes. Negative opinions could also result in sales volumes reductions or increased use of other sources of energy. Any of these consequences could adversely affect our financial position, results of operations and cash flows.

Risks Related Primarily to Our Local Utility Business

REGULATORY ACCOUNTING RISK. In the future, we may no longer meet the criteria for continued application of regulatory accounting practices for all or a portion of our regulated operations.

If we could no longer apply regulatory accounting, we could be required to write off our regulatory assets and precluded from the future deferral of costs not recovered through rates at the time such amounts are incurred, even if we are expected to recover these amounts from customers in the future.

GAS PRICE RISK. Higher natural gas commodity prices and volatility in the price of gas may adversely affect our results of operations and cash flows.

The cost of natural gas is affected by a variety of factors, including weather, changes in demand, the level of production and availability of natural gas supplies, transportation constraints, availability and cost of pipeline capacity, federal and state energy and environmental regulation and legislation, natural disasters and other catastrophic events, national and worldwide economic and political conditions, and the price and availability of alternative fuels. In our utility segment, the cost we pay for natural gas is generally passed through to our customers through an annual PGA rate adjustment. If gas prices were to increase significantly, it would raise the cost of energy to

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our utility customers, potentially causing those customers to conserve or switch to alternate sources of energy. Significant price increases could also cause new home builders and commercial developers to select alternative energy sources. Decreases in the volume of gas we sell could reduce our earnings, and a decline in customers could slow growth in our future earnings. Additionally, because a portion of any 10% or 20% difference between the estimated average PGA gas cost in rates and the actual average gas cost incurred is recognized as current income or expense, higher average gas costs than those assumed in setting rates can adversely affect our operating cash flows, liquidity and results of operations. Additionally, notwithstanding our current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce rates, which also could adversely affect our results of operations and cash flows.

Higher gas prices may also cause us to experience an increase in short-term debt and temporarily reduce liquidity because we pay suppliers for gas when it is purchased, which can be in advance of when these costs are recovered through rates. Significant increases in the price of gas can also slow our collection efforts as customers experience increased difficulty in paying their higher energy bills, leading to higher than normal delinquent accounts receivable resulting in greater expense associated with collection efforts and increased bad debt expense.

CUSTOMER GROWTH RISK. Our utility margin, earnings and cash flow may be negatively affected if we are unable to sustain customer growth rates in our local gas distribution segment.

Our utility margins and earnings growth have largely depended upon the sustained growth of our residential and commercial customer base due, in part, to the new construction housing market, conversions of customers to natural gas from other energy sources and growing commercial use of natural gas. The last recession slowed new construction. While construction has resumed, it has not returned to the pre-recession pace and has been heavily multi-family, which is a segment that has historically used natural gas less frequently. Insufficient growth in these markets, for economic, political or other reasons could result in an adverse long-term impact on our utility margin, earnings and cash flows.

RISK OF COMPETITION. Our gas distribution business is subject to increased competition which could negatively affect our results of operations.

In the residential and commercial markets, our gas distribution business competes primarily with suppliers of electricity, fuel oil, and propane. In the industrial market, we compete with suppliers of all forms of energy. Competition among these forms of energy is based on price, efficiency, reliability, performance, market conditions, technology, environmental impacts and public perception.

Technological improvements in other energy sources such as heat pumps, batteries or other alternative technologies could erode our competitive advantage. If natural gas prices

rise relative to other energy sources, or if the cost, environmental impact or public perception of such other energy sources improves relative to natural gas, it may negatively affect our ability to attract new customers or retain our existing residential, commercial and industrial customers, which could have a negative impact on our customer growth rate and results of operations.

RELIANCE ON THIRD PARTIES TO SUPPLY NATURAL GAS RISK. We rely on third parties to supply the natural gas in our distribution segment, and limitations on our ability to obtain supplies, or failure to receive expected supplies for which we have contracted, could have an adverse impact on our financial results.

Our ability to secure natural gas for current and future sales depends upon our ability to purchase and receive delivery of supplies of natural gas from third parties. We, and in some cases, our suppliers of natural gas do not have control over the availability of natural gas supplies, competition for those supplies, disruptions in those supplies, priority allocations on transmission pipelines, or pricing of those supplies. Additionally, third parties on whom we rely may fail to deliver gas for which we have contracted. If we are unable to obtain, or are limited in our ability to obtain, natural gas from our current suppliers or new sources, we may not be able to meet our customers' gas requirements and would likely incur costs associated with actions necessary to mitigate services disruptions, both of which could significantly and negatively impact our results of operations.

SINGLE TRANSPORTATION PIPELINE RISK. We rely on a single pipeline company for the transportation of gas to our service territory, a disruption of which could adversely impact our ability to meet our customers' gas requirements.

Our distribution system is directly connected to a single interstate pipeline, which is owned and operated by Northwest Pipeline. The pipeline's gas flows are bi-directional, transporting gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from the Alberta and the U.S. Rocky Mountain supply basins. If there is a rupture or inadequate capacity in the pipeline, we may not be able to meet our customers' gas requirements and we would likely incur costs associated with actions necessary to mitigate service disruptions, both of which could significantly and negatively impact our results of operations.

WEATHER RISK. Warmer than average weather may have a negative impact on our revenues and results of operations.

We are exposed to weather risk primarily in our utility segment. A majority of our volume is driven by gas sales to space heating residential and commercial customers during the winter heating season. Current utility rates are based on an assumption of average weather. Warmer than average weather typically results in lower gas sales. Colder weather typically results in higher gas sales. Although the effects of warmer or colder weather on utility margin in Oregon are expected to be mitigated through the operation of our weather normalization mechanism, weather variations from normal could adversely affect utility margin because we may be required to purchase more or less gas at spot rates,

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which may be higher or lower than the rates assumed in our PGA. Also, a portion of our Oregon residential and commercial customers (usually less than 10%) have opted out of the weather normalization mechanism, and 11% of our customers are located in Washington where we do not have a weather normalization mechanism. These effects could have an adverse effect on our financial condition, results of operations and cash flows.

CUSTOMER CONSERVATION RISK. Customers' conservation efforts may have a negative impact on our revenues.

An increasing national focus on energy conservation, including improved building practices and appliance efficiencies may result in increased energy conservation by customers. This can decrease our sales of natural gas and adversely affect our results of operations because revenues are collected mostly through volumetric rates, based on the amount of gas sold. In Oregon, we have a conservation tariff which is designed to recover lost utility margin due to declines in residential and small commercial customers' consumption. However, we do not have a conservation tariff in Washington that provides us this margin protection on sales to customers in that state.

RELIANCE ON TECHNOLOGY RISK. Our efforts to integrate, consolidate and streamline our operations have resulted in increased reliance on technology, the failure or security breach of which could adversely affect our financial condition and results of operations.

Over the last several years we have undertaken a variety of initiatives to integrate, standardize, centralize and streamline our operations. These efforts have resulted in greater reliance on technological tools such as: an enterprise resource planning system, an automated dispatch system, an automated meter reading system, a customer information system, a web-based ordering and tracking system, and other similar technological tools and initiatives. The failure of any of these or other similarly important technologies, or our inability to have these technologies supported, updated, expanded or integrated into other technologies, could adversely impact our operations. We take precautions to protect our systems, but there is no guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems are adequate to safeguard against all security breaches. Our utility could experience breaches of security pertaining to sensitive customer, employee and vendor information maintained by the utility in the normal course of business which could adversely affect the utility's reputation, diminish customer confidence, disrupt operations, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation, any of which could adversely affect our financial condition and results of operations.

Furthermore, we rely on information technology systems in our operations of our distribution and storage operations. There are various risks associated with these systems, including, hardware and software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data,

unauthorized control through electronic means, programming mistakes and other inadvertent errors or deliberate human acts. In particular, cyber security attacks, terrorism or other malicious acts could damage, destroy or disrupt all of our business systems. Any failure of information technology systems could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or obtain specific insurance coverage against potential losses.

Risks Related Primarily to Our Gas Storage Businesses

LONG-TERM LOW OR STABILIZATION OF GAS PRICE RISK. Any significant stabilization of natural gas prices or long-term low gas prices could have a negative impact on the demand for our natural gas storage services, which could adversely affect our financial results.

Storage businesses benefit from price volatility, which impacts the level of demand for services and the rates that can be charged for storage services. Largely due to the abundant supply of natural gas made available by hydraulic fracturing techniques, natural gas prices have dropped significantly to levels that are near historic lows. If prices and volatility remain low or decline further, then the demand for storage services, and the prices that we will be able to charge for those services, may decline or be depressed for a prolonged period of time. Prices below the costs to operate the storage facility could result in a decision to shut in all or a portion of the facility. A sustained decline in these prices or a shut-in of all or a portion of the facility could have an adverse impact on our financial condition, results of operations and cash flows.

NATURAL GAS STORAGE COMPETITION RISK. Increasing competition in the natural gas storage business could reduce the demand for our storage services and drive prices down for storage, which could adversely affect our financial condition, results of operations and cash flows.

Our natural gas storage segment competes primarily with other storage facilities and pipelines. Natural gas storage is an increasingly competitive business, with the ability to expand or build new storage capacity in California, the U.S. Rocky Mountains and elsewhere in the United States and Canada. Increased competition in the natural gas storage business could reduce the demand for our natural gas storage services, drive prices down for our storage business, and adversely affect our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows, which could adversely affect our financial condition, results of operations and cash flows.

IMPAIRMENT OF LONG-LIVED ASSETS RISK. If storage pricing does not improve, or higher value customers are not obtained, our Gill Ranch storage asset may be impaired, which could have a material effect on our financial condition, or results of operations.

We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. The determination of recoverability is based on the undiscounted net cash flows expected to result from the operation of such assets. Projected cash flows depend on the future operating costs associated with the asset, storage pricing, the ability to contract with higher value customers, and the future market and price for gas storage over the remaining life of the asset. Sustained low gas storage prices, the failure to contract with higher value customers, or operating costs that are above revenues from the facility could result in an impairment of the carrying value of our Gill Ranch storage facility, which was $196.9 million at December 31, 2016. Similarly, if we were to determine to sell the Gill Ranch storage facility, such determination may result in an impairment of the carrying value of the facility. Any impairment charge taken by the Company with respect to its long-lived assets, including Gill Ranch, could be material and could have a material effect on the Company's financial condition and results of operations.

THIRD-PARTY PIPELINE RISK. Our gas storage businesses depend on third-party pipelines that connect our storage facilities to interstate pipelines, the failure or unavailability of which could adversely affect our financial condition, results of operations and cash flows.

Our gas storage facilities are reliant on the continued operation of a third-party pipeline and other facilities that provide delivery options to and from our storage facilities. Because we do not own all of these pipelines, their operations are not within our control. If the third-party pipeline to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the infrastructure, lack of capacity or other reasons, our ability to operate efficiently and satisfy our customers' needs could be compromised, thereby potentially having an adverse impact on our financial condition, results of operations and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments.

ITEM 2. PROPERTIES

Utility Properties

Our natural gas pipeline system consists of approximately 14,000 miles of distribution and transmission mains located in our service territory in Oregon and Washington. In addition, the pipeline system includes service pipelines, meters and regulators, and gas regulating and metering stations. Pipeline mains are located in municipal streets or alleys pursuant to franchise or occupation ordinances, in county roads or state highways pursuant to agreements or permits granted pursuant to statute, or on lands of others pursuant to easements obtained from the owners of such lands. We also hold permits for the crossing of numerous navigable waterways and smaller tributaries throughout our entire service territory.

We own service building facilities in Portland, as well as various satellite service centers, garages, warehouses, and other buildings necessary and useful in the conduct of our business. We also lease office space in Portland for our corporate headquarters, which expires on May 31, 2020. Resource centers are maintained on owned or leased

premises at convenient points in the distribution system to provide service within our utility service territory. We also own LNG storage facilities in Portland and near Newport, Oregon.

Gas Storage Properties

We hold leases and other property interests in approximately 12,000 net acres of underground natural gas storage in Oregon and approximately 5,000 net acres of underground natural gas storage in California, and easements and other property interests related to pipelines associated with those facilities. We own rights to depleted gas reservoirs near Mist, Oregon, that are continuing to be developed and operated as underground gas storage facilities. We also hold an option to purchase future storage rights in certain other areas of the Mist gas field in Oregon, as well as in California related to the Gill Ranch storage facility.

We consider all of our properties currently used in our operations, both owned and leased, to be well maintained, in good operating condition, and, along with planned additions, adequate for our present and foreseeable future needs.

Our Mortgage and Deed of Trust (Mortgage) is a first mortgage lien on substantially all of the property constituting our utility plant.

ITEM 3. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 15, we have only nonmaterial litigation in the ordinary course of business.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed and trades on the New York Stock Exchange under the symbol NWN. The high and low trades for our common stock during the past two years were as follows:

	2016		2015	
Quarter Ended	High	Low	High	Low
March 31	$54.51	$48.90	$52.25	$43.35
June 30	64.84	49.46	49.77	41.32
September 30	66.17	57.96	46.74	42.00
December 31	61.85	53.50	51.85	45.03

The closing price for our common stock on December 31, 2016 and 2015 was $59.80 and $50.61, respectively.

As of February 17, 2017, there were 5,459 holders of record of our common stock.

Dividends per share paid during the past two years were as follows:

Payment Month	2016	2015
February	$0.4675	$0.4650
May	0.4675	0.4650
August	0.4675	0.4650
November	0.4700	0.4675
Total per share	$1.8725	$1.8625

The declaration and amount of future dividends depend upon our earnings, cash flows, financial condition, and other factors. The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. Subject to Board approval, we expect to continue paying cash dividends on our common stock on a quarterly basis.

The following table provides information about purchases of our equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934 during the quarter ended December 31, 2016:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(2)]	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs[(2)]
Balance forward			2,124,528	$ 16,732,648
10/01/16-10/31/16	1,264	$ 58.31	—	—
11/01/16-11/30/16	17,313	56.66	—	—
12/01/16-12/31/16	1,076	60.33	—	—
Total	19,653	56.97	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2016, 18,352 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, 1,301

shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended December 31, 2016, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2017 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended December 31, 2016, 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.

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ITEM 6. SELECTED FINANCIAL DATA

	For the year ended December 31,				
In thousands, except share data	2016	2015	2014	2013	2012
Operating revenues	$675,967	$723,791	$754,037	$758,518	$730,607
Net income	58,895	53,703	58,692	60,538	58,779
Earnings per share of common stock:					
Basic	$2.13	$1.96	$2.16	$2.24	$2.19
Diluted	2.12	1.96	2.16	2.24	2.18
Dividends paid per share of common stock	1.87	1.86	1.85	1.83	1.79
Total assets, end of period	$3,079,801	$3,069,410	$3,056,326	$2,960,808	$2,802,046
Total equity	850,497	780,972	767,321	751,872	729,627
Long-term debt	679,334	569,445	613,095	671,643	680,626

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ITEM 7. 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 years ended December 31, 2016, 2015, and 2014. References in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in Item 8 of this report.

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 disallowances related to the OPUC's 2015 and 2016 environmental orders, 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 these disallowances 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.

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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" below for more information. Highlights for the year include:

- added over 10,700 customers during the past twelve months for a growth rate of 1.5% at December 31, 2016;
- invested $140 million in our distribution system and facilities for growth and reliability, as well as for our North Mist gas storage expansion project;
- received approval to begin construction of our $128 million North Mist gas storage expansion project with a target in-service date of the winter of 2018-19;
- continued our legacy of excellent customer service with the highest residential customer satisfaction score among large utilities in the West and the second highest residential score in the nation in the 2016 J.D. Power Gas Utility Customer Satisfaction study;
- ranked first in the West and posted the second highest score in the nation in the 2016 J.D. Powers' Gas Utility Business Customer Satisfaction Study;
- reduced residential customer rates to the lowest level in 15 years with a rate reduction effective November 1, 2016, as well as a credit of $19.4 million to customers in June 2016; and
- delivered increasing dividends for the 61st consecutive year.

Key financial highlights include:

In millions, except per share data	2016 Amount	2016 Per Share	2015 Amount	2015 Per Share	2014 Amount	2014 Per Share
Consolidated net income	$58.9	$2.12	$53.7	$1.96	$58.7	$2.16
Adjustments:						
Regulatory environmental disallowance, net of taxes ($1.3, $5.9, and $0.0 for 2016, 2015, and 2014 respectively)(1)	2.0	0.07	9.1	0.33	—	—
Adjusted consolidated net income(1)	$60.9	$2.19	$62.8	$2.29	$58.7	$2.16
Utility margin	$376.6		$371.4		$366.1	
Gas storage operating revenues	25.3		21.4		22.2	
ROE	7.2 %		6.9 %		7.7 %	
Adjusted ROE(1)	7.5 %		8.1 %		7.7 %	

(1) 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. Regulatory environmental disallowance of $15.0 million in 2015 is recorded in utility operations and maintenance expense. Adjusted consolidated net income and EPS and adjusted ROE 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 27.8 million, 27.4 million, and 27.2 million diluted shares for the years ended December 31, 2016, 2015, and 2014, respectively.

2016 COMPARED TO 2015. Overall, consolidated net income increased $5.2 million. The increase was primarily due to the $9.1 million after-tax charge from 2015 and a $2.0 million after-tax charge in 2016 related to the regulatory disallowances associated with a February 2015 OPUC Order and subsequent Order in our SRRM docket. See additional disclosure in the table above.

Excluding the impact of the non-cash charges from the SRRM docket in 2015 and 2016, adjusted consolidated net income decreased $1.9 million primarily due to the following factors:

- a $7.0 million increase in operating and maintenance expense primarily due to cost savings initiatives that were implemented in the second half of 2015 that did not recur in 2016; and
- a $5.5 million decrease in other income (expense), net primarily related to the recognition of $5.3 million of equity earnings on deferred regulatory asset balances as a result of the 2015 OPUC Order; partially offset by
- a $5.2 million increase in utility margin primarily due to customer growth and gains from gas cost incentive sharing; and
- a $3.9 million increase in gas storage revenues largely due to higher revenues from our asset management

agreements at both storage facilities and slightly higher contract values at our Gill Ranch facility for the 2016-17 gas year.

2015 COMPARED TO 2014. Overall, consolidated net income decreased $5.0 million primarily due to the $9.1 million after-tax charge related to the February 2015 OPUC Order previously discussed. Excluding the impact of this Order, adjusted consolidated net income increased $4.1 million primarily due to the following factors:

- a $5.3 million increase in utility margin primarily due to customer growth and gas cost sharing, partially offset by the effects of warmer weather; and
- a $5.8 million increase in other income (expense), net related to the recognition of equity earnings on deferred regulatory asset balances as a result of the OPUC SRRM Order; partially offset by
- a $5.5 million increase in operations and maintenance expense mainly due to higher compensation and benefits expense; and
- a $0.9 million decrease in gas storage operating revenues due to negative impacts of decreases in storage prices between the 2013-14 and 2014-15 gas years; and
- a $1.7 million increase in depreciation and amortization expenses due to additional utility capital expenditures.

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2017 OUTLOOK

Our near-term outlook is centered on six long-term strategic objectives (1) delivering natural gas safely and reliably to our customers; (2) providing superior customer service; (3) working closely with policymakers and regulators to constructively meet the interests of all parties; (4) enabling continued utility growth; (5) leveraging the benefits of natural gas and our modern system to lead our region to a low-carbon future; and (6) strategically investing in our existing utility and gas storage businesses, as well as creating new ideas to drive future growth opportunities and to ensure long-term profitability.

Our 2017 goals leverage our resources and history of innovation to continue meeting the evolving needs of customers, regulators, and shareholders.

Deliver Gas	Grow Our Businesses
Ensure Safe and Reliable Service	Enable Utility Growth
Provide a Superior Customer Experience	Lead in a Low-Carbon Future
Advance Constructive Policies and Regulation	Pursue Strategic Investments

SAFETY AND RELIABILITY. Delivering natural gas safely and reliably to customers is our first priority. During 2017, we will maintain our vigilant focus on safety and emergency response training for our employees, third-party contractors, and local authorities. We will continue to strive to increase public awareness of natural gas safety and protocols to reduce damages to our critical infrastructure. Continued investment in our pipeline system and facilities is also planned to ensure reliability with multi-year projects at our LNG facilities and Mist storage facility, as well as system upgrades in high-growth areas such as Clark County, Washington. Finally, safety also includes our continuous maintenance of strong cybersecurity defenses and preparation for large-scale emergency events, such as seismic hazards in our region.

SUPERIOR CUSTOMER EXPERIENCE. NW Natural has a legacy of providing excellent customer service with consistently high rankings in the J.D. Power and Associates customer satisfaction studies and a long-standing dedication to continuous improvement. In 2017, we will continue evolving to meet our customers' changing expectations by examining our customer interactions and touchpoints as well as the technology supporting these processes. We expect this comprehensive effort to propel further use of our innovative online customer connection portal and the latest technology, providing customers with an enhanced experience while improving operational efficiencies.

POLICIES AND REGULATION. Constructive policies and regulation provide the best outcomes for both customers and shareholders. In 2017, we plan to work closely with policymakers and regulators to plan for growth of our utility, and evaluate the investments necessary for this growth in our IRP. Finally, we will continue working with the EPA and other stakeholders on an environmentally protective and cost effective clean-up for the Portland Harbor Superfund Site.

UTILITY GROWTH. Natural gas is a preferred energy choice in our service territory due to its efficiency and affordability coupled with our exceptional service. In 2017, we will continue leveraging these key attributes to capitalize on our region's above-average economic growth. We remain focused on maintaining our strong market share in the single-family residential sector, as well as capturing new commercial customers. As our Portland, Oregon community continues to experience in-migration and greater urban density, multifamily housing construction continues to outpace historical levels. Seeing this trend, we have launched a comprehensive effort to make inroads in the multifamily market with streamlined infrastructure designs, engineering technical support, and incentives and promotional support for qualifying projects. We will continue pursuing this sector in 2017.

LOW-CARBON PATHWAY. The Pacific Northwest and NW Natural are deeply committed to a clean energy future. In 2017, we will continue pursuing opportunities for carbon emission savings for both our Company and the greater region. Driving greater emission reductions over time will require leveraging our modern pipeline systems in new ways, working closely with customers, policymakers and regulators, and embracing cutting-edge technology. In 2017, we will explore ways to reduce the carbon intensity of our product with plans to also help our customers reduce and offset their consumption, and support our communities' efforts to replace more carbon intensive fuels with natural gas.

STRATEGIC INVESTMENTS. We remain focused on creating value in all our businesses. For our utility business, we are investing in the expansion of our Mist gas storage facility to provide innovative no-notice gas storage service for a single customer who will use the reliability of natural gas to integrate more intermittent renewable energy — like solar and wind — into the energy grid. We are pleased to be supporting the elimination of coal-fired electric generation renewables with this unique service. In addition, we remain focused on our non-utility businesses, including our gas storage business, and identifying higher value customers, enhanced service offerings, and seeking to capitalize on opportunities that fit our business-risk profile.

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DIVIDENDS

Dividend highlights include:

Per common share	2016	2015	2014
Dividends paid	$1.87	$1.86	$1.85

The Board of Directors declared a quarterly dividend on our common stock of $0.47 cents per share, payable on February 15, 2017, to shareholders of record on January 31, 2017, reflecting an indicated annual dividend rate of $1.88 per share.

RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation by the OPUC, WUTC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and WUTC also regulate 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 the 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 2016, we were involved in the regulatory activities discussed below.

ENVIRONMENTAL COST DEFERRAL AND SITE REMEDIATION AND RECOVERY MECHANISM (SRRM). In February 2015, as part of the implementation of the SRRM, the OPUC issued an Order (2015 Order) requiring us to forego collection of $15 million out of approximately $95 million in total environmental remediation expenses and associated carrying costs we had deferred through 2012 based on the OPUC's determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for other factors the OPUC deemed relevant. As a result, we recognized a $15.0 million non-cash charge in operations and maintenance expense in the first quarter of 2015. Also, as a result of the 2015 Order, we recognized $5.3 million pre-tax of interest income related to the equity earnings on our deferred environmental expenses in the first quarter of 2015.

In addition, the OPUC issued a subsequent Order regarding our SRRM (2016 order) in January 2016 in which the OPUC: (1) disallowed the recovery of $2.8 million of interest earned on the previously disallowed environmental expenditure amounts; (2) clarified the state allocation of 96.68% of environmental remediation costs for all environmental sites to Oregon; and (3) confirmed our treatment of $13.8 million of expenses put into the SRRM amortization account was correct and in compliance with prior OPUC orders. As a result of the 2016 Order, we recognized a $3.3 million non-cash charge, of which $2.8 million is reflected in other income and expense, net and $0.5 million is included in operations and maintenance expense. Our compliance filing related to the 2016 Order was filed with the OPUC on March 11, 2016. We do not expect any further action by the OPUC related to that filing. See Note 15 regarding our SRRM.

SYSTEM INTEGRITY PROGRAM (SIP). We filed a request to extend the SIP program in the fourth quarter of 2014. The OPUC considered our renewal request at a public meeting in March 2015 and suspended our filing and ordered additional process, including involvement of other gas utilities in the state, before making a final decision. In 2016, we withdrew our request to extend the SIP program and

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instead focused our efforts on establishing guidelines for future safety cost trackers with the OPUC. An all-party agreement was filed with the OPUC on October 10, 2016 and is currently under review. We expect resolution of this docket in the first half of 2017.

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 is also conducting an investigation into the hedging practices of gas utilities operating in Washington, and considering whether it should require gas utilities to implement certain practices related to hedging. The WUTC received comments from all parties in the first half of 2016 and continues to review the comments and docket. After the WUTC completes their review, they will determine next steps in the docket.

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 January 2017, all parties agreed and selected a third-party consultant to perform the study and are continuing to facilitate completion of the work directed by the OPUC.

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.

WEATHER NORMALIZATION MECHANISM (WARM). In Oregon, WARM is applied to residential and commercial customers' bills to adjust for temperature variances from average weather. In 2015, the OPUC initiated a review of the WARM mechanism as a result of customer complaints received related to surcharges applied under the WARM mechanism due to the record warm weather in our service territory during the 2014-15 winter. In May 2016, we filed a stipulation among the parties to resolve the issues identified in the review. In June 2016, the OPUC issued an order

adopting the stipulation, which included modest changes to the WARM mechanism. The most notable change relates to the timing of collection of any unbilled WARM amounts, due to operation of certain caps on monthly bills in the program. Previously, any unbilled WARM amounts deferred through the WARM period were billed to customers in June. Under the adjusted WARM mechanism, the collections of any unbilled WARM amounts will continue to be deferred and will earn a carrying charge until collected in the PGA the following year. These changes do not reduce the value WARM provides to us or our customers in mitigating the impact from variations in weather.

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 of 2016, in relation to our IRP in Washington and acknowledgment by the OPUC in February of 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. NW Natural is assisting the OPUC with an investigation regarding the incident.

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. As one of only two local distribution companies remaining without a holding company structure, we recognize the advantages and flexibility inherent in such a structure and are exploring the possibility of such a reorganization. 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. Once regulatory conditions and approvals are obtained, our Board of Directors will evaluate the desirability of a holding company structure in light of the conditions imposed. If supported by the Board of Directors, we would then submit the proposed corporate reorganization to our shareholders for approval. If approved by the shareholders, corporate filings would be made that would create the holding company, with the shareholders immediately prior to the reorganization owning the same relative percentages of the holding company as they own of NW Natural immediately prior to the reorganization. The structure currently contemplated involves placing a non-operating corporate entity over our existing consolidated structure. If we were to determine that this reorganization were not desirable at any point in the process, the corporation reorganization would not proceed. We do not expect a material operational or financial impact to our business as a result of the contemplated reorganization.

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.

We filed our PGA in September 2016 and received OPUC and WUTC approval in October 2016. PGA rate changes were effective November 1, 2016. The rate changes decreased the average monthly bills of residential customers by approximately 2.6% and 1.5% in Oregon and Washington, respectively. The decrease in Oregon reflects customers' portion of adjustments for changes in wholesale natural gas costs, offset by adjustments related to the decoupling mechanism, environmental costs, and additional annual adjustments based on ongoing orders with the OPUC. Washington rates reflected the effect of changes in wholesale natural gas costs, offset by slight increases in certain energy efficiency programs. In addition, we credited $19.4 million to customers in June 2016 for their portion of the gas cost sharing incentive for the 2015-2016 gas year, resulting from lower than projected gas costs, which were driven by warmer than normal weather, lower volume usage, and lower market prices.

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. .

In addition to the amount hedged for the current gas contract year, we are also hedged in future years at approximately 26% for the 2017-18 gas year and between 4% and 18% for annual requirements over the subsequent five gas years as of December 31, 2016. 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 2014-15, 2015-16, and 2016-17 periods, we selected the 90%, 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 2014, 2015, and 2016, the ROE threshold was 10.66%, 10.60%, and 11.06%, respectively. There were no refunds required for 2014 and 2015. We do not expect a refund for 2016 based on our results and anticipate filing the 2016 earnings test in May 2017.

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 elected to participate in some of the additional wells drilled in 2014, but did not have the opportunity to participate in additional wells in 2015 and 2016. In the future, we may have the opportunity to participate in additional wells. Volumes produced from the additional wells drilled in 2014 are included in our Oregon PGA at a fixed rate of $0.4725

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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. 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 December 31, 2016, 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. In Oregon, we have a SRRM through which we track and have the ability to recover prudently incurred past deferred and future environmental remediation costs allocable to Oregon, subject to an earnings test.

The SRRM defines three classes 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. We included

$10.0 million of deferred remediation expense approved by the OPUC for collection during the 2016-2017 PGA year.

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[(1)]
Prior year carry-over[(2)]
$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[(3)]
Total amount transferred to post-review

(1) Base rate rider went into Oregon customer rates beginning November 1, 2015.
(2) 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.
(3) Deferred interest is added to annual spend to the extent the spend is recoverable.

If the adjusted utility ROE is greater than the authorized utility ROE, then we could be required to expense amounts in excess of authorized ROE.

For 2016, we have performed this test, which we anticipate submitting to the OPUC in May 2017, and we do not expect an earnings test adjustment for 2016.

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 a carrying charge to be determined in a future proceeding.

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

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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 $6.3 million, $8.2 million, and $4.6 million in 2016, 2015 and 2014, respectively. See "Application of Critical Accounting Policies and Estimates" below.

INTERSTATE STORAGE AND OPTIMIZATION SHARING. On an annual basis, we credit amounts to Oregon and Washington customers as part of our regulatory incentive sharing mechanism related to net revenues earned from Mist gas storage and asset management activities. Generally amounts are credited to Oregon customers in June, while credits are given to customers in Washington through reductions in rates through the annual PGA filing in November.

following table presents the credits to customers:

In millions	2016	2015	2014
Oregon utility customer credit	$9.4	$9.6	$11.4
Washington utility customer credit	1.0	0.8	0.8

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 the volatility of customer bills and our utility's earnings. See "Regulatory Matters—Rate Mechanisms" above.

Utility segment highlights include:

Dollars and therms in millions, except EPS data	2016	2015	2014
Utility net income	$54.6	$53.4	$58.6
EPS - utility segment	1.96	1.95	2.15
Gas sold and delivered (in therms)	1,085	1,029	1,093
Utility margin[1]	$376.6	$371.4	$366.1

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

2016 COMPARED TO 2015. The primary factors contributing to the $1.2 million or $0.01 per share increase in utility net income were as follows:

- a $5.2 million increase in utility margin primarily due to:
  - a $5.7 million increase from customer growth;
  - a $0.8 million increase from gains in gas cost incentive sharing resulting from lower gas prices than those estimated in the PGA; partially offset by
  - a $1.3 million decrease due to lower contributions from our gas reserve investments, which decreased due to amortization.
-

- an $8.3 million decrease in operations and maintenance expense primarily due to the environmental disallowance recognized in 2015, offset in part by increases in payroll costs due to additional headcount and general pay increases along with increased non-payroll costs for professional services and contract work; partially offset by
- an $8.7 million decrease in other income (expense), net, primarily due to the environmental interest disallowance recognized in 2016 and the recognition of $5.3 million of equity earnings on deferred regulatory asset balances in 2015; and
- a $1.9 million increase in depreciation expense primarily due to additional capital expenditures.

Total utility volumes sold and delivered in 2016 increased 5% over 2015 primarily due to comparatively colder weather in the first quarter during our peak heating season and colder weather in December 2016.

2015 COMPARED TO 2014. The primary factors contributing to the $5.2 million or $0.20 per share decrease in utility net income were as follows:

- the $15 million pre-tax charge, or $9.1 million after-tax charge, for the regulatory disallowance associated with the February 2015 OPUC Order on the recovery of past environmental cost deferrals. This charge is reflected in operations and maintenance expense;
- a $5.3 million increase in utility margin primarily due to:
  - a $4.4 million increase from customer growth;
  - a $5.3 million increase from gas cost incentive sharing resulting from lower gas prices than those estimated in the PGA; partially offset by
  - an approximate $4.0 million decrease due to lower customer usage from warmer weather, which impacts utility margins from our Washington customers where we do not have a weather normalization mechanism in place, and from our Oregon customers who opted out of weather normalization.
- a $6.6 million increase in other income (expense), net, primarily due to the recognition of the equity earnings on deferred environmental expenditures as a result of the February order;
- a $7.2 million increase in operations and maintenance expense, excluding the environmental disallowance, primarily due to an increase in compensation and benefit expense; and
- a net $0.4 million increase in other expenses related to increased depreciation expense from additional capital investments and an increase in general taxes from higher Oregon property tax expense, offset by a decrease in interest expense due to debt redemptions made during the year.

Total utility volumes sold and delivered in 2015 decreased 6% over 2014 primarily due to the impact of warmer weather.

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

In thousands, except degree day and customer data	2016	2015	2014	Favorable/(Unfavorable) 2016 vs. 2015	Favorable/(Unfavorable) 2015 vs. 2014
Utility volumes (therms):					
Residential and commercial sales	609,222	570,728	620,903	38,494	(50,175)
Industrial sales and transportation	475,774	457,884	472,087	17,890	(14,203)
Total utility volumes sold and delivered	1,084,996	1,028,612	1,092,990	56,384	(64,378)
Utility operating revenues:					
Residential and commercial sales	$604,390	$644,835	$672,440	$(40,445)	$(27,605)
Industrial sales and transportation	59,386	71,495	73,992	(12,109)	(2,497)
Other revenues	3,812	3,914	3,983	(102)	(69)
Less: Revenue taxes	17,111	18,034	18,837	(923)	(803)
Total utility operating revenues	650,477	702,210	731,578	(51,733)	(29,368)
Less: Cost of gas	260,588	327,305	365,490	66,717	38,185
Less: Environmental remediation expense	13,298	3,513	—	(9,785)	(3,513)
Utility margin	$376,591	$371,392	$366,088	$5,199	$5,304
Utility margin:[1]					
Residential and commercial sales	$338,060	$334,134	$334,247	$3,926	$(113)
Industrial sales and transportation	30,989	30,081	29,982	908	99
Miscellaneous revenues	3,796	3,913	4,329	(117)	(416)
Gain (loss) from gas cost incentive sharing	3,960	3,182	(2,135)	778	5,317
Other margin adjustments	(214)	82	(335)	(296)	417
Utility margin	$376,591	$371,392	$366,088	$5,199	$5,304
Degree days					
Average[2]	4,256	4,240	4,240	16	—
Actual	3,551	3,458	3,792	3%	(9)%
Percent colder (warmer) than average weather[2]	(17)%	(18)%	(11)%		
Customers - end of period:					
Residential customers	656,855	646,841	637,411	10,014	9,430
Commercial customers	67,278	66,584	66,304	694	280
Industrial customers	1,013	1,003	929	10	74
Total number of customers	725,146	714,428	704,644	10,718	9,784
Customer growth:					
Residential customers	1.5%	1.5%			
Commercial customers	1.0%	0.4%			
Industrial customers	1.0%	8.0%			
Total customer growth	1.5%	1.4%			

(1) 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.

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

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Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, energy prices, competition from other energy sources, and economic conditions in our service areas. The impact of weather on margin is significantly reduced through our weather normalization mechanism in Oregon; approximately 80% of our total customers are covered under this mechanism. The remaining customers either opt out of the mechanism or are located in Washington, which does not have a similar mechanism in place. For more information on our weather mechanism, see "Regulatory Matters—Rate Mechanisms—Weather Normalization Mechanism" above.

Residential and commercial sales highlights include:

In millions	2016	2015	2014
Volumes (therms):			
Residential sales	379.2	350.9	381.5
Commercial sales	230.0	219.8	239.4
Total volumes	609.2	570.7	620.9
Operating revenues:			
Residential sales	$404.3	$424.6	$441.5
Commercial sales	200.1	220.2	230.9
Total operating revenues	$604.4	$644.8	$672.4
Utility margin:			
Residential:			
Sales	$223.2	$211.6	$223.6
Weather normalization	12.7	14.0	5.1
Decoupling	0.8	7.2	4.0
Total residential utility margin	236.7	232.8	232.7
Commercial:			
Sales	87.2	84.8	91.6
Weather normalization	5.0	5.8	2.2
Decoupling	9.2	10.7	7.7
Total commercial utility margin	101.4	101.3	101.5
Total utility margin	$338.1	$334.1	$334.2

2016 COMPARED TO 2015. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 38.5 million therms, or 7%, due to customer growth and comparatively colder weather in the first quarter and December of 2016 compared to record warm weather in 2015;
- operating revenues decreased $40.4 million, due to a 24% decrease in average cost of gas over last year, partially offset by a 7% increase in sales volumes; and
- utility margin increased $4.0 million, due to both residential and commercial customer growth offset by lower contributions from our gas reserve investments, which decreased due to amortization.

2015 COMPARED TO 2014. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes decreased 50.2 million therms, or 8%, primarily reflecting 9% warmer weather, which was partially offset by customer growth;

- operating revenues decreased $27.6 million, due to the 8% decrease in sales volumes, as well as a 2% decrease in average gas rates over last year; and
- utility margin decreased $0.1 million, due to warmer weather, almost entirely offset by increases from commercial and residential customer growth.

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:

In millions	2016	2015	2014
Volumes (therms):			
Industrial - firm sales	33.8	32.4	34.0
Industrial - firm transportation	156.9	144.0	153.6
Industrial - interruptible sales	50.4	57.3	61.6
Industrial - interruptible transportation	234.7	224.2	222.9
Total volumes	475.8	457.9	472.1
Utility margin:			
Industrial - sales and transportation	$31.0	$30.1	$30.0

2016 COMPARED TO 2015. Sales and transportation volumes increased by 17.9 million therms and utility margin increased $0.9 million due to annual customer service election changes, higher fee revenue due to system restrictions from cold weather in December 2016, and an increase in usage from a few large customers.

2015 COMPARED TO 2014. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales and transportation volumes decreased by 14.2 million therms due to lower usage from warmer weather and lower demand from a few large volume transportation customers on lower margin rate schedules;
- utility margin increased $0.1 million, primarily due to an increase in industrial customers under higher margin rate schedules partially offset by higher fee revenue in

the prior year from increased usage during the cold weather event in February 2014.

Other Revenues

Other revenues include miscellaneous fee income as well as regulatory revenue adjustments, which reflect current period deferrals to and prior year amortizations from regulatory asset and liability accounts, except for gas cost deferrals which flow through cost of gas. Decoupling amortizations and other regulatory amortizations from prior year deferrals are included in revenues from residential, commercial and industrial firm customers.

Other revenue for 2016, 2015, and 2014 remained flat year-over-year as expected.

In millions	2016	2015	2014
Other revenues	$3.8	$3.9	$4.0

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" below.

Cost of gas highlights include:

Dollars and therms in millions	2016	2015	2014
Cost of gas	$260.6	$327.3	$365.5
Volumes sold (therms)	693	660	716
Average cost of gas (cents per therm)	$0.38	$0.50	$0.51
Gain (loss) from gas cost incentive sharing	4.0	3.2	(2.1)

2016 COMPARED TO 2015. Cost of gas decreased $66.7 million, or 20%, reflecting lower natural gas prices and resulting in a $19.4 million credit to customers, partially offset by a 5% increase in volumes mainly from comparatively colder weather in the first quarter and December 2016.

2015 COMPARED TO 2014. Cost of gas decreased $38.2 million, or 10% primarily due to an 8% decrease in sales volume reflecting warmer weather during the year as well as a 2% decrease in average cost of gas reflecting lower market prices for natural gas.

The effect on net income from our gas cost incentive sharing mechanism resulted in a margin gain of $4.0 million and $3.2 million for 2016 and 2015, respectively, as prices were lower due to warmer than average weather. During the extreme cold weather event in February 2014, we experienced a record sendout and consequently, the higher volumes of gas purchased at that time resulted in a margin loss of $2.1 million. For a discussion of our gas cost incentive sharing mechanism, see “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” above.

Business Segments - Gas Storage
Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility in Oregon and our 75% undivided ownership interest in the Gill Ranch underground storage facility in California.

At Mist, we provide gas storage services to customers in the interstate and intrastate markets using storage capacity that has been developed in advance of core utility customers’ requirements. 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 business segment. Pre-tax income from gas storage at Mist and asset management services is subject to revenue sharing with core utility customers. Under this regulatory incentive sharing mechanism, we retain 80% of pre-tax income from Mist gas storage services and asset management services when the underlying costs of the capacity being used are not included in our utility rates, and 33% of pre-tax income from such storage and asset management services when the capacity being used is included in utility rates. The remaining 20% and 67%, respectively, are credited to a deferred regulatory account for credit to our core utility customers. See "Regulatory Matters—Regulatory Proceeding Updates" above for information regarding an open docket related to this incentive sharing mechanism.

Our 75% undivided ownership interest in the Gill Ranch facility is held by our wholly-owned subsidiary Gill Ranch, LLC, which is also the operator of the facility. Our portion of the facility is 15 Bcf of gas storage capacity. We also contract with an independent energy marketing company to provide asset management services at Gill Ranch. See also Note 4.

Gas storage segment highlights include:

In millions, except EPS data	2016	2015	2014
Operating revenues	25.3	21.4	22.2
Operating expenses	16.1	16.3	18.2
Gas storage net income (loss)	$4.3	$0.2	$(0.4)
EPS - gas storage segment	0.16	0.01	(0.01)

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2016 COMPARED TO 2015. Our gas storage segment net income increased $4.1 million or $0.15 per share primarily due to the following factors:

- a $3.9 million increase in operating revenue primarily from higher asset management revenues from our Mist facility and transportation capacity, and slightly higher firm contract prices at our Gill Ranch facility for the 2016-17 gas year; and
- a $2.8 million decrease in interest expense from the early retirement of $20 million of Gill Ranch debt in December 2015.

2015 COMPARED TO 2014. Our gas storage segment net income increased $0.6 million primarily due to the following offsetting factors:

- a $0.9 million decrease in operating revenues, primarily due to a decrease in storage prices between the 2013-14 and 2014-15 gas storage years; and
- a $1.9 million decrease in operating expenses primarily due to lower repair and power costs 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 completed our contracting for the 2016-17 gas storage year and have seen a slight improvement in pricing compared to the 2015-16 gas storage year.

Though prices for the 2015-16 and 2016-17 gas years have shown slight improvements at our Gill Ranch facility, they remain low relative to the pricing in 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. However, given the continued lower market prices, we are exploring a number of strategic options including opportunities to provide services to higher value customers and also seek to capitalize on opportunities that fit our business-risk profile.

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 $196.9 million at December 31, 2016. 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 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 2016. See Note 4 and Note 12 for further details on other activities and our investment in TWH.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

In millions	2016	2015	2014
Operations and maintenance	$150.0	$157.5	$137.0

2016 COMPARED TO 2015. Operations and maintenance expense decreased $7.5 million, primarily due to the following factors:

- the $15 million pre-tax charge for the regulatory disallowance associated with the February 2015 OPUC Order on the recovery of past environmental cost deferrals recorded in 2015. We also expensed an additional $1 million related to the 2015 Order; partially offset by
- a $6.5 million increase in non-payroll costs, which returned to a more sustainable level in 2016 after temporary cost savings initiatives in the prior year. Non-payroll increases were primarily related to higher professional service and contract work costs due to general customer service cost increases from system integrity work, and other maintenance; and
- a $1.2 million increase in payroll and benefits due to increased headcount and general pay increases.

2015 COMPARED TO 2014. Operations and maintenance expense increased $20.5 million, primarily due to the following factors:

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- the $15 million pre-tax charge for the regulatory disallowance associated with the February 2015 OPUC Order on the recovery of past environmental cost deferrals. We also expensed an additional $1 million related to the Order; and
- a $5.5 million increase in compensation and benefit expense, including increased employee incentive expense, retirement expense, and health care costs, as well as higher wage rates under the new union labor contract, which became effective June 1, 2014; offset by
- a $1.9 million decrease primarily related to 2014 repair and power costs at our Gill Ranch gas storage facility.

During 2015, management implemented temporary cost saving initiatives to mitigate the effects of warm weather and the $15 million regulatory disallowance. These initiatives resulted in approximately $5 million of operations and maintenance expense savings during 2015 that did not recur in 2016.

Delinquent customer receivable balances continue to remain at historically low levels. The utility's bad debt expense as a percent of revenues was 0.1% for 2016, 2015 and 2014.

In addition to fluctuations in operations and maintenance expense reported above, we have OPUC approval to defer certain utility pension costs in excess of what is currently recovered in customer rates. This pension cost deferral is recorded to a regulatory balancing account, which stabilizes the amount of operations and maintenance expense each year. For the years ended December 31, 2016, 2015 and 2014 we deferred pension expenses totaling $6.3 million, $8.2 million and $4.6 million, respectively. As a result, increased pension costs had a minimal effect on operations and maintenance expense in 2016, 2015 and 2014, with the increase principally related to the costs allocated to our Washington operations, which are not covered by the pension balancing account. For further explanation of the pension balancing account, see Note 8 and "Regulatory Matters—Rate Mechanisms—Pension Cost Deferral and Prepaid Pension Assets," above for further explanation of the pension balancing account.

Depreciation and Amortization

Depreciation and amortization highlights include:

In millions	2016	2015	2014
Depreciation and amortization	$82.3	$80.9	$79.2

2016 COMPARED TO 2015. Depreciation and amortization expense increased by $1.4 million due to utility plant additions that included investments in our natural gas transmission and distribution system, storage facilities, and technology.

2015 COMPARED TO 2014. Depreciation and amortization expense increased by $1.7 million due to utility plant additions that included natural gas transmission and distribution system investments and computer software.

Other Income (Expense), Net

Other income (expense), net highlights include:

In millions	2016	2015	2014
Gains from company-owned life insurance	$1.7	$2.2	$2.0
Interest income	0.1	0.1	0.1
Loss from equity investments	(0.1)	(0.1)	(0.2)
Net interest income (expense) on deferred regulatory accounts	(0.1)	8.2	2.4
Other non-operating	(2.1)	(2.7)	(2.4)

Total other income (expense), net	$(0.5)	$7.7	$1.9

2016 COMPARED TO 2015. Other income (expense), net, decreased $8.3 million primarily due to the recognition of $5.3 million of the equity component in interest income from our deferred environmental expenses in the prior year, which did not recur in 2016. We recognized the equity earnings of these deferred regulatory asset balances as a result of the OPUC SRRM Order we received in February 2015. In addition, a January 2016 Order from the OPUC resulted in a write-off of $2.8 million of interest during 2016.

2015 COMPARED TO 2014. Other income (expense), net, increased $5.8 million primarily due to the recognition of the equity component in interest income from our deferred environmental expenses. We realized the equity earnings of these deferred regulatory asset balances as a result of the OPUC SRRM Order we received in February 2015.

Interest Expense, Net

Interest expense, net highlights include:

In millions	2016	2015	2014
Interest expense, net	$39.1	$42.5	$44.6

2016 COMPARED TO 2015. Interest expense, net of amounts capitalized, decreased $3.4 million primarily due to the redemption of $40 million of utility First Mortgage Bonds (FMBs) in June 2015 and the early retirement of $20 million of Gill Ranch's debt in December 2015, which included a make whole interest provision.

2015 COMPARED TO 2014. Interest expense, net of amounts capitalized, decreased $2.1 million primarily due to the redemption of $40 million of utility FMBs in June 2015, $60 million of utility FMBs in 2014, and the retirement of $20 million of Gill Ranch's debt in June 2014. This was partially offset by the early retirement of $20 million of Gill Ranch's debt in December 2015, which included a make whole interest provision.

Income Tax Expense

Income tax expense highlights include:

In millions	2016	2015	2014
Income tax expense	$40.7	$35.8	$41.6
Effective tax rate	40.9 %	40.0 %	41.5 %

2016 COMPARED TO 2015. The increase in the effective income tax rate is due to lower benefits of depletion deductions from our gas reserves activity.

2015 COMPARED TO 2014. The decrease in the effective income tax rate reflects the benefits of depletion deductions from our gas reserves activity.

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 7.

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:

	December 31,	
	2016	2015
Common stock equity	52.4 %	47.5 %
Long-term debt	41.9	34.6
Short-term debt, including current maturities of long-term debt	5.7	17.9
Total	100.0%	100.0%

During 2016, changes to our capital structure were primarily due to issuances of long-term debt instruments and our equity issuance. The net proceeds from these issuances will be used for general corporate purposes, primarily to fund our ongoing utility construction programs and reduce our short-term debt. See further discussion below in "Cash Flows — Financing Activities".

Liquidity and Capital Resources

At December 31, 2016 we had $3.5 million of cash and cash equivalents compared to $4.2 million at December 31, 2015. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances and add short-term borrowing capacity. In addition, we may also pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC. Our use of retained earnings is not subject to those same restrictions.

For the utility segment, the short-term borrowing requirements typically peak during colder 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 December 31, 2016, 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 near the threshold for posting collateral at December 31, 2016. However, if the credit risk-related contingent features underlying these contracts were triggered on December 31, 2016, assuming our long-term debt ratings dropped to non-investment grade levels, we would not have been required to post collateral with our counterparties. See "Credit Ratings" below and Note 13.

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

PENSION CONTRIBUTIONS. 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" below.

BONUS DEPRECIATION. Regarding income tax, 50 percent bonus depreciation was available for a large portion of our capital expenditures in 2014, 2015 and 2016 for both federal and Oregon. This reduced taxable income and provided cash flow benefits. The federal Protecting Americans from Tax Hikes Act of 2015 became law on December 18, 2015 and extended federal bonus depreciation through 2019.

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ENVIRONMENTAL EXPENDITURES. Concerning environmental expenditures, we expect to continue using cash resources to fund our environmental liabilities. In 2015, we received an Order from the OPUC regarding our SRRM and began recovering amounts through utility rates in November 2015. In addition, the OPUC issued a subsequent Order regarding SRRM implementation in January 2016. See Note 15, and "Results of Operations—Regulatory Matters—Environmental Costs" above.

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 contract prices for the 2015-16 and 2016-17 storage 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 LIQUIDITY. 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.

DIVIDEND POLICY. We have paid quarterly dividends on our common stock each year since stock was first issued to the public in 1951. Annual common stock dividend payments per share, adjusted for stock splits, have increased each year since 1956. The declarations and amount of future dividends will depend upon our earnings, cash flows, financial condition and other factors. The amount and timing of dividends payable on our common stock is at the sole discretion of our Board of Directors.

OFF-BALANCE SHEET ARRANGEMENTS. Except for certain lease and purchase commitments, we have no material off-balance sheet financing arrangements. See "Contractual Obligations" below.

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Contractual Obligations

The following table shows our contractual obligations at December 31, 2016 by maturity and type of obligation:

	Payments Due in Years Ending December 31,						
In millions	2017	2018	2019	2020	2021	Thereafter	Total
Short-term debt maturities	$53.3	$—	$—	$—	$—	$ —	$53.3
Long-term debt maturities	40.0	97.0	30.0	75.0	60.0	424.7	726.7
Interest on long-term debt	38.4	35.4	33.7	29.5	24.4	202.7	364.1
Postretirement benefit payments(1)	24.0	25.0	25.9	26.8	27.7	146.9	276.3
Capital leases	0.2	—	—	—	—	—	0.2
Operating leases	5.5	5.4	5.3	2.8	0.9	29.0	48.9
Gas purchases(2)	78.6	—	—	—	—	—	78.6
Gas pipeline capacity commitments	85.7	83.5	77.1	72.0	46.0	296.6	660.9
Other purchase commitments(3)	64.5	8.9	0.6	—	0.1	—	74.1
Other long-term liabilities(4)	17.2	—	—	—	—	—	17.2
Total	$407.4	$255.2	$172.6	$206.1	$159.1	$ 1,099.9	$2,300.3

(1) Postretirement benefit payments primarily consists of two items: (1) estimated qualified defined benefit pension plan payments, which are funded by plan assets and future cash contributions, and (2) required payments to the Western States multiemployer pension plan due to our withdrawal from the plan in December 2013. See Note 8.

(2) Gas purchases include contracts which use price formulas tied to monthly index prices. The commitment amounts presented incorporate the December 2016 first of month index price for each supply basin from which gas is purchased. For a summary of gas purchase and gas pipeline capacity commitments, see Note 14.

(3) Other purchase commitments primarily consist of base gas requirements and remaining balances under existing purchase orders.

(4) Other long-term liabilities includes accrued vacation liabilities for management employees and deferred compensation plan liabilities for executives and directors. The timing of these payments are uncertain; however, these payments are unlikely to all occur in the next 12 months.

In addition to known contractual obligations listed in the above table, we have also recognized liabilities for future environmental remediation or action. The exact timing of payments beyond 12 months with respect to those liabilities cannot be reasonably estimated due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of site investigations. See Note 15 for a further discussion of environmental remediation cost liabilities.

At December 31, 2016, 611 of our utility employees were members of the Office and Professional Employees International Union (OPEIU) Local No. 11. In May 2014, our union employees ratified a new labor agreement (Joint Accord) that expires on November 30, 2019. The Joint Accord includes the following items: an average annualized compensation increase of 4% effective June 1, 2014, which includes a 7.9% wage increase to better reflect current market competitive wages, offset by a reduction in bonus pay opportunities for union employees; and a scheduled 3% wage increase effective December 1 each year thereafter, beginning in 2015 with the potential for up to an additional 3% per year based on wage inflation at or above 4%. The Joint Accord also maintains competitive health benefits, including a 15% to 20% premium cost sharing by employees, job flexibility, and other flexibility provisions for the Company.

Short-Term Debt
Our primary source of utility short-term liquidity is from 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 December 31, 2016 and 2015, our utility had short-term debt outstanding of $53.3 million and $270.0 million, respectively. The effective interest rate on short-term debt outstanding at December 31, 2016 and 2015 was 0.8% and 0.6%, respectively.

In the fourth quarter of 2015, we entered into a short-term credit facility loan totaling $50 million, as a short-term bridge through our peak heating season, which was repaid on February 4, 2016.

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.

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All lenders under the agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2016 as follows:

In millions

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 December 31, 2016 or 2015. 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 December 31, 2016 and 2015, with consolidated indebtedness to total capitalization ratios of 47.6% and 52.5%, respectively.

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

Credit Ratings

Our credit ratings are a factor of our liquidity, 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 Redemption of Long-Term Debt

The following debentures were retired:

	Years Ended December 31,		
In millions	2016	2015	2014
Utility First Mortgage Bonds			
3.95% Series B due 2014	$—	$—	$ 50
8.26% Series B due 2014	—	—	10
4.70% Series B due 2015	—	40	—
5.15% Series B due 2016	25	—	—
	25	40	60
Subsidiary Debt			
Variable-rate	—	—	20
Fixed-rate	—	20	—
	$25	$ 60	$ 80

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:

In millions	2016	2015	2014
Cash provided by operating activities	$222.1	$184.7	$215.7

2016 COMPARED TO 2015. The significant factors contributing to the $37.5 million increase in operating cash flows provided by operating activities were as follows:

- a net increase of $29.4 million from changes in working capital related to cold weather in December 2016 and its impact on receivables, inventories, and accounts payable; and
- an increase of $27.6 million in tax related accounts primarily due to a federal tax refund and an increase in accrued taxes and net deferred tax liabilities primarily due to the enactment of bonus depreciation;
- an increase of $17.7 million from increased cash collections from our decoupling mechanism;
- an increase of $9.8 million from collections under the SRRM; partially offset by
- a decrease of $42.1 million from changes in deferred gas cost balances due to lower natural gas prices than those embedded in the PGA, which also resulted in a $19.4 million early credit to customers’ bills in June 2016.

2015 COMPARED TO 2014. The significant factors contributing to the $31.0 million decrease in operating cash flows were as follows:

- a decrease of $99.4 million in deferred environmental recoveries, net of expenditures, reflecting the receipt of insurance settlements during 2014;
- an increase of $55.0 million from changes in deferred gas costs balances, which reflected lower actual gas prices than prices embedded in the PGA compared to the prior year;
- an increase of $15.0 million from regulatory disallowance of prior environmental cost deferrals in 2015;
- a decrease of $5.3 million from a non-cash recognition of interest income on deferred environmental expenses related to our SRRM order;
- a net decrease of $3.6 million from changes in working capital related to receivables, inventories and accounts payable due to warmer weather in 2015 compared to 2014; and
- an increase of $1.8 million from changes in regulatory balances, other assets and liabilities, and accrued taxes.

During the year ended December 31, 2016, we contributed $14.5 million to our utility's qualified defined benefit pension plan, compared to $14.1 million for 2015 and $10.5 million for 2014. The amounts and timing of future contributions will depend on market interest rates and investment returns on the plans’ assets. See Note 8.

Bonus depreciation of 50% has been available for federal and Oregon purposes in 2014, 2015 and 2016. This reduced taxable income and provided cash flow benefits. Bonus depreciation for 2014 and 2015 was not enacted until December 19, 2014 and December 18, 2015, respectively. In both cases it was extended retroactively back to January 1 of the respective year. As a result, estimated income tax payments were made throughout 2014 and 2015 without the benefit of bonus depreciation for the year. This delayed the cash flow benefit of bonus depreciation until refunds could be requested and received. We received refunds of federal income tax overpayments of $7.9 million and $2.0 million in during 2016 and 2015, respectively. 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” above and Note 14.

Investing Activities

Investing activity highlights include:

In millions	2016	2015	2014
Total cash (used in) provided by investing activities	$(136.6)	$(115.3)	$(144.3)
Capital expenditures	(139.5)	(118.3)	(120.1)

2016 COMPARED TO 2015. The $21.3 million increase in cash used in investing activities was primarily due to higher utility capital expenditures related to improvements at our Newport LNG facility in Oregon, additional infrastructure investments in Clark County, Washington, and capital expenditures for our North Mist gas storage expansion project.

2015 COMPARED TO 2014. The $29.0 million decrease in cash used in investing activities was primarily due to lower contributions from our gas reserve investments, which decrease due to regular amortization, compared to 2014 as NW Natural ended its original drilling program with Encana in 2014.

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 December 31, 2016, we had invested $21 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

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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.

Included in the five year period, 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:

In millions	2016	2015	2014
Total cash (used in) provided by financing activities	$(86.2)	$(74.7)	$(71.3)
Change in short-term debt	(216.7)	35.3	46.5
Change in long-term debt	125.0	(60.0)	(80.0)
Change in common stock issued, net	60.1	3.9	9.0

2016 COMPARED TO 2015. The $11.5 million increase in cash used in financing activities was primarily due to higher repayments of short term loans and commercial paper of $252 million, partially offset by proceeds from $150 million of long-term debt issued in December 2016 and $53 million of common stock issued in November 2016, along with a $35 million decrease in repayments of long-term debt as compared to 2015.

2015 COMPARED TO 2014. The $3.4 million increase in cash used in financing activities was primarily due to redeeming $20 million less debt in 2015 compared to 2014. Partially offsetting the increase was the issuance of $11.2 million less of net commercial paper and short-term loans in 2015 compared to 2014.

Pension Cost and Funding Status of Qualified Retirement Plans

Pension costs are determined in accordance with accounting standards for compensation and retirement benefits. See “Application of Critical Accounting Policies and Estimates – Accounting for Pensions and Postretirement Benefits” below. Pension expense for our qualified defined benefit plan, which is allocated between operations and maintenance expenses, capital expenditures, and the deferred regulatory balancing account, totaled $17.3 million in 2016, a decrease of $3.5 million from 2015. The fair market value of pension assets in this plan increased to $257.7 million at December 31, 2016 from $249.3 million at December 31, 2015. The increase was due to a return on plan assets of $12.6 million and $14.5 million in employer contributions, offset by benefit payments of $18.7 million.

We make contributions to the company-sponsored qualified defined benefit pension plan based on actuarial assumptions and estimates, tax regulations and funding

requirements under federal law. Our qualified defined benefit pension plan was underfunded by $165.8 million at December 31, 2016. We plan to make contributions during 2017 of $19.4 million. See Note 8 for further pension disclosures.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2016, 2015, and 2014, our ratios of earnings to fixed charges, computed using the method outlined by the SEC, were 3.39, 3.00, and 3.13, 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” below. At December 31, 2016, our total estimated liability related to environmental sites is $119.7 million. See Note 15 and "Results of Operations—Regulatory Matters—Rate Mechanisms—Environmental Costs" above.

New Accounting Pronouncements

For a description of recent accounting pronouncements that may have an impact on our financial condition, results of operations or cash flows, see Note 2.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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.

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.

Regulatory Accounting

Our utility is regulated by the OPUC and WUTC, which establish the rates and rules governing utility services provided to customers, and, to a certain extent, set forth special accounting treatment for certain regulatory transactions. In general, we use the same accounting principles as non-regulated companies reporting under GAAP. However, authoritative guidance for regulated operations (regulatory accounting) requires different accounting treatment for regulated companies to show the effects of such regulation. For example, we account for the cost of gas using a PGA deferral and cost recovery mechanism, which is submitted for approval annually to the OPUC and WUTC. See "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" above. There are other expenses and revenues that the OPUC or WUTC may require us to defer for recovery or refund in future periods. Regulatory accounting requires us to account for these types of deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When we are allowed to recover these regulatory assets from, or are required to refund regulatory liabilities to, customers, we recognize the expense or revenue on the income statement at the same time we realize the adjustment to amounts included in utility rates charged to customers.

The conditions we must satisfy to adopt the accounting policies and practices of regulatory accounting include:

- an independent regulator sets rates;
- the regulator sets the rates to cover specific costs of delivering service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

Because our utility satisfies all three conditions, we continue to apply regulatory accounting to our utility operations. Future accounting changes, regulatory changes or changes in the competitive environment could require us to discontinue the application of regulatory accounting for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers.

Based on current accounting and regulatory competitive conditions, we believe it is reasonable to expect continued application of regulatory accounting for our utility activities. Further, it is reasonable to expect the recovery or refund of our regulatory assets and liabilities at December 31, 2016 through future customer rates. If we should determine 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 against earnings in the period such determination is made. The net balance in regulatory asset and liability accounts as of December 31, 2016 and 2015 were assets of $10.3 million and $70.7 million, respectively. See Note 2.

Revenue Recognition

Utility and non-utility revenues, which are derived primarily from the sale, transportation, and storage of natural gas, are recognized upon the delivery of gas commodity or services rendered to customers.

Accrued Unbilled Revenue

For a description of our policy regarding accrued unbilled revenue for both the utility and non-utility revenues, see Note 2. The following table presents changes in key metrics if the estimated percentage of unbilled volume at December 31 was adjusted up or down by 1%:

	2016	
In millions	Up 1%	Down 1%
Unbilled revenue increase (decrease)	$0.6	$(0.6)
Utility margin increase (decrease)[(1)]	—	—
Net income increase (decrease)[(1)]	—	—

[(1)] Includes impact of regulatory mechanisms including decoupling mechanism.

Derivative Instruments and Hedging Activities

Our gas acquisition and hedging policies set forth guidelines for using financial derivative instruments to support prudent risk management strategies. These policies specifically prohibit the use of derivatives for trading or speculative purposes. 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.

Derivative instruments are recorded on our balance sheet at fair value. If certain regulatory conditions are met, then the derivative instrument fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to regulatory accounting (see Note 2, "Industry Regulation"), and no unrealized gain or loss is recognized in current income. The gain or loss from the fair value of a derivative instrument subject to regulatory deferral is included in the recovery from, or refund to, utility customers in future periods (see "Regulatory Accounting", above). If a derivative contract is not subject to regulatory deferral, then the accounting treatment for unrealized gains and losses is recorded in accordance with accounting standards for derivatives and hedging (see Note 2, "Derivatives" and "Industry Regulation") which is either in current income or in accumulated other comprehensive income or loss (AOCI or AOCL). Our derivative contracts outstanding at December 31, 2016, 2015 and 2014 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. Our estimate of fair value may change significantly from period-to-period depending on market conditions and prices. These changes may have an impact on our results of operations, but the impact would largely be mitigated due to the majority of our derivative activities being subject to regulatory deferral treatment. For estimated fair value of unrealized gains and losses, see Note 13.

The following table summarizes the amount of gains and losses realized from commodity price transactions for the last three years:

In millions	2016	2015	2014
Net utility gain (loss) on:			
Commodity			
Swaps	$(26.9)	$(37.7)	$10.5
Options	—	—	—
Total net gain (loss) realized	$(26.9)	$(37.7)	$10.5

Realized gains and losses from commodity hedges shown above were recorded as decreases or increases to cost of gas, respectively, and were included in our annual PGA rates.

Pensions and Postretirement Benefits

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and certain key employees, and other postretirement employee benefit plans covering certain non-union employees. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. Only the qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund the respective retirement benefits. The qualified defined benefit retirement plan for union and non-union employees was closed to new participants several years ago. These plans are not available to employees at any of our subsidiary companies. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and

employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit. The postretirement Welfare Benefit Plan for non-union employees was also closed to new participants several years ago.

Net periodic pension and postretirement benefit costs (retirement benefit costs) and projected benefit obligations (benefit obligations) are determined using a number of key assumptions including discount rates, rate of compensation increases, retirement ages, mortality rates and an expected long-term return on plan assets. See Note 8. These key assumptions have a significant impact on the pension amounts recorded and disclosed. Retirement benefit costs consist of service costs, interest costs, the amortization of actuarial gains, losses and prior service costs, the expected returns on plan assets and, in part, on a market-related valuation of assets, if applicable. The market-related asset valuation reflects differences between expected returns and actual investment returns, which we recognize over a three-year period or less from the year in which they occur, thereby reducing year-to-year volatility in retirement benefit costs.

Accounting standards also require balance sheet recognition of the overfunded or underfunded status of pension and postretirement benefit plans in AOCI or AOCL, net of tax, based on the fair value of plan assets compared to the actuarial value of future benefit obligations. However, the retirement benefit costs related to our qualified defined benefit pension and postretirement benefit plans are generally recovered in utility rates, which are set based on accounting standards for pensions and postretirement benefit expenses. We received approval from the OPUC to recognize the overfunded or underfunded status as a regulatory asset or regulatory liability based on expected rate recovery, rather than including it as AOCI or AOCL under common equity. See "Regulatory Accounting" above and Note 2, "Industry Regulation".

The OPUC allows us to defer a portion of our pension expense above or below the amount set in rates to a regulatory balancing account on the balance sheet. At December 31, 2016, the cumulative amount deferred for future pension cost recovery was $50.9 million. The regulatory balancing account includes the recognition of accrued interest on the account balance at the utility's authorized rate of return, with the equity portion of this interest being deferred until amounts are collected in rates.

A number of factors, as discussed above, are considered in developing pension and postretirement benefit assumptions. For the December 31, 2016 measurement date, we reviewed and updated the following key assumptions:

- our weighted-average discount rate assumptions for pensions was 4.00% for 2016 and 4.21% for 2015, and our weighted-average discount rate assumptions for other postretirement benefits was 3.85% for 2016 and 4.00% for 2015. The rate assumptions were determined for each plan based on a matching of benchmark interest rates to the estimated cash flows, which reflect the timing and amount of future benefit payments. Benchmark interest rates are drawn from the Citigroup Above Median Curve, which consists of high quality

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bonds rated AA- or higher by S&P or Aa3 or higher by Moody's;

- our expected annual rate of future compensation increases, which was revised from a range of 3.25% to 5.0% at December 31, 2015 to a range of 3.25% to 4.5% at December 31, 2016;
- our expected long-term return on qualified defined benefit plan assets, which remained unchanged at a rate of 7.50%;
- our mortality rate assumptions were updated from RP-2014 mortality tables for employees and healthy annuitants with a fully generational projection using scale MP-2014 to corresponding RP-2006 mortality tables using scale MP-2015, which partially offset increases in our projected benefit obligation; and
- other key assumptions, which were based on actual plan experience and actuarial recommendations.

At December 31, 2016, our net pension liability (benefit obligations less market value of plan assets) for the qualified defined benefit plan increased $3.3 million compared to 2015. The increase in our net pension liability is primarily due to the $11.7 million increase in our pension benefit obligation, offset by an increase of $8.4 million in plan assets. The liability for non-qualified plans increased $0.5 million, and the liability for other postretirement benefits decreased $1.7 million in 2016.

We determine the expected long-term rate of return on plan assets by averaging the expected earnings for the target asset portfolio. In developing our expected return, we analyze historical actual performance and long-term return projections, which gives consideration to the current asset mix and our target asset allocation. As of December 31, 2016, the actual annualized returns on plan assets, net of management fees, for the past one-year, five-years, and 10-years were 5.7%, 6.4%, and 3.2%, respectively.

We believe our pension assumptions to be appropriate based on plan design and an assessment of market conditions. However, the following shows the sensitivity of our retirement benefit costs and benefit obligations to changes in certain actuarial assumptions:

Dollars in millions	Change in Assumption	Impact on 2016 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2016
Discount rate:	(0.25)%		
Qualified defined benefit plans		$ 1.2	$ 13.9
Non-qualified plans		—	0.8
Other postretirement benefits		0.1	0.8
Expected long-term return on plan assets:	(0.25)		
Qualified defined benefit plans		0.7	N/A

In July 2012, President Obama signed into law the MAP-21 Act. This legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium

increases, which reduces the level of minimum required contributions in the near-term but generally increases contributions in the long-run as well as increasing the operational costs of running a pension plan. Prior to the MAP-21 Act, we were using interest rates based on a 24-month average yield of investment grade corporate bonds (also referred to as "segment rate") to calculate minimum contribution requirements. MAP-21 Act established a new minimum and maximum corridor for segment rates based on a 25-year average of bond yields, which is to be used in calculating contribution requirements. In August 2014, HATFA was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations. As a result we anticipate lower contributions over the next five years with contributions increasing thereafter.

Income Taxes

Valuation Allowances

We recognize deferred tax assets to the extent that we believe these assets are more likely than not to be realized. In making such a determination, we consider the available positive and negative evidence, including future reversals of existing taxable temporary differences, projected future taxable income, tax-planning strategies, and results of recent operations. The most significant deferred tax asset currently recorded is for alternative minimum tax credits. We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2016. See Note 9.

Uncertain Tax Benefits

The calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in the jurisdictions in which we operate. A tax benefit from a material uncertain tax position will only be recognized when it is more likely than not that the position, or some portion thereof, will be sustained upon examination, including resolution of any related appeals or litigation processes, on the basis of the technical merits. We participate in the Compliance Assurance Process (CAP) with the Internal Revenue Service (IRS). Under the CAP program the Company works with the IRS to identify and resolve material tax matters before the federal income tax return is filed each year. No reserves for uncertain tax benefits were recorded during 2016, 2015, or 2014. See Note 9.

Regulatory Matters

Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from, or refunded to, customers in future rates. At December 31, 2016 and 2015, we had regulatory income tax assets of $43.0 million and $47.4 million, respectively, representing future rate recovery of deferred tax liabilities resulting from differences in utility plant financial statement and tax basis and utility plant removal costs. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates. See Note 2.

Tax Legislation

When significant proposed or enacted changes in income tax rules occur we consider whether there may be a material impact to our financial position, results of operations, cash flows, or whether the changes could

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materially affect existing assumptions used in making estimates of tax related balances.
The final tangible property regulations applicable to all taxpayers were issued on September 13, 2013 and were generally effective for taxable years beginning on or after January 1, 2014. In addition, procedural guidance related to the regulations was issued under which taxpayers may make accounting method changes to comply with the regulations. We have evaluated the regulations and do not anticipate any material impact. However, unit-of-property guidance applicable to natural gas distribution networks has not yet been issued and is expected in 2016. We will further evaluate the effect of these regulations after this guidance is issued, but believe our current method is materially consistent with the new regulations and do not expect these regulations to have a material effect on our financial statements.
The Federal Protecting Americans From Tax Hikes Act of 2015 became law on December 18, 2015 and extended federal bonus depreciation through 2019. See "Financial Conditions—Cash Flows" above.

Environmental Contingencies
We account for environmental liabilities in accordance with accounting standards under the loss contingency guidance when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable. Amounts recorded for environmental contingencies take numerous factors into consideration, including, among other variables, changes in enacted laws, regulatory orders, estimated remediation costs, interest rates, insurance proceeds, participation by other parties, timing of payments, and the input of legal counsel and third-party experts. Accordingly, changes in any of these variables or other factual circumstances could have a material impact on the amounts recorded for our environmental liabilities. For a complete discussion of our environmental policy refer to Note 2. For a discussion of our current environmental sites and liabilities refer to Note 15 and "Contingent Liabilities" above. In addition, for information regarding the regulatory treatment of these costs and our regulatory recovery mechanism, see "Results of Operations—Regulatory Matters—Rate Mechanisms—Environmental Costs" above.

Impairment of Long-Lived Assets
We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for

the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.
We determined there were no long-lived asset impairments in 2016.
In 2015, our Gill Ranch Storage facility within our Gas Storage Segment was reviewed for impairment. This analysis demonstrated sufficient headroom, as the undiscounted cash flows were in excess of the carrying value of the asset and no impairment was indicated. There are no significant changes to the undiscounted cash flow assumptions or other triggering events requiring further assessment for impairment in 2016. The cash flows assume a recovery of storage pricing and the ability to contract with higher value customers. Accordingly, if 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, increased demand and other favorable

market correlations 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 $196.9 million at December 31, 2016. The Company continues to assess these conditions along with other strategic alternatives and their impact on the value of the asset on an ongoing basis.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Supply Risk

We enter into spot, short-term, and long-term natural gas supply contracts, along with associated pipeline transportation contracts, to manage our commodity supply risk. Historically, we have arranged for physical delivery of an adequate supply of gas, including gas in our Mist storage and off-system storage facilities, to meet expected requirements of our core utility customers. Our long-term gas supply contracts are primarily index-based and subject to monthly re-pricing, a strategy that is intended to substantially mitigate credit exposure to our physical gas counterparties. Notional amounts under physical gas contracts were $3.4 million and $7.0 million as of December 31, 2016 and 2015, respectively.

Commodity Price Risk

Natural gas commodity prices are subject to market fluctuations due to unpredictable factors including weather, pipeline transportation congestion, drilling technologies, market speculation, and other factors that affect supply and demand. We manage commodity price risk with financial swaps and physical gas reserves from a long-term investment in working interests in gas leases operated by Jonah Energy. These financial hedge contracts and gas reserves volumes are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. Notional amounts under financial derivative contracts were $123.6 million and $95.5 million as of December 31, 2016 and 2015, respectively. The fair value of financial swaps as of December 31, 2016 was an unrealized gain of $15.4 million with future cash inflows of $13.0 million in 2017 and $2.7 million in 2018 and an outflow of $0.3 million in 2019.

Interest Rate Risk

We are exposed to interest rate risk primarily associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is primarily managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, options and other hedging instruments, to manage and mitigate interest rate exposure. We did not have any interest rate swaps outstanding as of December 31, 2016 or 2015.

Foreign Currency Risk

The costs of certain pipeline and off-system storage services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange rates for our commodity-related demand and reservation charges paid in Canadian dollars. Notional amounts under foreign currency forward contracts were $7.5 million and $9.0 million as of December 31, 2016 and 2015, respectively. If all of the foreign currency forward contracts had been settled on

December 31, 2016, a loss of $0.1 million would have been realized. See Note 13.

Credit Risk

Credit Exposure to Natural Gas Suppliers

Certain gas suppliers have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers at liquid exchange points. We evaluate and monitor suppliers' creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit, or surety bonds, in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We expect these costs would be subject to our PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the daily or monthly market index price tied to liquid exchange points, and we have adequate storage flexibility, we believe it is unlikely a supplier default would have a material adverse effect on our financial condition or results of operations.

Credit Exposure to Financial Derivative Counterparties Based on estimated fair value at December 31, 2016, our overall credit exposure relating to commodity contracts is considered immaterial as it reflects amounts owed to financial derivative counterparties (see table below). However, changes in natural gas prices could result in counterparties owing us money. Therefore, our financial derivatives policy requires counterparties to have at least an investment-grade credit rating at the time the derivative instrument is entered into and specific limits on the contract amount and duration based on each counterparty's credit rating. Due to potential changes in market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor and manage our derivative credit exposure and place counterparties on hold for trading purposes or require cash collateral, letters of credit, or guarantees as circumstances warrant.

The following table summarizes our overall financial swap and option credit exposure, based on estimated fair value, and the corresponding counterparty credit ratings. The table uses credit ratings from S&P and Moody's, reflecting the higher of the S&P or Moody's rating or a middle rating if the entity is split-rated with more than one rating level difference:

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)	
In millions	2016	2015
AA/Aa	$13.7	$(20.0)
A/A	1.7	(3.2)
Total	$15.4	$(23.2)

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In most cases, we also mitigate the credit risk of financial derivatives by having master netting arrangements with our counterparties which provide for making or receiving net cash settlements. Generally, transactions of the same type in the same currency that have settlement on the same day with a single counterparty are netted and a single payment is delivered or received depending on which party
is due funds.

Additionally we have master contracts in place with each of our derivative counterparties that include provisions for posting or calling for collateral. Generally we can obtain cash or marketable securities as collateral with one day's notice. We use various collateral management strategies to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in the significant posting of collateral, if any. We have performed stress tests on the portfolio and concluded the liquidity risk from collateral calls is not material. Our derivative credit exposure is primarily with investment grade counterparties rated AA-/Aa3 or higher. Contracts are diversified across counterparties to reduce credit and liquidity risk.

At December 31, 2016, the Company's financial derivative credit risk on a volumetric basis was geographically concentrated 29% in the United States and 71% in Canada, based on our counterparties' location. At December 31, 2015, the Company's financial derivative credit risk on a volumetric basis was geographically concentrated 41% in the United States and 59% in Canada with our counterparties.

Credit Exposure to Insurance Companies
Our credit exposure to insurance companies for loss or damage claims could be material. We regularly monitor the financial condition of insurance companies who provide general liability insurance policy coverage to NW Natural and its predecessors.

Weather Risk
We have a weather normalization mechanism in Oregon; however, we are exposed to weather risk primarily from our regulated utility business. A large percentage of our utility margin is volume driven, and current rates are based on an assumption of average weather. Our weather normalization mechanism in Oregon is for residential and commercial customers, which is intended to stabilize the recovery of our utility's fixed costs and reduce fluctuations in customers' bills due to colder or warmer than average weather. Customers in Oregon are allowed to opt out of the weather normalization mechanism. As of December 31, 2016, approximately 9% of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 11% of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by a weather normalization mechanism is 20% of all residential and commercial customers. See "Results of Operations—Regulatory Matters—Rate Mechanisms—WARM" above.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) or 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed 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 in the United States of America (GAAP). Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions involving company assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit the preparation of financial statements in accordance with GAAP, and that receipts and expenditures are being made only in accordance with authorizations of management and the Board of Directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of the unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements or fraud. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (2013).

Based on our assessment and those criteria, management has concluded that we maintained effective internal control over financial reporting as of December 31, 2016.

The effectiveness of internal control over financial reporting as of December 31, 2016 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

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

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

February 27, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Northwest Natural Gas Company:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed 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. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
February 27, 2017

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
In thousands, except per share data	2016	2015	2014
Operating revenues	$675,967	$723,791	$754,037
Operating expenses:			
Cost of gas	260,588	327,305	365,490
Operations and maintenance	149,974	157,521	136,982
Environmental remediation	13,298	3,513	—
General taxes	30,538	30,281	29,407
Depreciation and amortization	82,289	80,923	79,193
Total operating expenses	536,687	599,543	611,072
Income from operations	139,280	124,248	142,965
Other income (expense), net	(543)	7,747	1,933
Interest expense, net	39,128	42,539	44,563
Income before income taxes	99,609	89,456	100,335
Income tax expense	40,714	35,753	41,643
Net income	58,895	53,703	58,692
Other comprehensive income:			
Change in employee benefit plan liability, net of taxes of $452 for 2016, ($988) for 2015, and $2,857 for 2014	(744)	1,561	(4,364)
Amortization of non-qualified employee benefit plan liability, net of taxes of ($624) for 2016, ($883) for 2015, and ($438) for 2014	955	1,353	646
Comprehensive income	$59,106	$56,617	$54,974
Average common shares outstanding:			
Basic	27,647	27,347	27,164
Diluted	27,779	27,417	27,223
Earnings per share of common stock:			
Basic	$2.13	$1.96	$2.16
Diluted	2.12	1.96	2.16
Dividends declared per share of common stock	1.87	1.86	1.85

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
In thousands	2016	2015
Assets:		
Current assets:		
Cash and cash equivalents	$3,521	$4,211
Accounts receivable	66,700	68,228
Accrued unbilled revenue	64,946	57,987
Allowance for uncollectible accounts	(1,290)	(870)
Regulatory assets	42,362	69,178
Derivative instruments	17,031	2,719
Inventories	54,129	70,868
Gas reserves	15,926	17,094
Income taxes receivable	—	7,900
Other current assets	24,728	33,460
Total current assets	288,053	330,775
Non-current assets:		
Property, plant, and equipment	3,208,816	3,089,380
Less: Accumulated depreciation	947,916	906,717
Total property, plant, and equipment, net	2,260,900	2,182,663
Gas reserves	100,184	114,552
Regulatory assets	357,530	370,711
Derivative instruments	3,265	27
Other investments	68,376	68,066
Other non-current assets	1,493	2,616
Total non-current assets	2,791,748	2,738,635
Total assets	$3,079,801	$3,069,410

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
In thousands	2016	2015
Liabilities and equity:		
Current liabilities:		
Short-term debt	$53,300	$270,035
Current maturities of long-term debt	39,989	24,973
Accounts payable	85,664	73,219
Taxes accrued	12,149	10,420
Interest accrued	5,966	5,873
Regulatory liabilities	40,290	29,927
Derivative instruments	1,315	22,092
Other current liabilities	35,844	41,148
Total current liabilities	274,517	477,687
Long-term debt	679,334	569,445
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	557,085	530,021
Regulatory liabilities	349,319	339,287
Pension and other postretirement benefit liabilities	225,725	223,105
Derivative instruments	913	3,447
Other non-current liabilities	142,411	145,446
Total deferred credits and other non-current liabilities	1,275,453	1,241,306
Commitments and contingencies (see Note 14 and Note 15)		
Equity:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 28,630 and 27,427 at December 31, 2016 and 2015, respectively	445,187	383,144
Retained earnings	412,261	404,990
Accumulated other comprehensive loss	(6,951)	(7,162)
Total equity	850,497	780,972
Total liabilities and equity	$3,079,801	$3,069,410

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

In thousands	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2013	$364,549	$393,681	$ (6,358)	$751,872
Comprehensive income (loss)	—	58,692	(3,718)	54,974
Dividends on common stock	—	(50,093)	—	(50,093)
Tax expense from employee stock plans	(117)	—	—	(117)
Stock-based compensation	1,646	—	—	1,646
Shares issued pursuant to equity based plans	9,039	—	—	9,039
Balance at December 31, 2014	375,117	402,280	(10,076)	767,321
Comprehensive income	—	53,703	2,914	56,617
Dividends on common stock	—	(50,993)	—	(50,993)
Tax expense from employee stock plans	(118)	—	—	(118)
Stock-based compensation	3,277	—	—	3,277
Shares issued pursuant to equity based plans	4,868	—	—	4,868
Balance at December 31, 2015	383,144	404,990	(7,162)	780,972
Comprehensive income	—	58,895	211	59,106
Dividends on common stock	—	(51,624)	—	(51,624)
Stock-based compensation	2,924	—	—	2,924
Shares issued pursuant to equity based plans	6,358	—	—	6,358
Issuance of common stock, net of issuance costs	52,761	—	—	52,761
Balance at December 31, 2016	$445,187	$412,261	$ (6,951)	$850,497

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
In thousands	2016	2015	2014
Operating activities:			
Net income	$58,895	$53,703	$58,692
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	82,289	80,923	79,193
Regulatory amortization of gas reserves	15,525	17,991	19,335
Deferred tax liabilities, net	32,056	26,972	24,772
Qualified defined benefit pension plan expense	5,274	5,697	4,984
Contributions to qualified defined benefit pension plans	(14,470)	(14,120)	(10,500)
Deferred environmental (expenditures) recoveries, net	(10,469)	(10,568)	88,849
Regulatory disallowance of prior environmental cost deferrals	3,287	15,000	—
Interest income on deferred environmental expenses	—	(5,322)	—
Amortization of environmental remediation	13,298	3,513	—
Other	3,225	3,709	1,853
Changes in assets and liabilities:			
Receivables, net	(7,484)	2,373	14,948
Inventories	16,620	6,964	(17,163)
Income taxes	9,467	(6,541)	1,709
Accounts payable	12,380	(17,175)	(2,020)
Interest accrued	93	(206)	(1,024)
Deferred gas costs	(10,204)	31,918	(23,114)
Other, net	12,365	(10,143)	(24,857)
Cash provided by operating activities	222,147	184,688	215,657
Investing activities:			
Capital expenditures	(139,511)	(118,320)	(120,092)
Utility gas reserves	—	(1,549)	(26,798)
Proceeds from sale of assets	521	410	175
Restricted cash	—	3,000	1,000
Other	2,361	1,161	1,392
Cash used in investing activities	(136,629)	(115,298)	(144,323)
Financing activities:			
Common stock issued, net	60,122	3,875	8,986
Long-term debt issued	150,000	—	—
Long-term debt retired	(25,000)	(60,000)	(80,000)
Change in short-term debt	(216,735)	35,335	46,500
Cash dividend payments on common stock	(51,508)	(49,243)	(50,093)
Other	(3,087)	(4,680)	3,336
Cash used in financing activities	(86,208)	(74,713)	(71,271)
(Decrease) increase in cash and cash equivalents	(690)	(5,323)	63
Cash and cash equivalents, beginning of period	4,211	9,534	9,471
Cash and cash equivalents, end of period	$3,521	$4,211	$9,534
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalization	$36,023	$39,634	$42,602
Income taxes paid, net of refunds	(7,157)	17,306	19,445

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

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.

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

Use of Estimates
The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts in the consolidated financial statements and accompanying notes. Actual amounts could differ from those estimates, and changes would most likely be reported in future periods. Management believes the estimates and assumptions used are reasonable.

Industry Regulation
Our principal businesses are the distribution of natural gas, which is regulated by the OPUC and WUTC, and natural gas storage services, which are regulated by either the FERC or the CPUC, and to a certain extent by the OPUC and

WUTC. Accounting records and practices of our regulated businesses conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with U.S. GAAP. Our businesses regulated by the OPUC, WUTC, and FERC earn a reasonable return on invested capital from approved cost-based rates, while our business regulated by the CPUC earns a return to the extent we are able to charge competitive prices above our costs (i.e. market-based rates).

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or 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.

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At December 31, the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets	
In thousands	2016	2015
Current:		
Unrealized loss on derivatives(1)	$1,315	$22,092
Gas costs	6,830	8,717
Environmental costs(2)	9,989	9,270
Decoupling(3)	13,067	18,775
Other(4)	11,161	10,324
Total current	$42,362	$69,178
Non-current:		
Unrealized loss on derivatives(1)	$913	$3,447
Pension balancing(5)	50,863	43,748
Income taxes	38,670	43,049
Pension and other postretirement benefit liabilities	183,035	184,223
Environmental costs(2)	63,970	76,584
Gas costs	89	1,949
Decoupling(3)	5,860	6,349
Other(4)	14,130	11,362
Total non-current	$357,530	$370,711

	Regulatory Liabilities	
In thousands	2016	2015
Current:		
Gas costs	$8,054	$14,157
Unrealized gain on derivatives(1)	16,624	2,659
Other(4)	15,612	13,111
Total current	$40,290	$29,927
Non-current:		
Gas costs	$1,021	$8,869
Unrealized gain on derivatives(1)	3,265	27
Accrued asset removal costs(6)	341,107	327,047
Other(4)	3,926	3,344
Total non-current	$349,319	$339,287

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

(2) 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 15.

(3) This deferral represents the margin adjustment resulting from differences between actual and expected volumes.

(4) 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.

(5) 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.

(6) Estimated costs of removal on certain regulated properties are collected through rates. See "Accounting Policies—Plant, Property, and Accrued Asset Removal Costs" below.

The amortization period for our regulatory assets and liabilities ranges from less than one year to an indeterminable period. Our regulatory deferrals for gas costs payable are generally amortized over 12 months beginning each November 1 following the gas contract year during which the deferred gas costs are recorded. Similarly, most of our other regulatory deferred accounts are amortized over 12 months. However, certain regulatory account balances, such as income taxes, environmental costs, pension liabilities, and accrued asset removal costs, are large and tend to be amortized over longer periods once we have agreed upon an amortization period with the respective regulatory agency.

We believe all costs incurred and deferred at December 31, 2016 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.

Environmental Regulatory Accounting

On January 27, 2016 the OPUC issued an Order regarding SRRM implementation (2016 Order) in which the OPUC: (1) disallowed the recovery of $2.8 million of interest earned on the previously disallowed environmental expenditure amounts; (2) clarified the state allocation of 96.68% of environmental remediation costs for all environmental sites to Oregon; and (3) confirmed our treatment of $13.8 million of expenses put into the SRRM amortization account was correct and in compliance with prior OPUC orders. As a result of the 2016 Order, we recognized a $3.3 million non-cash charge in the first quarter, of which $2.8 million is reflected in other income and expense, net and $0.5 million is included in operations and maintenance expense. See Note 15 regarding our SRRM.

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.

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Recently Adopted Accounting Pronouncements

STOCK BASED COMPENSATION. On March 30, 2016, the FASB issued ASU 2016-09, "Compensation - Stock Compensation: Improvements to Employee Share-Based Payment Accounting." The ASU changes how companies account for certain aspects of share-based payment awards to employees, including the accounting for income taxes, forfeitures, accounting treatments for statutory tax withholding policy elections, as well as classification in the statement of cash flows. Currently, tax benefits and detriments from stock compensation are recorded directly to equity and under the new guidance, they are charged to income tax expense. The new guidance also allows for an entity to account for forfeitures as they occur. Additionally, the new guidance allows for companies to withhold an amount up to the applicable maximum statutory tax rate, without triggering liability classification for the award. The amendments in this standard are effective for us beginning January 1, 2017. Early adoption is permitted in any interim or annual period. NW Natural early adopted ASU 2016-09 in the fourth quarter ended December 31, 2016. The adoption of this ASU did not materially affect our financial statements and disclosures.

GOING CONCERN. On August 27, 2014, the FASB issued ASU 2014-15, "Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern." In connection with preparing financial statements for each annual and interim reporting period, the ASU requires an entity's management to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. Disclosures are required when management identifies conditions or events that raise substantial doubt. The new requirements were effective for us for the annual period ended December 31, 2016. This ASU did not materially affect our financial statements and disclosures, but required management to assess the company's ability to continue as a going concern for each reporting period.

FAIR VALUE MEASUREMENT. On May 1, 2015, the FASB issued ASU 2015-07, "Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent)." The ASU removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and also removes certain disclosure requirements. The new requirements were effective for us beginning January 1, 2016 and were applied retrospectively to all periods presented, in this 2016 Form 10-K. This ASU did not materially affect our financial statements and disclosures, but changed certain presentation and disclosures of the fair value of certain plan assets in Note 8, for all periods presented.

INTANGIBLES - GOODWILL AND OTHER INTERNAL-USE SOFTWARE. On April 15, 2015 the FASB issued ASU 2015-05, "Customer’s Accounting for Fees Paid in a Cloud Computing Arrangement." The ASU provides customers guidance on how to determine whether a cloud computing arrangement includes a software license. The new requirements were effective for us beginning January 1,

2016 and did not materially affect our financial statements and disclosures.

DEBT ISSUANCE COSTS. On April 7, 2015, the FASB issued ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs," which requires the presentation of debt issuance costs in the balance sheet as a direct deduction from the associated debt liability. The new requirements were effective for us beginning January 1, 2016. The new guidance has been applied on a retrospective basis and is reflected in our consolidated balance sheets and Note 7. Accordingly, debt issuance costs totaling $7.4 million and $7.3 million, as of December 31, 2016 and 2015, respectively, are now presented as a direct offset to the associated long-term debt instrument.

Recently Issued Accounting Pronouncements

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 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. Early

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adoption is permitted, and we are currently assessing the effect of this standard on our financial statements and disclosures.

REVENUE RECOGNITION. On May 28, 2014, the FASB issued ASU 2014-09 "Revenue From Contracts with Customers." 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, how Contributions in Aid of Construction will be accounted for, 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. The FASB also permitted early adoption of the standard, but not before the original effective date of January 1, 2017. We plan to adopt the new standard effective January 1, 2018.

In March 2016, the FASB issued a final amendment to clarify the implementation guidance for principal versus agent considerations. This update will require us to report franchise taxes in which we are the principal on a gross basis, whereas we are currently reporting franchise taxes on a net basis.

In April 2016, the FASB issued a final amendment to clarify the guidance related to identifying performance obligations and the accounting for licenses of intellectual property. We do not expect significant impacts based on this update.

In May 2016, the FASB issued an amendment regarding narrow scope improvements and practical expedients. We are currently assessing the impact of this update.

In December 2016, the FASB issued a final amendment regarding technical corrections and improvements. We do not expect significant impacts based on this update.

Accounting Policies

Plant, Property, and Accrued Asset Removal Costs
Plant and property are stated at cost, including capitalized labor, materials and overhead. In accordance with regulatory accounting standards, the cost of acquiring and constructing long-lived plant and property generally includes an

allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the regulatory financing cost incurred when debt and equity funds are used for construction (see “AFUDC” below). When constructed assets are subject to market-based rates rather than cost-based rates, the financing costs incurred during construction are included in capitalized interest in accordance with U.S. GAAP, not as regulatory financing costs under AFUDC.

In accordance with long-standing regulatory treatment, our depreciation rates consist of three components: one based on the average service life of the asset, a second based on the estimated salvage value of the asset, and a third based on the asset's estimated cost of removal. We collect, through rates, the estimated cost of removal on certain regulated properties through depreciation expense, with a corresponding offset to accumulated depreciation. These removal costs are non-legal obligations as defined by regulatory accounting guidance. Therefore, we have included these costs as non-current regulatory liabilities rather than as accumulated depreciation on our consolidated balance sheets. In the rate setting process, the liability for removal costs is treated as a reduction to the net rate base on which the regulated utility has the opportunity to earn its allowed rate of return.

The costs of utility plant retired or otherwise disposed of are removed from utility plant and charged to accumulated depreciation for recovery or refund through future rates. Gains from the sale of regulated assets are generally deferred and refunded to customers. For non-utility assets, we record a gain or loss upon the disposal of the property, and the gain or loss is recorded in operating income in the consolidated statements of comprehensive income.

Our provision for depreciation of utility property, plant, and equipment is recorded under the group method on a straight-line basis with rates computed in accordance with depreciation studies approved by regulatory authorities. The weighted-average depreciation rate for utility assets in service was approximately 2.8% for 2016, 2015, and 2014, reflecting the approximate weighted-average economic life of the property. This includes 2016 weighted-average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.2% for gas storage facilities, 4.2% for general plant, and 2.8% for intangible and other fixed assets.

AFUDC. Certain additions to utility plant include AFUDC, which represents the net cost of debt and equity funds used during construction. AFUDC is calculated using actual interest rates for debt and authorized rates for ROE, if applicable. If short-term debt balances are less than the total balance of construction work in progress, then a composite AFUDC rate is used to represent interest on all debt funds, shown as a reduction to interest charges, and on ROE funds, shown as other income. While cash is not immediately recognized from recording AFUDC, it is realized in future years through rate recovery resulting from the higher utility cost of service. Our composite AFUDC rate was 0.7% in 2016, 0.4% in 2015, and 0.3% in 2014.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

When such factors are present, we assess the recoverability by determining whether the carrying value of the asset will be recovered through expected future cash flows. An asset is determined to be impaired when the carrying value of the asset exceeds the expected undiscounted future cash flows from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss for the difference between the carrying value and the fair value of the long-lived assets. Fair value is estimated using appropriate valuation methodologies, which may include an estimate of discounted cash flows.

We determined there were no long-lived asset impairments in 2016.

In 2015, our Gill Ranch Storage facility within our Gas Storage Segment was reviewed for impairment. This analysis demonstrated sufficient headroom, as the undiscounted cash flows were in excess of the carrying value of the asset and no impairment was indicated. There are no significant changes to the undiscounted cash flow assumptions or other triggering events requiring further assessment for impairment in 2016. The cash flows assume continued operation of the Gill Ranch storage facility with a recovery of storage pricing and the ability to contract with higher value customers. Accordingly, if 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, increased demand and other favorable market correlations 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 $196.9 million at December 31, 2016. The Company continues to assess these conditions along with other strategic alternatives and their impact on the value of the asset on an ongoing basis.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with original maturity dates of three months or less. At December 31, 2016 and 2015, outstanding checks of approximately $2.9 million and $2.5 million, respectively, were included in accounts payable.

Revenue Recognition and Accrued Unbilled Revenue

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized upon delivery of the gas commodity or service to customers. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of deliveries from meter

reading dates to month end (accrued unbilled revenue). Accrued unbilled revenue is dependent upon a number of factors that require management's judgment, including total gas receipts and deliveries, customer use by billing cycle, and weather factors. Accrued unbilled revenue is reversed the following month when actual billings occur. Our accrued unbilled revenue at December 31, 2016 and 2015 was $64.9 million and $58.0 million, respectively.

Non-utility revenues are derived primarily from the gas storage segment. At our Mist underground storage facility, revenues are primarily firm service revenues in the form of fixed monthly reservation charges. At our Gill Ranch facility, firm storage services resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. In addition, we also have asset management service revenue from an independent energy marketing company that optimizes commodity, storage, and pipeline capacity release transactions. Under this agreement, guaranteed asset management revenue is recognized using a straight-line, pro-rata methodology over the term of each contract. Revenues earned above the guaranteed amount are recognized as they are earned.

Revenue Taxes

Revenue-based taxes are primarily franchise taxes, which are collected from customers and remitted to taxing authorities. Revenue taxes are included in operating revenues in the statement of comprehensive income. Revenue taxes were $17.1 million, $18.0 million, and $18.8 million for 2016, 2015, and 2014, respectively.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consist primarily of amounts due for natural gas sales and transportation services to utility customers, plus amounts due for gas storage services. We establish an allowance for uncollectible accounts (allowance) for trade receivables, including accrued unbilled revenue, based on the aging of receivables, collection experience of past due account balances including payment plans, and historical trends of write-offs as a percent of revenues. A specific allowance is established and recorded for large individual customer receivables when amounts are identified as unlikely to be partially or fully recovered. Inactive accounts are written-off against the allowance after they are 120 days past due or when deemed uncollectible. Differences between our estimated allowance and actual write-offs will occur based on a number of factors, including changes in economic conditions, customer creditworthiness, and natural gas prices. The allowance for uncollectible accounts is adjusted quarterly, as necessary, based on information currently available.

Inventories

Utility gas inventories, which consist of natural gas in storage for the utility, are stated at the lower of average cost or net realizable value. The regulatory treatment of utility gas inventories provides for cost recovery in customer rates. Utility gas inventories injected into storage are priced in inventory based on actual purchase costs. Utility gas inventories withdrawn from storage are charged to cost of gas during the current period at the weighted-average inventory cost.

Gas storage inventories, which primarily represent inventories at our Gill Ranch storage facility, mainly consist of natural gas received as fuel-in-kind from storage customers. Gas storage inventories are valued at the lower of average cost or net realizable value. Cushion gas is not included in our inventory balances, is recorded at original cost, and classified as a long-term plant asset.

Materials and supplies inventories consist of both utility and non-utility inventories and are stated at the lower of average cost or net realizable value.

Our utility and gas storage inventories totaled $42.7 million and $59.3 million at December 31, 2016 and 2015, respectively. At December 31, 2016 and 2015, our materials and supplies inventories totaled $11.4 million and $11.6 million, respectively.

Gas Reserves
Gas reserves are payments to acquire and produce natural gas reserves. Gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. The current portion is calculated based on expected gas deliveries within the next fiscal year. We recognize regulatory amortization of this asset on a volumetric basis calculated using the estimated gas reserves and the estimated therms extracted and sold each month. The amortization of gas reserves is recorded to cost of gas along with gas production revenues and production costs. See Note 11.

Derivatives
Derivatives are measured at fair value and recognized as either assets or liabilities on the balance sheet. Changes in the fair value of the derivatives are recognized currently in earnings unless specific regulatory or hedge accounting criteria are met. Accounting for derivatives and hedges provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivative contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these approved contracts are deferred as regulatory assets or liabilities pursuant to regulatory accounting principles. Our financial derivatives generally qualify for deferral under regulatory accounting. Our index-priced physical derivative contracts also qualify for regulatory deferral accounting treatment.

Derivative contracts entered into for utility requirements after the annual PGA rate has been set and maturing during the PGA year are subject to the PGA incentive sharing mechanism. In Oregon we participate in a PGA sharing mechanism under which we are required to select either an 80% or 90% deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20% or 10% of gas cost differences compared to PGA prices, respectively. For the PGA years in Oregon beginning November 1, 2016, 2015, and 2014 we selected the 90%, 80%, and 90% deferral of gas cost differences, respectively.

In Washington, 100% of the differences between the PGA prices and actual gas costs are deferred. See Note 13.

Our financial derivatives policy sets forth the guidelines for using selected derivative products to support prudent risk management strategies within designated parameters. Our objective for using derivatives is to decrease the volatility of gas prices, earnings, and cash flows without speculative risk. The use of derivatives is permitted only after the risk exposures have been identified, are determined not to exceed acceptable tolerance levels, and are determined necessary to support normal business activities. We do not enter into derivative instruments for trading purposes.

Fair Value

In accordance with fair value accounting, we use the following fair value hierarchy for determining inputs for our debt, pension plan assets, and our derivative fair value measurements:

- Level 1: Valuation is based on quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based on quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and
- Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of assumptions market participants would use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; (g) credit spreads; and (h) other relevant economic measures. The Company considers liquid points for its natural gas hedging to be those points for which there are regularly published prices in a nationally recognized publication or where the instruments are traded on an exchange.

Income Taxes

We account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the enactment date period unless a regulatory Order specifies deferral of the effect of the change in tax rates over a longer period of time.

Deferred income tax assets and liabilities are also recognized for temporary differences where the deferred income tax benefits or expenses have previously been flowed through in the ratemaking process of the regulated utility. Regulatory tax assets and liabilities are recorded on these deferred tax assets and liabilities to the extent the Company believes they will be recoverable from or refunded to customers in future rates. At December 31, 2016 and 2015, regulatory income tax assets of $43.0 million and $47.4 million, respectively, were recorded, a portion of which is recorded in current assets. These regulatory income tax assets primarily represent future rate recovery of deferred tax liabilities, resulting from differences in utility plant financial statement and tax bases and utility plant removal costs, which were previously flowed through for rate making purposes and to take into account the additional future taxes, which will be generated by that recovery. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates.

Deferred investment tax credits on utility plant additions, which reduce income taxes payable, are deferred for financial statement purposes and amortized over the life of the related plant.

The Company recognizes interest and penalties related to unrecognized tax benefits, if any, within income tax expense and accrued interest and penalties within the related tax liability line in the consolidated balance sheets. No accrued interest or penalties for uncertain tax benefits have been recorded. See Note 9.

Environmental Contingencies

Loss contingencies are recorded as liabilities when it is probable a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results.

With respect to environmental liabilities and related costs, we develop estimates based on a review of information available from numerous sources, including completed studies and site specific negotiations. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, it is our policy to accrue at the low end of the range. Accordingly, due to 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 potential loss and the fact that the high end of the range cannot be reasonably estimated. See Note 15.

Subsequent Events

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. We do not have any subsequent events to report.

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:

In thousands, except per share data	2016	2015	2014
Net income	$58,895	$53,703	$58,692
Average common shares outstanding - basic	27,647	27,347	27,164
Additional shares for stock-based compensation plans (See Note 6)	132	70	59
Average common shares outstanding - diluted	27,779	27,417	27,223
Earnings per share of common stock - basic	$2.13	$1.96	$2.16
Earnings per share of common stock - diluted	$2.12	$1.96	$2.16
Additional information:			
Antidilutive shares	5	12	18

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. No individual customer accounts for over 10% of our operating revenues.

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale, and delivery of natural gas and related services to customers in Oregon and southwest Washington. As a regulated utility, we are responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into our service territory, and re-selling the gas to customers subject to rates, terms, and conditions approved by the OPUC or WUTC. Gas distribution also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers’ end-use facilities for a fee, which is approved by the OPUC or WUTC. Approximately 89% of our customers are located in Oregon and 11% in Washington. On an annual basis, residential and commercial customers typically account for around 60% of our utility’s total volumes delivered and 90% of our utility’s margin. Industrial customers largely account

for the remaining volumes and utility margin. A small amount of utility margin is also derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism, and other service fees.

Industrial sectors we serve include: pulp, paper, and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation.

Gas Storage
Our gas storage segment includes natural gas storage services provided to customers primarily from two underground natural gas storage facilities, our Gill Ranch gas storage facility, and the non-utility portion of our Mist gas storage facility. In addition to earning revenue from customer storage contracts, we also use an independent energy marketing company to provide asset management services for utility and non-utility capacity, the results of which are included in this business segment.

Mist Gas Storage Facility
Earnings from non-utility assets at our Mist facility in Oregon are primarily related to firm storage capacity revenues. Earnings for the Mist facility also include revenue, net of amounts shared with utility customers, from management of utility assets at Mist and upstream pipeline capacity when not needed to serve utility customers. We retain 80% of the pre-tax income from these services when the costs of the capacity have not been included in utility rates, or 33% of the pre-tax income when the costs have been included in utility rates. The remaining 20% and 67%, respectively, are recorded to a deferred regulatory account for crediting back to utility customers.

Gill Ranch Gas Storage Facility
Gill Ranch has a joint project agreement with Pacific Gas and Electric Company (PG&E) to own and operate the Gill Ranch underground natural gas storage facility near

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Fresno, California. Gill Ranch has a 75% undivided ownership interest in the facility and is also the operator of the facility, which offers storage services to the California market at market-based rates, subject to CPUC regulation including, but not limited to, service terms and conditions and tariff regulations. Although this is a jointly owned property, each owner is independently responsible for financing its share of the Gill Ranch natural gas storage facility. Revenues are primarily related to firm storage capacity as well as asset management revenues.

Other
We have non-utility investments and other business activities, which are aggregated and reported as other. Other primarily consists of an equity method investment in

TWH, which was formed to build and operate an interstate gas transmission pipeline in Oregon (TWP) and other pipeline assets in NNG Financial. For more information on TWP, see Note 12. Other also includes some corporate operating and non-operating revenues and expenses that cannot be allocated to utility operations.

NNG Financial's assets primarily consist of an active, wholly-owned subsidiary which owns a 10% interest in an 18-mile interstate natural gas pipeline. NNG Financial's total assets were $0.5 million and $0.7 million at December 31, 2016 and 2015, respectively.

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

In thousands	Utility	Gas Storage	Other	Total
2016				
Operating revenues	$650,477	$25,266	$224	$675,967
Depreciation and amortization	76,289	6,000	—	82,289
Income (loss) from operations	130,570	9,136	(426)	139,280
Net income	54,567	4,303	25	58,895
Capital expenditures	138,074	1,437	—	139,511
Total assets at December 31, 2016	2,806,627	256,333	16,841	3,079,801
2015				
Operating revenues	$702,210	$21,356	$225	$723,791
Depreciation and amortization	74,410	6,513	—	80,923
Income from operations	119,215	5,032	1	124,248
Net income	53,391	174	138	53,703
Capital expenditures	115,272	3,048	—	118,320
Total assets at December 31, 2015	2,791,623	261,750	16,037	3,069,410
2014				
Operating revenues	$731,578	$22,235	$224	$754,037
Depreciation and amortization	72,660	6,533	—	79,193
Income from operations	138,711	3,987	267	142,965
Net income (loss)	58,587	(364)	469	58,692

Capital expenditures	117,322	2,770	—	120,092
Total assets at December 31, 2014	2,766,493	273,712	16,121	3,056,326

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.

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The following table presents additional segment information concerning utility margin:

In thousands	2016	2015	2014
Utility margin calculation:			
Utility operating revenues [1]	$650,477	$702,210	$731,578
Less: Utility cost of gas	260,588	327,305	365,490
Environmental remediation expense	13,298	3,513	—
Utility margin	$376,591	$371,392	$366,088

(1) 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. Collections under this mechanism began in November 2015.

5. COMMON STOCK

Common Stock

As of December 31, 2016 and 2015, we had 100 million shares of common stock authorized. As of December 31, 2016, we had reserved 60,661 shares for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 224,438 shares under our Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). At the Company's election, shares sold through our DRPP may be purchased in the open market or through original issuance of shares reserved for issuance under the DRPP. In July 2015 we moved our DRPP to open market purchases.

The Restated Stock Option Plan (SOP) was terminated with respect to new grants in 2012; however, options granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. There were 180,163 options outstanding at December 31, 2016, which were granted prior to termination of the plan.

During November 2016, the Company completed an equity issuance consisting of an offering of 880,000 shares of its common stock along with a 30-day option for the underwriters to purchase an additional 132,000 shares. The offering closed on November 16, 2016 and resulted in a total issuance of 1,012,000 shares as both the initial offering and the underwriter option were fully executed. All shares were issued on November 16, 2016 at an offering price of $54.63 per share and resulted in total net proceeds to the Company of $52.8 million.

Stock Repurchase Program

We have a share repurchase program under which we may purchase our common shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2017 to repurchase up to an aggregate of the greater of 2.8 million shares or $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2016. Since the plan’s inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding:

In thousands	Shares
Balance, December 31, 2013	27,075
Sales to employees under ESPP	24
Stock-based compensation	83
Sales to shareholders under DRPP	102

Balance, December 31, 2014	27,284
Sales to employees under ESPP	19
Stock-based compensation	78
Sales to shareholders under DRPP	46
Balance, December 31, 2015	27,427
Sales to employees under ESPP	18
Stock-based compensation	173
Equity Issuance	1,012
Balance, December 31, 2016	28,630

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6. 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 ESPP, and a Restated SOP.

Long Term Incentive Plan

The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. Under the LTIP, shares of common stock are authorized for equity incentive grants in the form of stock, restricted stock, restricted stock units, stock options, or performance shares. An aggregate of 850,000 shares were authorized for issuance as of December 31, 2016. Shares awarded under the LTIP may be purchased on the open market or issued as original shares.

Of the 850,000 shares of common stock authorized for LTIP awards at December 31, 2016, there were 173,279 shares available for issuance under any type of award and 250,000 shares available for option grants. This assumes market, performance, and service based grants currently outstanding are awarded at the target level. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2016 or 2015. The LTIP stock awards are compensatory awards for which compensation expense is based on the fair value of stock awards, with expense being recognized over the performance and vesting period of the outstanding awards. Forfeitures are recognized as they occur.

Performance Shares

Since the LTIP's inception in 2001, performance shares, which incorporate market, performance, and service-based factors, have been granted annually with three-year performance periods. The following table summarizes performance share expense information:

Dollars in thousands	Shares[1]	Expense During Award Year[2]	Total Expense for Award
Estimated award:			
2014-2016 grant[3]	27,887	$ 168	$ 1,418
Actual award:			
2013-2015 grant	8,914	312	1,240
2012-2014 grant	8,621	582	1,821

(1) 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.

(2) Amount represents the expense recognized in the third year of the vesting period noted above.

(3) This represents the estimated number of shares to be awarded as of December 31, 2016 as certain performance share measures had been achieved. Amounts are subject to change with final payout amounts authorized by the Board of Directors in February 2017.

The aggregate number of performance shares granted and outstanding at the target and maximum levels were as follows:

Dollars in thousands	Performance Share Awards Outstanding		2016	Cumulative Expense
Performance Period	Target	Maximum	Expense	December 31, 2016
2014-16	39,725	79,450	$ 168	$ 1,418
2015-17	36,200	72,400	662	1,515
2016-18	27,950	55,900	478	478
Total	103,875	207,750	$ 1,308	

Performance share awards are based on EPS and Return on Invested Capital (ROIC) factors, a total shareholder return (TSR factor) relative to a peer group of gas distribution companies over the three-year performance period, and on performance results achieved relative to specific core and non-core strategies (strategic factor). Compensation expense is recognized in accordance with accounting standards for stock-based compensation and calculated based on performance levels achieved and an estimated fair value using the Monte-Carlo method. The weighted-average grant date fair value of unvested shares at December 31, 2016 and 2015 was $50.83 and $49.09 per share, respectively. The weighted-average grant date fair value of shares vested during the year was $51.80 per share and for shares granted during the year was $50.15 per share. As of December 31, 2016, there was $2.2 million of unrecognized compensation expense related to the unvested portion of performance awards expected to be recognized through 2018.

Restricted Stock Units

In 2012, the Company began granting RSUs under the LTIP instead of stock options under the Restated SOP. Generally, the RSUs awarded are forfeitable and include a performance-based threshold as well as a vesting period of 4 years from the grant date. Upon vesting, the RSU holder is issued 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 an RSU is equal to the closing market price of the Company's common stock on the grant date. During 2016, total RSU expense was $1.5 million compared to $1.3 million in 2015 and $0.9 million in 2014. As of December 31, 2016, there was $2.9 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2022.

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Information regarding the RSU activity is summarized as follows:

	Number of RSUs	Weighted - Average Price Per RSU
Nonvested, December 31, 2013	44,567	$ 46.27
Granted	38,765	42.19
Vested	(12,060)	46.52
Forfeited	(478)	45.47
Nonvested, December 31, 2014	70,794	44.00
Granted	37,264	46.29
Vested	(19,003)	44.81
Forfeited	(468)	44.99
Nonvested, December 31, 2015	88,587	44.78
Granted	40,271	54.36
Vested	(29,488)	45.56
Forfeited	(9,397)	44.59
Nonvested, December 31, 2016	89,973	48.85

Restated Stock Option Plan

The Restated SOP was terminated for new option grants in 2012; however, options granted before the plan terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP, however, no option grants have been awarded since 2012.

Options under the Restated SOP were granted to officers and key employees designated by a committee of our Board of Directors. All options were granted at an option price equal to the closing market price on the date of grant and may be exercised for a period of up to 10 years and seven days from the date of grant. Option holders may exchange shares they have owned for at least six months, valued at the current market price, to purchase shares at the option price.

Information regarding the Restated SOP activity is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value (In millions)
Balance outstanding, December 31, 2013	492,150	$ 42.89	$ 0.6
Exercised	(69,662)	39.82	0.5
Forfeited	(6,400)	43.59	n/a
Balance outstanding, December 31, 2014	416,088	43.40	2.7
Exercised	(62,900)	39.96	0.5
Forfeited	(500)	45.74	n/a
Balance outstanding, December 31, 2015	352,688	44.00	2.3
Exercised	(172,525)	43.61	2.0
Forfeited	—	n/a	n/a
Balance outstanding and exercisable, December 31, 2016	180,163	44.38	2.8

During 2016, cash of $7.5 million was received for stock options exercised and $0.4 million related tax expense was recognized. All stock options were vested as of December 31, 2015. During 2015, the total fair value of options that vested was $0.2 million. The weighted average remaining life of options exercisable and outstanding at December 31, 2016 was 3.06 years.

Employee Stock Purchase Plan
The ESPP allows employees to purchase common stock at 85% of the closing price on the trading day immediately preceding the initial offering date, which is set annually. Each eligible employee may purchase up to $21,248 worth of stock through payroll deductions over a 12-month period, with shares issued at the end of the 12-month subscription period.

Stock-Based Compensation Expense
Stock-based compensation expense is recognized as operations and maintenance expense or is capitalized as part of construction overhead. The following table summarizes the financial statement impact of stock-based compensation under our LTIP, Restated SOP and ESPP:

In thousands	2016	2015	2014
Operations and maintenance expense, for stock-based compensation	$2,370	$2,673	$2,309
Income tax benefit	(924)	(1,012)	(861)
Net stock-based compensation effect on net income	$1,446	$1,661	$1,448
Amounts capitalized for stock-based compensation	$554	$661	$597

7. DEBT

Short-Term Debt
Our primary source of short-term funds is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans to meet seasonal working capital requirements, short-term debt is used temporarily to fund capital requirements. Commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by one or more committed credit facilities.

At December 31, 2016, total short-term debt outstanding was $53 million, which was comprised entirely of commercial paper. At December 31, 2015, total short-term debt outstanding was $270 million, which included $220 million of commercial paper and a $50 million credit facility. The weighted average interest rate at December 31, 2016 and 2015 was 0.8% and 0.6%, respectively.

In the fourth quarter of 2015, we entered into a short-term credit facility loan totaling $50 million, as a short-term bridge through our peak heating season, which was repaid on February 4, 2016.

The carrying cost of our commercial paper approximates fair value using Level 2 inputs, due to the short-term nature of the notes. See Note 2 for a description of the fair value hierarchy. At December 31, 2016, our commercial paper had a maximum remaining maturity of 11 days and an average remaining maturity of 6 days.

We have a $300 million credit agreement, with a feature that allows us to request increases in the total commitment amount up to a maximum amount of $450 million. The maturity of the agreement is December 20, 2019. We have a letter of credit of $100 million. Any principal and unpaid interest owed on borrowings under the agreement is due and payable on or before the expiration date. There were no outstanding balances under the agreement and no letters of credit issued or outstanding at December 31, 2016 and 2015.

The credit agreement requires that we 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 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 facility. However, interest rates on any loans outstanding under the credit facility are tied to debt ratings, which would increase or decrease the cost of any loans under the credit facility when ratings are changed.

The credit agreement also 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 December 31, 2016 and 2015.

Long-Term Debt

The issuance of FMBs, which includes our medium-term notes, under the Mortgage and Deed of Trust (Mortgage) is limited by eligible property, adjusted net earnings and other provisions of the Mortgage. The Mortgage constitutes a first mortgage lien on substantially all of our utility property.

Maturities and Outstanding Long-Term Debt

Retirement of long-term debt for each of the 12-month periods through December 31, 2021 and thereafter are as follows:

In thousands	
Year	
2017	$40,000
2018	97,000
2019	30,000
2020	75,000
2021	60,000
Thereafter	424,700

The following table presents our debt outstanding as of December 31:

In thousands	2016	2015
First Mortgage Bonds		
5.15 % Series B due 2016	$—	$25,000
7.00 % Series B due 2017	40,000	40,000
1.545 % Series B due 2018	75,000	—
6.60 % Series B due 2018	22,000	22,000
8.31 % Series B due 2019	10,000	10,000

7.63 % Series B due 2019	20,000	20,000
5.37 % Series B due 2020	75,000	75,000
9.05 % Series A due 2021	10,000	10,000
3.176 % Series B due 2021	50,000	50,000
3.542% Series B due 2023	50,000	50,000
5.62 % Series B due 2023	40,000	40,000
7.72 % Series B due 2025	20,000	20,000
6.52 % Series B due 2025	10,000	10,000
7.05 % Series B due 2026	20,000	20,000
3.211 % Series B due 2026	35,000	—
7.00 % Series B due 2027	20,000	20,000
6.65 % Series B due 2027	19,700	19,700
6.65 % Series B due 2028	10,000	10,000
7.74 % Series B due 2030	20,000	20,000
7.85 % Series B due 2030	10,000	10,000
5.82 % Series B due 2032	30,000	30,000
5.66 % Series B due 2033	40,000	40,000
5.25 % Series B due 2035	10,000	10,000
4.00 % due 2042	50,000	50,000
4.136 % Series B due 2046	40,000	—
	726,700	601,700
Less: Current maturities	40,000	25,000
Total long-term debt	$686,700	$576,700

First Mortgage Bonds

NW Natural issued $150 million of FMBs on December 5, 2016 consisting of $75 million with a coupon rate of 1.545%% and maturity date in 2018, $35 million with a coupon rate of 3.211%% and maturity date in 2026, and $40 million with a coupon rate of 4.136%% and maturity date in 2046.

Retirements of Long-Term Debt

NW Natural redeemed $25 million of FMBs with a coupon rate of 5.15% in December 2016.

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.

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:

	December 31,	
In thousands	2016	2015
Gross long-term debt	$726,700	$601,700
Unamortized debt issuance costs	(7,377)	(7,282)
Carrying amount	$719,323	$594,418
Estimated fair value	$793,339	$667,168

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8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and other key employees, and other postretirement employee benefit plans. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. The qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund retirement benefits. Effective January 1, 2007 and 2010, the qualified defined benefit pension plans and postretirement benefits for non-union employees and union employees, respectively, were closed to new participants. These plans were not available to employees of our non-utility subsidiaries. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit. Effective December 31, 2012, the qualified defined benefit pension plans for non-union and union employees were merged into a single plan.

The following table provides a reconciliation of the changes in benefit obligations and fair value of plan assets, as applicable, for the pension and other postretirement benefit plans, excluding the Retirement K Savings Plan, and a summary of the funded status and amounts recognized in the consolidated balance sheets as of December 31:

	Postretirement Benefit Plans			
	Pension Benefits		Other Benefits	
In thousands	2016	2015	2016	2015
Reconciliation of change in benefit obligation:				
Obligation at January 1	$445,628	$487,278	$31,049	$32,072
Service cost	7,083	8,267	391	527
Interest cost	18,399	18,360	1,175	1,179
Plan amendments[1]	—	—	—	(3,435)
Net actuarial (gain) loss	7,688	(32,354)	(1,488)	2,724
Benefits paid	(20,959)	(35,923)	(1,732)	(2,018)
Obligation at December 31	$457,839	$445,628	$29,395	$31,049
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$249,338	$279,164	$—	$—
Actual return on plan assets	12,593	(9,599)	—	—
Employer contributions	16,742	15,696	1,732	2,018
Benefits paid	(20,959)	(35,923)	(1,732)	(2,018)
Fair value of plan assets at December 31	$257,714	$249,338	$—	$—
Funded status at December 31	$(200,125)	$(196,290)	$(29,395)	$(31,049)

(1) In 2015, we amended our Retiree Medical Plan for NBU post-age 65 retirees hired before January 1, 2007, to establish a health retirement account (HRA). The HRA plan permits participants to obtain reimbursement of health care expenses on a nontaxable basis, and the amendment was effective April 1, 2016.

Our qualified defined benefit pension plan has an aggregate benefit obligation of $423.5 million and $411.8 million at December 31, 2016 and 2015, respectively, and fair values of plan assets of $257.7 million and $249.3 million, respectively.

The following table presents amounts realized through regulatory assets or in other comprehensive loss (income) for the years ended December 31:

	Regulatory Assets						Other Comprehensive Loss (Income)		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2016	2015	2014	2016	2015	2014	2016	2015	2014
Net actuarial loss (gain)	$14,005	$419	$83,027	$(1,488)	$2,724	$3,454	$(1,196)	$(2,549)	$7,221
Settlement Loss	—	—	—	—	—	—	193	—	—
Amortization of:									
Prior service cost	(230)	(230)	(230)	468	(197)	(197)	—	—	7
Actuarial loss	(13,238)	(16,372)	(9,823)	(705)	(554)	(221)	1,386	(2,236)	(1,091)
Total	$537	$(16,183)	$72,974	$(1,725)	$1,973	$3,036	$383	$(4,785)	$6,137

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The following table presents amounts recognized in regulatory assets and accumulated other comprehensive loss (AOCL) at December 31:

	Regulatory Assets				AOCL	
	Pension Benefits		Other Postretirement Benefits		Pension Benefits	
In thousands	2016	2015	2016	2015	2016	2015
Prior service cost (credit)	$176	$406	$(2,675)	$(3,143)	$1	$1
Net actuarial loss	177,660	176,894	7,874	10,067	11,434	11,870
Total	$177,836	$177,300	$5,199	$6,924	$11,435	$11,871

The following table presents amounts recognized in AOCL and the changes in AOCL related to our non-qualified employee benefit plans:

	Year Ended December 31,	
In thousands	2016	2015
Beginning balance	$(7,162)	$(10,076)
Amounts reclassified to AOCL	(1,196)	2,549
Amounts reclassified from AOCL:		
Amortization of actuarial losses	1,386	—
Loss from plan settlement	193	2,236
Total reclassifications before tax	383	4,785
Tax (benefit) expense	(172)	(1,871)
Total reclassifications for the period	211	2,914
Ending balance	$(6,951)	$(7,162)

In 2017, an estimated $13.8 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $14.1 million of actuarial losses, and $0.3 million of prior service credits. A total of $0.9 million will be amortized from AOCL to earnings related to actuarial losses in 2017.

Our assumed discount rate for the pension plan and other postretirement benefit plans was determined independently based on the Citigroup Above Median Curve (discount rate curve), which uses high quality corporate bonds rated AA- or higher by S&P or Aa3 or higher by Moody's. The discount rate curve was applied to match the estimated cash flows in each of our plans to reflect the timing and amount of expected future benefit payments for these plans.

Our assumed expected long-term rate of return on plan assets for the qualified pension plan was developed using a weighted average of the expected returns for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plan's assets are invested and the target asset allocation for plan assets.

Our investment strategy and policies for qualified pension plan assets held in the retirement trust fund were approved by our retirement committee, which is composed of senior management with the assistance of an outside investment consultant. The policies set forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity, portfolio risk and return expectations. All investments are expected to satisfy the prudent investments rule under the Employee Retirement Income Security Act of 1974. The approved asset classes may include cash and short-term investments, fixed income, common stock and convertible securities, absolute and real

return strategies, real estate, and investments in NW Natural securities. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Investment re-balancing takes place periodically as needed, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target ranges. The retirement trust fund is not currently invested in NW Natural securities.

The following table presents the pension plan asset target allocation at December 31, 2016:

Asset Category	Target Allocation	
U.S. large cap equity	18.0	%
U.S. small/mid cap equity	10.0	
Non-U.S. equity	18.0	
Emerging markets equity	5.0	
Long government/credit	20.0	
High yield bonds	5.0	
Emerging market debt	5.0	
Real estate funds	7.0	
Absolute return strategy	12.0	

Our non-qualified supplemental defined benefit plan obligations were $34.3 million and $33.8 million at December 31, 2016 and 2015, respectively. These plans are not subject to regulatory deferral, and the changes in actuarial gains and losses, prior service costs and transition assets, or obligations are recognized in AOCL, net of tax until they are amortized as a component of net periodic benefit cost. These are unfunded, non-qualified plans with no plan assets; however, we indirectly fund a significant portion of our obligations with company- and trust-owned life insurance and other assets.

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Our other postretirement benefit plans are unfunded plans but are subject to regulatory deferral. The actuarial gains and losses, prior service costs and transition assets or obligations for these plans are recognized as a regulatory asset.

Net periodic benefit costs consist of service costs, interest costs, the amortization of actuarial gains and losses and

the expected returns on plan assets, which are based in part on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns with the differences recognized over a three-year or less period from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

The following table provides the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2016	2015	2014	2016	2015	2014
Service cost	$7,083	$8,267	$7,213	$391	$527	$483
Interest cost	18,399	18,360	18,198	1,175	1,179	1,252
Expected return on plan assets	(20,054)	(20,676)	(19,496)	—	—	—
Amortization of prior service costs	231	231	223	(468)	197	197
Amortization of net actuarial loss	14,624	18,609	10,914	705	554	221
Settlement expense	193	—	—	—	—	—
Net periodic benefit cost	20,476	24,791	17,052	1,803	2,457	2,153
Amount allocated to construction	(5,746)	(6,834)	(4,625)	(600)	(808)	(702)
Amount deferred to regulatory balancing account[1]	(6,252)	(8,241)	(4,578)	—	—	—
Net amount charged to expense	$8,478	$9,716	$7,849	$1,203	$1,649	$1,451

(1) 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.

Net periodic benefit costs are reduced by amounts capitalized to utility plant based on approximately 25% to 35% payroll overhead charge. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions. Net periodic pension cost less amounts charged to capital accounts and regulatory balancing accounts are expenses recognized in earnings.

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2016	2015	2014	2016	2015	2014
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	4.17%	3.82%	4.71%	4.00%	3.74%	4.45%
Rate of increase in compensation	3.25-4.5%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a

Expected long-term rate of return	7.50 %	7.50 %	7.50 %	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	4.00 %	4.21 %	3.85 %	3.85%	4.00%	3.74%
Rate of increase in compensation	3.25-4.5%	3.25-4.5%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50 %	7.50 %	7.50 %	n/a	n/a	n/a

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2016 was 7.00% for both pre- and post-65 populations. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.75% by 2025.

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Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable from the Company. A one percentage point change in assumed health care cost trend rates would have the following effects:

In thousands	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	$ 51	$ (45)
Effect on the accumulated postretirement benefit obligation	644	(577)

We review mortality assumptions annually and will update for material changes as necessary. In 2016, our mortality rate assumptions were updated from RP-2014 mortality tables for employees and healthy annuitants with a fully generational projection using scale MP-2014 to corresponding RP-2006 mortality tables using scale MP-2015, which partially offset increases of our projected benefit obligation.

The following table provides information regarding employer contributions and benefit payments for the qualified pension plan, non-qualified pension plans and other postretirement benefit plans for the years ended December 31, and estimated future contributions and payments:

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2015	$ 15,696	$ 2,018
2016	16,742	1,732
2017 (estimated)	21,380	1,876
Benefit Payments:		
2014	19,932	1,871
2015	35,923	2,018
2016	20,959	1,732
Estimated Future Benefit Payments:		
2017	22,171	1,876
2018	23,088	1,893
2019	23,953	1,977
2020	24,782	2,020
2021	25,690	2,054
2022-2026	136,699	10,189

Employer Contributions to Company-Sponsored Defined Benefit Pension Plans

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. The Pension Protection Act of 2006 (the Act) established funding requirements for defined benefit plans. The Act establishes a 100% funding target over seven years for plan years beginning after December 31, 2008. In 2012 the Moving Ahead for Progress in the 21st Century Act (MAP-21) legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium increases, which reduces the level of minimum required contributions in the near-term but generally increases

contributions in the long-run and increases the operational costs of running a pension plan. In 2014, the Highway and Transportation Funding Act (HATFA) was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations.

Our qualified defined benefit pension plan is currently underfunded by $165.8 million at December 31, 2016. Including the impacts of MAP-21 and HATFA, we made cash contributions totaling $14.5 million to our qualified defined benefit pension plan for 2016. During 2017, we expect to make contributions of approximately $19.4 million to this plan.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit plans presented above, prior to 2014 we contributed to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan). The plan's employer identification number is 94-6076144. Effective December 22, 2013, we withdrew from the plan, which was a noncash transaction. Vested participants will receive all benefits accrued through the date of withdrawal. As the plan was underfunded at the time of withdrawal, we were assessed a withdrawal liability of $8.3 million, plus interest, which requires NW Natural to pay $0.6 million each year to the plan for 20 years beginning in July 2014. The cost of the withdrawal liability was deferred to a regulatory account on the balance sheet.

We made payments of $0.6 million for 2016, and as of December 31, 2016 the liability balance was $7.5 million. For 2015 and 2014, contributions to the plan were $0.6 million and $0.4 million, respectively, which was approximately 4% to 5% of the total contributions to the plan by all employer participants in those years.

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 $4.6 million, $3.7 million, and $3.4 million for 2016, 2015, and 2014, respectively. The Retirement K Savings Plan includes an Employee Stock Ownership Plan.

Deferred Compensation Plans

The supplemental deferred compensation plans for eligible officers and senior managers are non-qualified plans. These plans are designed to enhance the retirement savings of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly.

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Fair Value

Below is a description of the valuation methodologies used for assets measured at fair value. In cases where the pension plan is invested through a collective trust fund or mutual fund, our custodian uses the fund's market value. The custodian also provides the market values for investments directly owned.

U.S. LARGE CAP EQUITY and U.S. SMALL/MID CAP EQUITY. These are level 1 and non-published net asset value (NAV) assets. The level 1 assets consist of directly held stocks and mutual funds with a readily determinable fair value, including a published NAV. The non-published NAV assets consist of commingled trusts where NAV is not published but the investment can be readily disposed of at NAV or market value. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded. Mutual funds and commingled trusts are valued at NAV and the unit price, respectively. This asset class includes investments primarily in U.S. common stocks.

NON-U.S. EQUITY. These are level 1 and non-published NAV assets. The level 1 assets consist of directly held stocks, and the non-published NAV assets consist of commingled trusts where the NAV/unit price is not published but the investment can be readily disposed of at the NAV/unit price. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded, and the commingled trusts are valued at unit price. This asset class includes investments primarily in foreign equity common stocks.

EMERGING MARKETS EQUITY. These are non-published NAV assets consisting of an open-end mutual fund where the NAV price is not published but the investment can be readily disposed of at the NAV, and a commingled trust where the investment can be readily disposed of at unit price. This asset class includes investments primarily in common stocks in emerging markets.

FIXED INCOME. These are non-published NAV assets consisting of a commingled trust, valued at unit price, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes investments primarily in investment grade debt and fixed income securities.

LONG GOVERNMENT/CREDIT. These are level 2 assets and non-published NAV assets. The level 2 assets consist of directly held fixed-income securities, with readily determinable fair values, whose values are determined by closing prices if available and by matrix prices for illiquid securities. The non-published NAV assets include commingled trusts, valued at unit price, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes long duration fixed income investments primarily in U.S. treasuries, U.S. government agencies, municipal securities, mortgage-backed securities, asset-backed securities, as well as U.S. and international investment-grade corporate bonds.

HIGH YIELD BONDS. These are non-published NAV assets, consisting of a limited partnership and a commingled trust where the valuation is not published but the investment can

be readily disposed of at market value, valued at NAV or unit price, respectively. This asset class includes investments primarily in high yield bonds.

EMERGING MARKET DEBT. This is a non-published NAV asset consisting of a commingled trust with a readily determinable fair value, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes investments primarily in emerging market debt.

REAL ESTATE. These are level 1 and non-published NAV assets. The level 1 asset is a mutual fund with a readily determinable fair value, including a published NAV. The non-published NAV asset is a commingled trust with a readily determinable fair value, where unit price is not published, but the investment can be readily disposed of at the unit price. This asset class includes investments primarily in real estate investment trust (REIT) equity securities globally.

ABSOLUTE RETURN STRATEGY. This is a non-published NAV asset consisting of a hedge fund of funds where the valuation is not published. This hedge fund of funds is winding down. Based on recent dispositions, we believe the remaining investment is fairly valued. The hedge fund of funds is valued at the weighted average value of investments in various hedge funds, which in turn are valued at the closing price of the underlying securities. This asset class primarily includes investments in common stocks and fixed income securities.

CASH AND CASH EQUIVALENTS. These are level 1 and non-published NAV assets. The level 1 assets consist of cash in U.S. dollars, which can be readily disposed of at face value. The non-published NAV assets represent mutual funds without published NAV's but the investment can be readily disposed of at the NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date. This asset class includes cash and money market mutual funds.

The preceding valuation methods may produce a fair value calculation that is not indicative of net realizable value or reflective of future fair values. Although we believe these valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain investments could result in a different fair value measurement at the reporting date.

Investment securities are exposed to various financial risks including interest rate, market and credit risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the values of our investment securities will occur in the near term and such changes could materially affect our investment account balances and the amounts reported as plan assets available for benefit payments.

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The following table presents the fair value of plan assets, including outstanding receivables and liabilities, of the retirement trust fund:

In thousands	December 31, 2016				
Investments	Level 1	Level 2	Level 3	Non-Published NAV[1]	Total
U.S. large cap equity	$49,841	$—	$—	$ 5,655	$55,496
U.S. small/mid cap equity	18,629	—	—	10,232	28,861
Non-U.S. equity	22,404	—	—	25,346	47,750
Emerging markets equity	—	—	—	13,457	13,457
Fixed income	—	—	—	6,719	6,719
Long government/credit	—	34,955	—	17,960	52,915
High yield bonds	—	—	—	14,072	14,072
Emerging market debt	—	—	—	8,504	8,504
Real estate	17,857	—	—	882	18,739
Absolute return strategy	—	—	—	3,111	3,111
Cash and cash equivalents	9	—	—	2,482	2,491
Total investments	$108,740	$34,955	$—	$ 108,420	$252,115

	December 31, 2015				
Investments	Level 1	Level 2	Level 3	Non-Published NAV[1]	Total
U.S. large cap equity	$44,528	$—	$—	$ —	$44,528
U.S. small/mid cap equity	23,495	—	—	—	23,495
Non-U.S. equity	20,725	—	—	22,823	43,548
Emerging markets equity	—	—	—	11,120	11,120
Fixed income	—	—	—	—	—
Long government/credit	—	35,656	—	12,800	48,456
High yield bonds	—	—	—	12,298	12,298
Emerging market debt	7,746	—	—	—	7,746
Real estate	17,261	—	—	—	17,261
Absolute return strategy	—	—	—	36,758	36,758
Cash and cash equivalents	49	—	—	4,067	4,116
Total investments	$113,804	$35,656	$—	$ 99,866	$249,326

	December 31, 2016	2015
Receivables:		
Accrued interest and dividend income	$451	$486
Due from broker for securities sold	5,170	88
Total receivables	$5,621	$574
Liabilities:		
Due to broker for securities purchased	$22	$562
Total investment in retirement trust	$257,714	$249,338

[1] The fair value for these investments is determined using Net Asset Value per share (NAV) as of December 31, 2016, as a practical expedient, and therefore they are not classified within the fair value hierarchy. These investments primarily consist of institutional investment products, for which the NAV is generally not publicly

available.

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9. INCOME TAX

The following table provides a reconciliation between income taxes calculated at the statutory federal tax rate and the provision for income taxes reflected in the consolidated statements of comprehensive income for December 31:

Dollars in thousands	2016	2015	2014
Income taxes at federal statutory rate	$34,863	$31,310	$35,117
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,582	4,195	4,666
Amortization of investment tax credits	(41)	(118)	(201)
Differences required to be flowed-through by regulatory commissions	2,357	2,357	2,357
Gains on company and trust-owned life insurance	(594)	(766)	(689)
Other, net	(453)	(1,225)	393
Total provision for income taxes	$40,714	$35,753	$41,643
Effective tax rate	40.9%	40.0%	41.5%

The effective income tax rate for 2016 compared to 2015 increased primarily as a result of lower depletion deductions from gas reserves activity in 2016. The effective income tax rate decrease from 2015 compared to 2014 was primarily due to the benefit from the realization of deferred depletion benefits from 2013 and 2014.

The provision for current and deferred income taxes consists of the following at December 31:

In thousands	2016	2015	2014
Current			
Federal	$7,402	$10,558	$14,823
State	2,042	61	24
	9,444	10,619	14,847
Deferred			
Federal	26,219	18,729	18,635
State	5,051	6,405	8,161
	31,270	25,134	26,796
Total provision for income taxes	$40,714	$35,753	$41,643

The following table summarizes the total provision (benefit) for income taxes for the utility and non-utility business segments for December 31:

In thousands	2016	2015	2014
Utility:			
Current	$10,300	$15,890	$24,317
Deferred	28,749	20,834	19,518
Deferred investment tax credits	(41)	(118)	(201)
	39,008	36,606	43,634
Non-utility business segments:			
Current	(856)	(5,271)	(9,470)
Deferred	2,562	4,418	7,479
	1,706	(853)	(1,991)
Total provision for income taxes	$40,714	$35,753	$41,643

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts at December 31:

In thousands	2016	2015
Deferred tax liabilities:		
Plant and property	$428,642	$408,342
Regulatory income tax assets	43,048	47,427
Regulatory liabilities	48,291	46,400
Non-regulated deferred tax liabilities	51,446	49,683
Total	$571,427	$551,852
Deferred tax assets:		
Pension and postretirement obligations	$4,493	$4,666
Alternative minimum tax credit carryforward	9,853	16,699
Loss and credit carryforwards	—	514
Total	14,346	21,879
Deferred income tax liabilities, net	557,081	529,973
Deferred investment tax credits	4	48
Deferred income taxes and investment tax credits	$557,085	$530,021

Management assesses the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize the existing deferred tax assets. Based upon this assessment, we have determined we are more likely than not to realize all deferred tax assets recorded as of December 31, 2016.

The Company estimates it has alternative minimum tax (AMT) credits of $9.9 million. The AMT credits do not expire. All other tax attributes have been fully utilized in the current year.

As a result of certain realization requirements prescribed in the accounting guidance for income taxes, the tax benefit of statutory depletion is recognized no earlier than the year in which the depletion is deductible on the Company’s federal income tax return. Income tax expense decreased by $0.9 million in 2015 as a result of realizing deferred depletion benefit from 2013 and 2014. This benefit is included in Other in the statutory rate reconciliation table.

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Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the anticipated settlement outcome of material uncertain tax positions taken in a prior year, or planned to be taken in the current year. Until such positions are sustained, we would not recognize the uncertain tax benefits resulting from such positions. No reserves for uncertain tax positions existed as of December 31, 2016, 2015, or 2014.

The Company's federal income tax returns for tax years 2012 and earlier are closed by statute. The IRS Compliance Assurance Process (CAP) examination of the 2013 and 2014 tax years were completed in the first and fourth quarters of 2015, respectively. There were no material changes to these returns as filed. The 2015 and 2016 tax years are currently under IRS CAP examination. The Company's 2017 CAP application has been accepted by the IRS. Under the CAP program, the Company works with the IRS to identify and resolve material tax matters before the tax return is filed each year. As of December 31, 2016, income tax years 2013 through 2016 remain open for state examination.

10. PROPERTY, PLANT, AND EQUIPMENT

The following table sets forth the major classifications of our property, plant, and equipment and accumulated depreciation at December 31:

In thousands	2016	2015
Utility plant in service	$2,843,243	$2,745,485
Utility construction work in progress	62,264	39,288
Less: Accumulated depreciation	903,096	867,377
Utility plant, net	2,002,411	1,917,396
Non-utility plant in service	299,378	296,839
Non-utility construction work in progress	3,931	7,768
Less: Accumulated depreciation	44,820	39,340
Non-utility plant, net	258,489	265,267
Total property, plant, and equipment	$2,260,900	$2,182,663
Capital expenditures in accrued liabilities	$9,547	$8,985

The weighted average depreciation rate for utility assets was 2.8% for utility assets during 2016, 2015, and 2014. The weighted average depreciation rate for non-utility assets was 2.0% in 2016 and 2.2% in 2015 and 2014.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $341.1 million and $327.0 million at December 31, 2016 and 2015, respectively. These accrued asset removal costs are reflected on the balance sheet as regulatory liabilities. See Note 2. During 2016 and 2015 we did not acquire any equipment under capital leases.

11. GAS RESERVES

We have invested $188 million through our gas reserves program in the Jonah Field located in Wyoming as of December 31, 2016. 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.

We entered into our original agreements with Encana in 2011 under which we hold working interests in certain sections of the Jonah Field. Gas produced in these sections is sold at prevailing market prices, and revenues from such sales, net of associated operating and production costs and amortization, are credited to the utility's cost of gas. The cost of gas, including a carrying cost for the rate base investment, 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.

In March 2014, we amended the original gas reserves agreement in order to facilitate Encana's proposed sale of its interest in the Jonah field to Jonah Energy. Under the amendment, we ended the drilling program with Encana, but increased our working interests in our assigned sections of the Jonah field. We also retained the right to invest in new wells with Jonah Energy. Under the amended agreement we still 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 elected to participate in some of the additional wells drilled in 2014, but did not have the opportunity to participate in additional wells in 2015 and 2016. However, we may have the opportunity to participate in more wells in the future.

Gas produced from the additional wells is 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.

Gas reserves acted to hedge the cost of gas
for approximately 8%, 11% and 10% of our utility's gas supplies for the years ended December 31, 2016, 2015, and 2014 respectively.

The following table outlines our net gas reserves investment at December 31:

In thousands	2016	2015
Gas reserves, current	$15,926	$17,094
Gas reserves, non-current	171,610	170,453
Less: Accumulated amortization	71,426	55,901
Total gas reserves[(1)]	116,110	131,646
Less: Deferred taxes on gas reserves	28,119	27,203
Net investment in gas reserves	$87,991	$104,443

(1) Our net investment in additional wells included in total gas reserves was $6.7 million and $8.0 million at December 31, 2016 and 2015, respectively.

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

12. INVESTMENTS

Investments include financial investments in life insurance policies, which are accounted for at cash surrender value, net of policy loans, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity method. The following table summarizes our other investments at December 31:

In thousands	2016	2015
Investments in life insurance policies	$52,719	$52,308
Investments in gas pipeline	13,767	13,866
Other	1,890	1,892
Total other investments	$68,376	$68,066

Investment in Life Insurance Policies

We have invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term employee and director benefit plan liabilities. The amount in the above table is reported at cash surrender value, net of policy loans.

Investments in Gas Pipeline

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.

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 December 31, 2016 and 2015.

Impairment Analysis

Our investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment at each reporting period and following updates to our corporate planning assumptions. If it is determined a loss in value is other than temporary, a charge is recognized for the difference between the investment's carrying value and its estimated fair value. Fair value is based on quoted market prices when available or on the present value of expected future cash flows. Differing assumptions could affect the timing and amount of a charge recorded in any period.

In 2011, TWP withdrew its original application with the FERC for a proposed natural gas pipeline in Oregon and informed FERC that it intended to re-file an application to reflect changes in the project scope aligning the project with the region's current and future gas infrastructure needs. TWP continues working with customers in the Pacific Northwest to further understand their gas transportation needs and determine the commercial support for a revised pipeline proposal. A new FERC certificate application is expected to be filed to reflect a revised scope based on these regional needs.

Our equity investment was not impaired at December 31, 2016 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2016. However, if we learn that the project is not viable or will not go forward, then we could be required to recognize a maximum charge of up to approximately $13.4 million based on the current amount of our equity investment, net of cash and working capital at TWP. We will continue to monitor and update our impairment analysis as required.

13. 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:

	At December 31,	
In thousands	2016	2015
Natural gas (in therms):		
Financial	477,430	346,875
Physical	535,450	404,645
Foreign exchange	$7,497	$9,025

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:

In thousands	December 31, 2016 Natural gas commodity	December 31, 2016 Foreign exchange	December 31, 2015 Natural gas commodity	December 31, 2015 Foreign exchange
Benefit (expense) to cost of gas	$22,746	$ (130)	$(16,469)	$ (419)
Operating revenues	995	—	178	—
Amounts deferred to regulatory accounts on balance sheet	(23,394)	130	16,351	419
Total gain in pre-tax earnings	$347	$ —	$60	$ —

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 $26.9 million and $37.7 million for the years ended December 31, 2016 and 2015, 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 December 31, 2016 or 2015. 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 2016 or 2015. 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

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additional collateral in the event of a material adverse change.

Based upon current commodity financial swap and option contracts outstanding, which reflect unrealized gains of $15.4 million at December 31, 2016, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Specul-ative
With Adequate Assurance Calls	$ —	$ —	$ —	$ —	$ 16,086
Without Adequate Assurance Calls	—	—	—	—	13,784

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 $18.8 million and a liability of $0.7 million as of December 31, 2016. As of December 31, 2015, our derivative position would have resulted in an asset of $2.7 million and a liability of $25.5 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. We utilize master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. In certain cases we require guarantees or letters of credit from counterparties to meet our minimum credit requirement standards.

Our financial derivatives policy requires counterparties to have a certain investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty's credit rating. We do not speculate with derivatives; instead, we use derivatives to hedge our exposure above risk tolerance limits. Any increase in market risk created by the use of derivatives should be offset by the exposures they modify.

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes

consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions and market news. We use a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. The results of the model are used to establish earnings-at-risk trading limits. Our credit risk for all outstanding financial derivatives at December 31, 2016 extends to March 2019.

We could become materially exposed to credit risk with one or more of our counterparties if natural gas prices experience a significant increase. If a counterparty were to become insolvent or fail to perform on its obligations, we could suffer a material loss; however, we would expect such a loss to be eligible for regulatory deferral and rate recovery, subject to a prudence review. All of our existing counterparties currently have investment-grade credit ratings.

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 December 31, 2016. As of December 31, 2016 and 2015, the net fair value was an asset of $18.1 million and a liability of $22.8 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 years ended December 31, 2016 and 2015. See Note 2.

14. COMMITMENTS AND CONTINGENCIES

Leases
We lease land, buildings and equipment under agreements that expire in various years, including a 99-year land lease that extends through 2108. Rental expense under operating leases was $6.2 million, $5.5 million, and $5.9 million for the years ended December 31, 2016, 2015, and 2014, respectively. The following table reflects the future minimum lease payments due under non-cancelable leases at December 31, 2016. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities and computer equipment.

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In thousands	Operating leases	Capital leases	Minimum lease payments
2017	$ 5,476	$ 156	$ 5,632
2018	5,385	3	5,388
2019	5,340	—	5,340
2020	2,835	—	2,835
2021	930	—	930
Thereafter	28,895	—	28,895
Total	$ 48,861	$ 159	$ 49,020

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

We have signed agreements providing for the reservation of firm pipeline capacity under which we are required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies. In addition, we have entered into long-term sale agreements to release firm pipeline capacity. We also enter into short-term and long-term gas purchase agreements.

The aggregate amounts of these agreements were as follows at December 31, 2016:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2017	$ 78,587	$ 81,206	$ 4,487
2018	—	79,741	3,739
2019	—	77,125	—
2020	—	72,021	—
2021	—	45,971	—
Thereafter	—	296,592	—
Total	78,587	652,656	8,226
Less: Amount representing interest	220	101,576	94
Total at present value	$ 78,367	$ 551,080	$ 8,132

Our total payments for fixed charges under capacity purchase agreements were $85.0 million for 2016, $85.2 million for 2015, and $94.3 million for 2014. Included in the amounts were reductions for capacity release sales of $4.5 million for 2016, $4.4 million for 2015, and $4.8 million for 2014. In addition, per-unit charges are required to be paid based on the actual quantities shipped under the agreements. In certain take-or-pay purchase commitments, annual deficiencies may be offset by prepayments subject to recovery over a longer term if future purchases exceed the minimum annual requirements.

Environmental Matters

Refer to Note 15 for a discussion of environmental commitments and contingencies.

15. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties (PRPs). When amounts are prudently expended related to site remediation, 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 above.

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

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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 the claim as well as the potential liability.

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 at December 31:

	Current Liabilities		Non-Current Liabilities	
In thousands	2016	2015	2016	2015
Portland Harbor site:				
Gasco/Siltronic Sediments	$869	$2,229	$43,972	$42,641
Other Portland Harbor	1,970	1,972	4,148	5,073
Gasco/Siltronic Upland site	10,657	11,550	49,183	52,454
Central Service Center site	73	25	—	—
Front Street site	906	1,155	7,786	7,748
Oregon Steel Mills	—	—	179	179
Total	$14,475	$16,931	$105,268	$108,095

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 a PRP to the Superfund site and had previously joined with some of the other PRPs (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/Feasibility Study (RI/FS), which we submitted to the EPA in 2012. In August 2015, the EPA issued its own Draft Feasibility Study (Draft FS) for comment. The EPA Draft FS provided a new range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of present value costs estimated by the EPA for various remedial alternatives for the entire Portland Harbor, as provided by the EPA's Draft FS, was $791 million to $2.45 billion. The range provided in the EPA's Draft FS was based on cost alternatives the EPA estimates to have an accuracy between -30% and +50% of actual costs, depending on the scope of work.

In June 2016, the EPA issued their Final Feasibility Study (Final FS) and proposed remediation plan (Proposed Plan) for the Portland Harbor Superfund site. The Proposed Plan presented the EPA's preferred clean-up alternative, which estimated the present value cost at approximately $746 million with an accuracy between -30% and +50% of actual costs. Along with several members of the LWG, we filed a dispute with the EPA over concerns that the EPA's Final FS contained factual and technical errors and was insufficient to support remedy selection. We also submitted comments to the Proposed Plan identifying technical errors and suggesting corrections to the Plan.

After reviewing all public comments, the EPA released its Record of Decision in January 2017, 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 cost at approximately $1.05 billion with an accuracy between -30% and +50% of actual costs.

While the Portland Harbor ROD provides a higher range of costs than the LWG's submission in 2012, our potential liability is still 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.

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. NW Natural incurs costs related to its membership in the LWG. NW Natural also incurs costs related to NRD from these sites. The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased 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, as defined in the complaint by the Yakama Nation. 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. Generally, NRD claims may arise only after a remedy for clean-up has been settled. 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. This liability is not included in the range of costs provided in the Final FS or 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 are working with ODEQ on monitoring the effectiveness of the system and at this time it is unclear what, if any, additional actions ODEQ may require subsequent to the initial testing of the system or as part of the final remedy for the uplands portion of the Gasco site. We have estimated the cost associated with the ongoing operation of the system and have recognized a liability which is at the low end of the range of potential cost. We cannot estimate the high end of the range 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.

Beginning November 1, 2013, capital asset costs of $19.0 million for the Gasco water treatment station were placed into rates with OPUC approval. The OPUC deemed these costs prudent. Beginning November 1, 2014, the OPUC approved the application of $2.5 million from insurance proceeds plus interest to reduce the total amount of Gasco capital costs to be recovered through rate base. A portion of these proceeds was noncash in 2014.

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. 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 $1.1 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.

REGULATORY ACTIVITIES. In February 2015, the OPUC issued an Order addressing outstanding issues related to the SRRM (2015 Order), which required us to forego the collection of $15 million out of approximately $95 million in total environmental remediation expenses and associated carrying costs we had deferred through 2012 based on the OPUC's determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for other factors the OPUC deemed relevant. As a result, we recognized a $15 million non-cash charge in operations and maintenance expense in the first quarter of 2015. Also, as a result of the 2015 Order, we recognized $5.3 million pre-tax of interest income related to the equity earnings on our deferred environmental expenses.

In addition, the OPUC issued a subsequent Order regarding the SRRM implementation in January 2016 (2016 Order) in which the OPUC: (1) disallowed the recovery of $2.8 million of interest earned on the previously disallowed environmental expenditure amounts; (2) clarified the state allocation of 96.68% of environmental remediation costs for all environmental sites to Oregon; and (3) confirmed our treatment of $13.8 million of expenses put into the SRRM amortization account was correct and in compliance with prior OPUC orders. As a result of the 2016 Order, we recognized a $3.3 million non-cash charge in the first quarter of 2016, of which $2.8 million is reflected in other income and expense, net and $0.5 million is included in operations and maintenance expense.

COLLECTIONS FROM OREGON CUSTOMERS. The SRRM provides us with the ability to recover past deferred and future prudently incurred environmental remediation costs allocable to Oregon, subject to an earnings test. The SRRM created three classes 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. We included $9.0 million of deferred remediation expense approved by the OPUC for collection during the 2016-2017 PGA year.

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 our deferred regulatory asset balance through operating expense.

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 OPUC Order, one-third of the Oregon allocated proceeds were applied to costs deferred through 2012, and the remaining two-thirds will be applied to costs over the next 20 years. Annually, the Order provided for the application of $5 million of insurance proceeds plus interest against deferred remediation expense deemed prudent in the same annual period; annual amounts not utilized are carried forward to apply against future prudently incurred costs. 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 December 31, 2016, 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 as of December 31:

In thousands	2016	2015
Deferred costs and interest (1)	$53,039	$79,505
Accrued site liabilities (2)	119,443	125,026
Insurance proceeds and interest	(98,523)	(118,677)
Total regulatory asset deferral(1)	$73,959	$85,854
Current regulatory assets(3)	9,989	9,270
Long-term regulatory assets(3)	63,970	76,584

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

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

(3) 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.

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ENVIRONMENTAL EARNINGS TEST. The 2015 Order directed us to implement an annual environmental earnings test for our prudently incurred remediation expense. Prudently incurred Oregon allocated annual remediation expense and interest in excess of the $5 million tariff rider and $5 million insurance proceeds application plus interest on the insurance proceeds are recoverable through the SRRM, to the extent the utility earns at or below our authorized Return On Equity (ROE). 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 (plus interest from insurance proceeds) 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 I, Item 3, “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.

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NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Quarter ended			
In thousands, except share data	March 31	June 30	September 30	December 31
2016				
Operating revenues	$255,529	$99,183	$87,727	$233,528
Net income (loss)	36,641	2,019	(8,040)	28,275
Basic earnings (loss) per share[1]	1.33	0.07	(0.29)	1.01
Diluted earnings (loss) per share[1]	1.33	0.07	(0.29)	1.00
2015				
Operating revenues	$261,665	$138,280	$93,128	$230,718
Net income (loss)	28,486	2,197	(6,685)	29,705
Basic earnings (loss) per share[1]	1.04	0.08	(0.24)	1.08
Diluted earnings (loss) per share[1]	1.04	0.08	(0.24)	1.08

(1) Quarterly earnings (loss) per share are based upon the average number of common shares outstanding during each quarter. Variations in earnings between quarterly periods are due primarily to the seasonal nature of our business.

NORTHWEST NATURAL GAS COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions		Deductions	
In thousands (year ended December 31)	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net write-offs	Balance at end of period
2016					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 870	$ 1,246	$ —	$ 826	$ 1,290
2015					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 969	$ 760	$ —	$ 859	$ 870
2014					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 1,656	$ 599	$ —	$ 1,286	$ 969

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities

and Exchange Commission (SEC) rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

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

There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2016 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 9(a).

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The "Information Concerning Nominees and Continuing Directors", "Corporate Governance", and "Section 16(a) Beneficial Ownership Reporting Compliance" contained in our definitive Proxy Statement for the May 25, 2017 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2016	Positions held during last five years
Gregg S. Kantor[1]	59	Advisor to Board of Directors (2016); Chief Executive Officer (2009-2016); President (2009-2015); President and Chief Operating Officer (2007-2008); Executive Vice President (2006-2007); Senior Vice President, Public and Regulatory Affairs (2003-2006).
David H. Anderson	55	Chief Executive Officer and President (2016-); Chief Operating Officer and President (2015-2016); Executive Vice President and Chief Operating Officer (2014-2015); Executive Vice President Operations and Regulation (2013-2014); Senior Vice President and Chief Financial Officer (2004-2013).
Brody J. Wilson[2]	37	Chief Financial Officer, Treasurer, Chief Accounting Officer and Controller (2016-) Chief Accounting Officer, Controller and Assistant Treasurer (2016); Controller (2013-2015); Acting Controller (2013); Accounting Director (2012-2013); Senior Manager, PriceWaterhouseCoopers LLP (2009-2012); Manager, PriceWaterhouseCoopers LLP (2007-2009).
Lea Anne Doolittle	61	Senior Vice President and Chief Administrative Officer (2013-); Senior Vice President (2008-2013); Vice President, Human Resources (2000-2007).
MardiLyn Saathoff	60	Senior Vice President, Regulation and General Counsel (2016-); Senior Vice President and General Counsel (2015-2016); Vice President, Legal, Risk and Compliance (2013-2014); Deputy General Counsel (2010-2013); Chief Governance Officer and Corporate Secretary (2008-2014).
Grant M. Yoshihara	61	Senior Vice President, Utility Operations (2016-); Vice President, Utility Operations (2007-2016); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
Shawn M. Filippi	44	Vice President, Chief Compliance Officer and Corporate Secretary (2016-); Vice President and Corporate Secretary (2015-2016); Senior Legal Counsel (2011-2014); Assistant Corporate Secretary (2010-2014); Associate Legal Counsel (2005-2010).
Kimberly A. Heiting	47	Vice President, Communications and Chief Marketing Officer (2015-); Chief Marketing & Communications Officer (2013-2014); Chief Corporate Communications Officer (2011-2013); Communications Director (2005-2011).
Ngoni Murandu	42	Vice President and Chief Information Officer (2016-); Chief Information Officer (2014-2016); Senior Vice President and Chief Information Officer, NANA Development Corporation (2010-2014).
Thomas J. Imeson	66	Vice President of Public Affairs (2014-); Director of Public Affairs, Port of Portland (2006-2014).
Justin Palfreyman	38	Vice President of Business Development (2016-); Director, Power, Energy and Infrastructure Group, Lazard, Freres & Co. (2009-2016).
Lori Russell	57	Vice President, Utility Services (2016-); Utility Field Operations Director (2013-2016); Serve Customer Process Director (2008-2013).

David A. Weber	57	President and Chief Executive Officer, NW Natural Gas Storage, LLC and Gill Ranch Storage, LLC (2012-); Interim President and Chief Executive Officer, NW Natural Gas Storage, LLC and Gill Ranch Storage, LLC (2011-2012); Chief Operating Officer, NW Natural Gas Storage, LLC and Gill Ranch Storage, LLC (2010-2011); Managing Director of Information Services and Chief Information Officer (2005-2011); Director of Information Services and Chief Information Officer (2001-2005).

(1) Mr. Kantor served as the Company's Chief Executive Officer until the transition of the role to Mr. Anderson on August 1, 2016. After that time Mr. Kantor served as an advisor to the Board of Directors until his retirement from the Company on December 31, 2016.

(2) Gregory C. Hazelton resigned from his position as Senior Vice President, Chief Financial Officer and Treasurer of the Company effective September 2, 2016, at which time Mr. Wilson was appointed interim Chief Financial Officer and interim Treasurer in addition to continuing as Controller and Chief Accounting Officer.

Each executive officer serves successive annual terms; present terms end on May 25, 2017. There are no family relationships among our executive officers, directors or any person chosen to become one of our officers or directors.

NW Natural has adopted a Code of Ethics (Code) applicable to all employees and officers that is available on our website at www.nwnatural.com. We intend to disclose on our website at www.nwnatural.com any amendments to the Code or waivers of the Code for executive officers.

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ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation", "Report of the Organization and Executive Compensation Committee", and "Compensation Committee Interlocks and Insider Participation" contained in our definitive Proxy Statement for the May 25, 2017 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2016 is reflected in Part III, Item 10, above.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth information regarding compensation plans under which equity securities of NW Natural are authorized for issuance as of December 31, 2016 (see Note 6 to the Consolidated Financial Statements):

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
LTIP Performance Share Awards (Target Award)[1][2]	113,674	n/a	365,633
LTIP Restricted Stock Units (Target Award)[1][2]	89,973	n/a	365,633
LTIP Stock Options[3]	—	—	615,633
Restated Stock Option Plan	180,163	$ 44.38	—
Employee Stock Purchase Plan	18,830	50.47	41,831
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)[4]	1,195	n/a	n/a
Directors Deferred Compensation Plan (DDCP)[4]	45,986	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)[5]	161,048	n/a	n/a
Total	610,869		657,464

(1) Shares issued pursuant to Performance Share Awards and Restricted Stock Units under the LTIP do not include an exercise price, but are payable when the award criteria are satisfied. If the maximum awards were paid pursuant to the Performance Share Awards outstanding at December 31, 2016, the number of shares shown in column (a) would increase by 113,674 shares and the number of shares shown in column (c) would decrease by the same amount of shares.

(2) The aggregate 365,633 shares are available for future issuance under the LTIP as Restricted Stock Units, Performance Share Awards, or stock options. An additional 250,000 shares are available for LTIP Stock Option Issuance at December 31, 2016, but those additional shares are not available for issuance of LTIP Restricted Stock

Units or Performance Share Awards.

(3) Shares balance includes 365,633 shares available for future issuance under the LTIP as Restricted Stock Units, Performance Share Awards, or stock options, and an additional 250,000 shares available for LTIP Stock Option Issuance only at December 31, 2016, which are not available for issuance of LTIP Restricted Stock Units or Performance Share Awards.

(4) Prior to January 1, 2005, deferred amounts were credited, at the participant's election, to either a "cash account" or a "stock account." If deferred amounts were credited to stock accounts, such accounts were credited with a number of shares of NW Natural common stock based on the purchase price of the common stock on the next purchase date under our Dividend Reinvestment and Direct Stock Purchase Plan, and such accounts were credited with additional shares based on the deemed reinvestment of dividends. Cash accounts are credited quarterly with interest at a rate equal to Moody's Average Corporate Bond Yield plus two percentage points, subject to a 6% minimum rate. At the election of the participant, deferred balances in the stock accounts are payable after termination of Board service or employment in a lump sum, in installments over a period not to exceed 10 years in the case of the DDCP, or 15 years in the case of the EDCP, or in a combination of lump sum and installments. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participant's stock accounts. We have contributed common stock to the trustee of the Umbrella Trusts such that the Umbrella Trusts hold approximately the number of shares of common stock equal to the number of shares credited to all participants' stock accounts.

(5) Effective January 1, 2005, the EDCP and DDCP were closed to new participants and replaced with the DCP. The DCP continues the basic provisions of the EDCP and DDCP under which deferred amounts are credited to either a "cash account" or a "stock account." Stock accounts represent a right to receive shares of NW Natural common stock on a deferred basis, and such accounts are credited with additional shares based on the deemed reinvestment of dividends. Effective January 1, 2007, cash accounts are credited quarterly with interest at a rate equal to Moody's Average Corporate Bond Yield. Our obligation to pay deferred compensation in accordance with the terms of the DCP will generally become due on retirement, death, or other termination of service, and will be paid in a lump sum or in installments of five, 10, or 15 years as elected by the participant in accordance with the terms of the DCP. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participant's stock accounts. We have contributed common stock to the trustee of the Supplemental Trust such that this trust holds approximately the number of common shares equal to the number of shares credited to all participants' stock accounts. The right of each participant in the DCP is that of a general, unsecured creditor of the Company.

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The information captioned “Beneficial Ownership of Common Stock by Directors and Executive Officers” and "Security Ownership of Common Stock of Certain Beneficial Owners" contained in our definitive Proxy Statement for the May 25, 2017 Annual Meeting of Shareholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information captioned "Transactions with Related Persons" and "Corporate Governance" in the Company’s definitive Proxy Statement for the May 25, 2017 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2016 and 2015 Audit Firm Fees" in the Company’s definitive Proxy Statement for the May 25, 2017 Annual Meeting of Shareholders is hereby incorporated by reference.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

1. A list of all Financial Statements and Supplemental Schedules is incorporated by reference to Item 8.

2. List of Exhibits filed:

Reference is made to the Exhibit Index commencing on page 95.

ITEM 16. FORM 10-K SUMMARY

None.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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

By: /s/ David H. Anderson
David H. Anderson
President and Chief Executive Officer
Date: February 27, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Signature	Title	Date
/s/ David H. Anderson	Principal Executive Officer and Director	February 27, 2017
David H. Anderson President and Chief Executive Officer		
/s/ Brody J. Wilson	Principal Financial Officer and Principal Accounting Officer	February 27, 2017
Brody J. Wilson Chief Financial Officer, Chief Accounting Officer, Treasurer and Controller		
/s/ Timothy P. Boyle Timothy P. Boyle	Director	)))
/s/ Martha L. Byorum Martha L. Byorum	Director	)))
/s/ John D. Carter John D. Carter	Director	)))
/s/ Mark S. Dodson Mark S. Dodson	Director	))

		February 27, 2017
/s/ C. Scott Gibson	Director	)
C. Scott Gibson		)
		)
/s/ Tod R. Hamachek	Director	)
Tod R. Hamachek		)
		)
/s/ Jane L. Peverett	Director	)
Jane L. Peverett		)
		)
/s/ Kenneth Thrasher	Director	)
Kenneth Thrasher		)
/s/ Malia H. Wasson	Director	)
Malia H. Wasson		)

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NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Annual Report on Form 10-K
For the Fiscal Year Ended December 31, 2016

Exhibit Number	Document
*3a.	Restated Articles of Incorporation, as filed and effective May 31, 2006 and amended June 3, 2008 (incorporated herein by reference to Exhibit 3.1 to Form 10-Q for the quarter ended June 30, 2008, File No. 1-15973).
*3b.	Bylaws as amended May 22, 2014 (incorporated herein by reference to Exhibit 3.1 to Form 8-K dated May 22, 2014, File No. 1-15973).
*4a.	Copy of Mortgage and Deed of Trust, dated as of July 1, 1946, to Bankers Trust (to whom Deutsche Bank Trust Company Americas is now successor), Trustee (incorporated herein by reference to Exhibit 7(j) in File No. 2-6494); and copies of Supplemental Indentures Nos. 1 through 14 to the Mortgage and Deed of Trust, dated respectively, as of June 1, 1949, March 1, 1954, April 1, 1956, February 1, 1959, July 1, 1961, January 1, 1964, March 1, 1966, December 1, 1969, April 1, 1971, January 1, 1975, December 1, 1975, July 1, 1981, June 1, 1985 and November 1, 1985 (incorporated herein by reference to Exhibit 4(d) in File No. 33-1929); Supplemental Indenture No. 15 to the Mortgage and Deed of Trust, dated as of July 1, 1986 (filed as Exhibit 4(c) in File No. 33-24168); Supplemental Indentures Nos. 16, 17 and 18 to the Mortgage and Deed of Trust, dated, respectively, as of November 1, 1988, October 1, 1989 and July 1, 1990 (incorporated herein by reference to Exhibit 4(c) in File No. 33-40482); Supplemental Indenture No. 19 to the Mortgage and Deed of Trust, dated as of June 1, 1991 (incorporated herein by reference to Exhibit 4(c) in File No. 33-64014); Supplemental Indenture No. 20 to the Mortgage and Deed of Trust, dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4(c) in File No. 33-53795); Supplemental Indenture No. 21 to the Mortgage and Deed of Trust, dated as of October 15, 2012 (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 26, 2012, File No. 1-15973); and Supplemental Indenture No. 22 to the Mortgage and Deed of Trust, dated as of November 1, 2016 (incorporated herein by reference to Exhibit 4.1 to Form 10-Q for the quarter ended September 30, 2016, File No. 1-15973).
*4b.	Form of Secured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 4, 2004, File No. 1-15973).
*4c.	Copy of Indenture, dated as of June 1, 1991, between the Company and Bankers Trust Company, Trustee, relating to the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4(e) in File No. 33-64014).
*4d.	Form of Credit Agreement among Northwest Natural Gas Company and the parties thereto, with JPMorgan Chase Bank, N.A. as administrative agent and U.S. Bank, N.A. and Wells Fargo Bank, N.A. as co-syndication agents, dated as of December 20, 2012 (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated December 20, 2012, File No.1-15973).
*4e.	Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, extending the maturity date of the Credit Agreement between Northwest Natural Gas Company and each financial institution, effective as of December 20, 2013 (incorporated herein by reference to Exhibit 4k to Form 10-K for 2013, File No. 1-15973).

*4f. Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, extending the maturity date of the Credit Agreement between Northwest Natural Gas Company and each financial institution, effective as of December 20, 2014 (incorporated herein by reference to Exhibit 4m to Form 10-K for 2014, File No. 1-15973).

*4g. First Amendment to Credit Agreement, between the Company JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, dated as of December 20, 2014 (incorporated herein by reference to Exhibit 4n to Form 10-K for 2014, File No. 1-15973).

12 Statement re computation of ratios of earnings to fixed charges.

21 Subsidiaries of Northwest Natural Gas Company.

23	Consent of PricewaterhouseCoopers LLP.
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.

Executive Compensation Plans and Arrangements:

*10a.	Executive Supplemental Retirement Income Plan 2010 Restatement (incorporated herein by reference to Exhibit 10b. to Form 10-K for 2009, File No. 1-15973).
*10b.	Supplemental Executive Retirement Plan, 2011 Restatement (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2011, File No. 1-15973).
*10c.	Northwest Natural Gas Company Supplemental Trust, effective January 1, 2005, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.7 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10d.	Northwest Natural Gas Company Umbrella Trust for Directors, effective January 1, 1991, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.5 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10e.	Northwest Natural Gas Company Umbrella Trust for Executives, effective January 1, 1988, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.6 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10f.	Restated Stock Option Plan, as amended effective December 14, 2006 (incorporated herein by reference to Exhibit 10c. to Form 10-K for 2006, File No. 1-15973).
*10g.	Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10h. to Form 10-K for 2009, File No. 1-15973).
*10h.	Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10e. to Form 10-K for 2008, File No. 1-15973).
*10i.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10f. to Form 10-K for 2008, File No. 1-15973).
*10j.	Deferred Compensation Plan for Directors and Executives, effective January 1, 2005, restated as of July 28, 2016 (incorporated herein by reference to Exhibit 10.3 to Form 10-Q for the quarter ended June 30, 2016, File No. 1-15973).

*10k.	Form of Indemnity Agreement as entered into between the Company and each director and certain executive officers (incorporated herein by reference to Exhibit 10l. to Form 10-K for 2009, File No. 1-15973).
*10l.	Form of Indemnity Agreement as entered into between the Company and certain executive officers (incorporated herein by reference to Exhibit 10l.(1) to Form 10-K for 2009, File No. 1-15973).
*10m.	Non-Employee Directors Stock Compensation Plan, as amended effective December 15, 2005 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10n.	Executive Annual Incentive Plan, effective February 23, 2012, as amended effective January 1, 2016 (incorporated herein by reference to Exhibit 10p. to Form 10-K for 2015, File No. 1-15973).

10o.	Executive Annual Incentive Plan, effective January 1, 2017.
*10p.	Form of Change in Control Severance Agreement between the Company and each executive officer (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2008, File No. 1-15973).
*10q.	Northwest Natural Gas Company Long Term Incentive Plan, as amended and restated effective May 24, 2012 (incorporated herein by reference to Exhibit 10r to Form 10-K for 2012, File No. 1-15973).
*10r.	Severance Agreement between Northwest Natural Gas Company and an executive officer, dated as of June 30, 2015 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated June 24, 2015, File No. 1-15973).
*10s.	Form of Long Term Incentive Award Agreement under the Long Term Incentive Plan (2014-2016) (incorporated herein by reference to Exhibit 10v. to Form 10-K for 2013, File No. 1-15973).
*10t.	Form of Long Term Incentive Award Agreement under the Long Term Incentive Plan (2015-2017) (incorporated by reference to Exhibit 10w. to Form 10-K for 2014, File No. 1-15973).
*10u.	Form of Long Term Incentive Award Agreement under the Long Term Incentive Plan (2016-2018) (incorporated herein by reference to Exhibit 10w. to Form 10-K for 2015, File No. 1-15973).
*10v.	Form of Long Term Incentive Award Agreement under the Long Term Incentive Plan between the Company and an Executive Officer (2016-2018) (incorporated herein by reference to Exhibit 10x. to Form 10-K for 2015, File No. 1-15973).
*10w.	Agreement to Amend the Long Term Incentive Award Agreement, under the Long Term Incentive Plan dated February 25, 2016 by and between the Company and an executive officer (incorporated herein by reference to Exhibit 10y. to Form 10-K for 2015, File No. 1-15973).
10x.	Form of Long Term Incentive Award Agreement under Long Term Incentive Plan (2017-2019).
*10y.	Form of Consent dated December 14, 2006 entered into by each executive officer with respect to amendments to the Executive Supplemental Retirement Income Plan, the Supplemental Executive Retirement Plan and certain change in control severance agreements (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10z.	Consent to Amendment of Deferred Compensation Plan for Directors and Executives, dated February 28, 2008 entered into by each executive officer (incorporated herein by reference to Exhibit 10bb to Form 10-K for 2007, File No. 1-15973).
10aa.	Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2017).
*10bb.	Form of Restricted Stock Unit Award Agreement under Long Term Incentive Plan (2016) (incorporated herein by reference to Exhibit 10bb. to Form 10-K for 2015, File No. 1-15973).
10cc.	Form of Amendment to Restricted Stock Unit Award Agreements (2013, 2014 and 2015).

*10dd.	Form of Restricted Stock Unit Award Agreement under the Long Term Incentive Plan (2013) (incorporated herein by reference to Exhibit 10aa. to Form 10-K for 2012, File No. 1-15973).
*10ee.	Form of Restricted Stock Unit Award Agreement under the Long Term Incentive Plan (2012) (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 20, 2011, File No. 1-15973).
*10ff.	Form of Special Restricted Stock Unit Award Agreement under the Long Term Incentive Plan between the Company and an executive officer (incorporated herein by reference to Exhibit 10cc. to Form 10-Q for the period ending September 30, 2013, File No. 1-15973).

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*10gg.	Form of Special Restricted Stock Unit Award Agreement under the Long Term Incentive Plan between the Company and an executive officer (incorporated herein by reference to Exhibit 10a. to Form 10-Q for the quarter ended March 31, 2014, File No. 1-15973).
*10hh.	Form of Special Retention Restricted Stock Unit Award Agreement between the Company and an executive officer, dated as of June 30, 2015 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated June 24, 2015, File No. 1-15973).
*10ii.	Hire-On Bonus Agreement between the Company and an executive officer, dated as of June 30, 2015 (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated June 24, 2015, File No. 1-15973).
*10jj.	Form of Director Restricted Stock Unit Award Agreement under Long Term Incentive Plan (incorporated herein by reference to Exhibit 10a. to Form 10-Q for the quarter ended March 31, 2016, File No. 1-15973).
*10kk.	Severance Agreement between Northwest Natural Gas Company and an executive officer, dated August 1, 2016 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated July 28, 2016, File No. 1-15973).
*10ll.	Form of Restricted Stock Unit Award Agreement between the Company and an executive officer dated as of July 27, 2016 (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2016, File No. 1-15973).
*10mm.	Amended and Restated Cash Retention Agreement between the Company and an executive officer, dated as of July 28, 2016 (incorporated herein by reference to Exhibit 10.2 to Form 10-Q for the quarter ended June 30, 2016, File No. 1-15973).
*10nn.	Form of Special Restricted Stock Unit Award Agreement under Long Term Incentive Plan between the Company and an executive officer, dated as of September 30, 2016 (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2016, File No. 1-15973).
10oo.	Annual Incentive Plan for NW Natural Gas Storage, LLC, as amended effective January 1, 2017.
10pp.	Long Term Incentive Plan for NW Natural Gas Storage, LLC, as amended effective January 1, 2016.
101.	The following materials from Northwest Natural Gas Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2016, formatted in Extensible Business Reporting Language (XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.

*Incorporated herein by reference as indicated

**Pursuant to Item 601(b)(32)(ii) of Regulation S-K, this certificate is not being "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.