NORTHWEST NATURAL GAS CO
Form 10-K
February 28, 2014

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, 2013
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ___________ to____________
Commission file number 1-15973

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

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

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

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.
[X]
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 28, 2013, the registrant had 26,972,022 shares of its Common Stock outstanding, of which 26,636,200 shares were held by non-affiliates. 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 $1,131,505,776.
At February 21, 2014, 27,099,729 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 2014 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, 2013

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GLOSSARY OF TERMS

AVERAGE WEATHER: equal to the 25-year average degree days based on temperatures established in our last Oregon general rate case.

Bcf: one billion cubic feet, a volumetric measure of natural gas, 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.

CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC): entity that regulates our California gas storage business at our Gill Ranch facility with respect to rates and terms of service, among other matters.

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.

DECOUPLING: a rate mechanism, also referred to as our conservation tariff, which is designed to break the link between earnings and the quantity of natural gas consumed by customers. The design is intended to allow the utility to encourage customers to conserve energy while not adversely affecting its earnings due to reductions in sales volumes.

HEATING DEGREE DAYS: units of measure that reflect temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day's high and low temperatures from 65 degrees Fahrenheit.

DEMAND COST: a component in core utility customer rates that covers the cost of securing firm pipeline capacity, whether that capacity is used or not.

FEDERAL ENERGY REGULATORY COMMISSION (FERC): entity that regulates 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.

GENERAL RATE CASE: a periodic filing with state or federal regulators to establish billing rates for all classes of utility customers.

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.

LIQUEFIED NATURAL GAS (LNG): 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.

PUBLIC UTILITY COMMISSION OF OREGON (OPUC): 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.

PURCHASED GAS ADJUSTMENT (PGA): 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.

RETURN ON EQUITY (ROE): 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 revenue requirements.

SALES SERVICE: service provided whereby a customer purchases both natural gas commodity supply and transportation from the utility.

SITE REMEDIATION AND RECOVERY MECHANISM (SRRM): an Oregon rate mechanism for recovering prudently incurred environmental site remediation costs through customer billings, subject to an earnings test.

SYSTEM INTEGRITY PROGRAM (SIP): an Oregon rate mechanism that provides cost recovery of pipeline and system integrity programs, which are required under various safety standards prescribed by both state and federal regulators.

THERM: the basic unit of natural gas measurement, equal to one hundred thousand Btu’s.

TRANSPORTATION SERVICE: service provided whereby a customer purchases natural gas commodity 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.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION (WUTC): entity that regulates our Washington utility business with respect to rates and terms of service, among other matters.

WEATHER NORMALIZATION: an Oregon rate mechanism applied to residential and commercial customers’ bills to adjust for 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.

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FORWARD-LOOKING STATEMENTS

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

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

The utility business is our largest segment, while our gas storage businesses account for a majority of our remaining net income. The following table reflects the percentage allocation between segments and other as of December 31, 2013:

	Utility	Non-Utility[1] Gas Storage[2]	Other	Total
Assets	89.0 %	10.4 %	0.6 %	100.0 %
Net Income	90.7 %	9.2 %	0.1 %	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] 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 approximately 695,000 customers with around 90% of our customers located in Oregon and 10% located in Washington. In total, we provide natural gas service to over 100 cities in 18 counties with an estimated population of 3.4 million in our service territory.

The OPUC and WUTC have allocated us an exclusive service territory, 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 that comprises ocean and river shipping, transcontinental railways and highways, and an international airport. The area is a major retail and manufacturing center and home to high-technology industries.

Customers

We serve residential, commercial and industrial customers with no individual customer or industry accounting for over 10% of our utility revenues. 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 other items. The following table presents summary customer information as of December 31, 2013:

	Number of Customers	% of Volumes		% of Utility Margin	
Residential	628,634	36	%	64	%
Commercial	65,321	22	%	27	%
Industrial	918	42	%	8	%
Other[1]	N/A	N/A		1	%
Total	694,873	100	%	100	%

[1] Other is derived from miscellaneous services, gains or losses from our incentive gas cost 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 election of services, special charges for changes between elections, and in some cases, meeting a minimum or maximum volume requirement before changing options.

Customer growth rates for natural gas utilities in the Pacific Northwest are generally 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 that natural gas is in less than 60% of residential single-family dwellings in our service territory. Therefore, growth in the region comes from both new housing construction and existing homes converting to natural gas. Prior to the most recent recession, our customer growth rate averaged around 3% or higher. From 2009 to 2012, growth dipped below 1%, but in 2013, the

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12-month growth rate increased to 1.3%. With natural gas' continued price advantage, operating convenience, and environmental benefits, we believe there is potential for continued growth in all customer categories as the economy recovers. 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, market conditions, technology, federal and state energy policy, and environmental impacts.

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

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 that confront a number of our largest customers that compete 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 margin if customers bypass or switch over to custom contracts that provide 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.

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. In December 2013, we filed a

rate petition 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. Our current approved rates and recovery mechanisms for each service area include:

	Oregon	Washington[1]
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
Incentive Sharing	X	
Weather Normalization Tariff	X	
Decoupling	X	
SIP	X	
Pension Balancing	X	
Environmental Cost Deferral	X	X
SRRM	X	

(1)Although we do not have the same specific regulatory mechanisms in Washington, we do have approved regulatory deferral orders that allow us to defer certain costs for future recovery through the PGA or future general rate cases, such as our environmental cost deferral order.

In general, these rates and regulatory mechanisms do not provide for the utility to earn a profit or incur a loss on our gas commodity purchases. This means gas commodity purchase costs are primarily a pass-through cost in customer rates, with the exception of our incentive cost sharing mechanism in Oregon. Under this mechanism, we can either increase or decrease margin revenues based on higher or lower actual gas purchase costs compared to gas purchase costs embedded in the PGA and our gas reserve investment. We can earn an authorized return on the equivalent rate base investment on our gas reserves.

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" below.

Gas Supply

The utility strives to secure sufficient, reliable supplies of natural gas to meet the needs of customers at the lowest reasonable cost through a comprehensive strategy that is focused on the following items:

- Diverse Supply - providing diversity of supply sources;
- Diverse Contracts - maintaining a variety of contract durations and types; and
- Cost Management - employing 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 optimize price

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differentials. Currently, about 63% of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. We believe that 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. We believe that 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, we have seen increased availability of gas supplies throughout North America as a result of the extraction of shale gas and the building of new transmission pipelines to increase transportation capacity out of the U.S. Rocky Mountain region.

We supplement our firm gas supply purchases with gas withdrawals from gas storage facilities, including underground reservoirs, and LNG storage facilities. These storage facilities are generally injected with natural gas during off-peak months during the spring and summer and are 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)	Capacity (Bcf)
Gas Storage Facilities:		
Owned Facility:		
Mist, Oregon[1]	2.7	10.0
Contracted Facilities:		
Jackson Prairie, Washington[2]	0.5	1.1
Alberta, Canada[3]	0.5	2.8
LNG Facilities:		
Owned Facilities:		
Newport, Oregon	0.6	0.9
Portland, Oregon	1.2	0.6
Contracted Facility:		
Plymouth, Washington[4]	0.6	0.5
Total	6.1	15.9

t1) The Mist gas storage facility has a total maximum daily deliverability of 5.2 million therms and a total working gas capacity of about 16 Bcf, of which 2.7 million therms of daily deliverability and 10 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 does help to manage price risks as it displaces equivalent volumes of spot purchases.
(4) On certain days in December 2013, pipeline transportation service from the Plymouth facility was curtailed. As a result, we no longer assume that the resource will contribute to total peak day capacity beginning with the 2014-2015 heating season. We are currently evaluating this resource and alternative options, but will continue to utilize the facility to manage price risks in the coming year.

The Mist facility is used for both utility and non-utility purposes. Under our regulatory agreement with the OPUC,

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 addition, we have the ability to recall pipeline capacity and supply resources from certain customers if needed.

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 plus 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.

During 2013, we purchased a total of 762 million therms under contracts with durations outlined in the chart below:

Contract Duration (primary term)	Percent of Purchases	
Long-term (one year or longer)	28	%
Short-term (more than one month, less than one year)	24	
Spot (one month or less)	48	
Total	100	%

We renew or replace gas supply contracts as they expire. Aside from the gas supplies provided by an independent energy marketing company as part of asset management services, our largest individual supplier provided just over 10% of our gas supply requirements in 2013.

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 store and transport gas to our distribution system; our gas reserves contract; 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 effectively (1) 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";
- buying physical gas supplies at a set price and injecting it into storage for price stability and to minimize pipeline capacity demand costs;

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- investing in gas reserves for longer term price stability with Encana Oil & Gas (USA) Inc. (Encana). See Note 11; and
- using an asset management service provider to produce incremental revenues that are used to reduce our utility's net cost of gas.

We contract with an independent energy marketing company to capture opportunities regarding our unused 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 an opportunity to generate incremental revenues for NW Natural's shareholders from a regulatory incentive-sharing mechanism, which are included in our gas storage segment.

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.

In 2003, a federal order requiring Northwest Pipeline to replace its 26-inch mainline from the Canadian border to our service territory underscored the potential need for pipeline transportation diversity. That replacement project was completed by Northwest Pipeline in November 2006. We are pursuing options to further diversify the pipeline transportation system into our service territory. Specifically, we are jointly developing plans to build a pipeline that 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. See Part II, Item 7, "2014 Outlook".

We incur monthly demand charges related to our firm pipeline transportation contracts. Our largest pipeline agreements are with Northwest Pipeline for firm transportation capacity, which provides access to supplies in British Columbia and the U.S. Rocky Mountains by connecting us with the Northwest Pipeline and GTN systems. These contracts are multi-year contracts with expirations ranging from 2014 to 2044. We actively work with Northwest Pipeline and others to renew contracts in advance of expiration and ensure gas transportation capacity is sufficient to meet our needs.

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

Gas Distribution

The goals of our gas distribution operations are:

- Safety - Building and maintaining a safe pipeline distribution system;
- Reliability - Ensuring gas resource portfolios that are sufficient to satisfy customer requirements under extremely cold weather conditions; and
- Lowest Reasonable Cost - Acquiring gas supplies at the lowest reasonable cost for utility customers;
- Price Stability - Managing commodity price volatility by making the best use of physical assets and financial instruments; and
- Cost Recovery - Managing gas purchase costs to minimize risks associated with regulatory prudence reviews and cost recovery.

These goals are discussed more fully in the following sections.

Safety

Safety and the protection of our employees, our customers and the public at large are and will remain a top priority. We monitor and maintain our pipeline distribution system and storage operations with the goal of ensuring that natural gas is stored and delivered safely, reliably and efficiently. We have had various cost recovery mechanisms since 2004 and currently have a program that integrates the Company's programs for bare steel replacement, transmission pipeline integrity management, and distribution pipeline integrity management into a single program. 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 recent pipeline incidents involving other companies. Most recently, additional regulations from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) were drafted in 2013 with final regulations expected in 2015 and an effective date in 2016. We will continue to work diligently with industry associations as well as federal and state regulators to ensure the safety of our system and compliance with new laws and regulations. We expect that costs associated with compliance to federal, state, and local rules would be recoverable in rates.

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 three day design peak event that is based on the most severe cold weather experienced during the last 25 years in our service territory.

Our projected maximum design day firm utility customer sendout totals approximately 9.3 million therms. Of this total, we are currently capable of meeting over 50% of our maximum design day requirements with gas from storage located within or adjacent to our service territory, while the remaining supply requirements would be met by gas purchases under firm and recall gas purchase contracts.

On February 6, 2014, we experienced our current record customer sendout of 9.0 million therms, which included 7.4 million firm therms. This record day was approximately 9

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degrees Fahrenheit warmer than the design day temperature.

We believe that 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 that are projected to be used to satisfy the design day sendout for the 2013-2014 winter heating season:

Therms in millions	Therms	Percent	
Sources of utility supply:			
Firm supply purchases	3.3	37	%
Mist underground storage (utility only)	2.7	29	
Company-owned LNG storage	1.8	19	
Off-system firm storage contract	0.5	5	
Other off-system storage contract[(1)]	0.6	6	
Recall agreements	0.4	4	
Total	9.3	100	%

[(1)] On certain days in December 2013, pipeline transportation service from the Plymouth storage facility was curtailed. We were able to use this service in February 2014 primarily through other transportation agreements. We are currently evaluating this resource and alternative options for the 2014-2015 heating season.

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 receipt of the IRP; whereas the WUTC provides notice that our IRP met the requirements of the Washington Administrative Code. Commission acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. However, the OPUC generally indicates that it would give considerable weight in prudence reviews to utility actions that are consistent with acknowledged plans. The WUTC has indicated that the IRP process is one factor it will consider in a prudence review. We plan to file our 2014 IRP in both Oregon and Washington in May 2014.

Lowest Reasonable Cost

We apply cost management strategies, including fixed-price contracts, financial derivative instruments, storage supplies, acquisition of gas reserves, and asset management, to acquire gas supplies at the lowest reasonable cost for utility customers. See "Gas Supply—Gas Cost Management Strategy" above.

Price Stability

We use physical assets and financial instruments to manage commodity price volatility. We purchase gas for our

storage facility generally during the summer months when gas prices are typically lower. In addition, our gas reserves provide long-term gas price protection for our utility customers. We also mitigate year-to-year commodity price volatility through financial hedge contracts such as commodity price swaps and options.

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, 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."

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GAS STORAGE

The gas storage segment includes the following:
- the non-utility portion of the Mist gas storage facility near Mist, Oregon;
- our 75% share of the 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.

In recent years, as a result of the abundant supply of natural gas in North America, we have seen lower, more stable natural gas prices, which has created a challenging gas storage environment. In late 2013 and early 2014, we saw gas price volatility due to the colder than normal winter throughout North America. In the short-term, this gas price volatility increased the demand for, and value of, holding gas storage. However, future gas storage demand and pricing have been negatively affected by projections of spring and summer natural gas prices that are equal to projected gas prices for the winter of 2014-15, making the purchase of spring and summer gas for injection into storage less desirable. As a result of these current trends, we anticipate contracting for the upcoming storage year at lower market prices than in previous periods, especially at our California facility, where some multi-year contracts are expiring. In the longer term, increased demand for natural gas and/or decreased drilling activity could change the current supply/demand imbalance and result in higher gas prices or increased market volatility, which could position this segment for growth.
See Note 4 for more information on gas storage assets and results of operations and "Financial Condition—Liquidity and Capital Resources".

Gas Storage Facilities

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

	Storage Capacity (Bcf)	Maximum Deliverability (Bcf/day)[3]	Injection (Bcf/day)[3]
Mist Storage[1]	6	0.2	0.1
Gill Ranch Storage[2]	15	0.5	0.2

[1] Approximately 6 Bcf of a total 16 Bcf at Mist is currently available to our gas storage segment. The remaining 10 Bcf is used to provide gas storage for our local distribution business and its utility customers. All storage capacity and daily deliverability currently developed for the gas storage segment at Mist is available for recall by the utility.
[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 expected 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 its facility located in Columbia County, Oregon, near the town of Mist. The Mist field was converted to storage operations for our utility customers in 1989. Since 2001, gas storage capacity at Mist has 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 interstate 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 production or distribution, electric generation, and energy marketing. Three storage customers currently account for over 90% of our existing non-utility gas storage capacity at Mist, with the largest customer accounting for about half of the total capacity. These three customers have contracts that expire at various dates through 2018.

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 related to utility customers' lower demand during the spring and summer months. This surplus storage capacity 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. See Part II, Item 7, "Results of Operations–Regulatory Matters".

EXPANSION OPPORTUNITIES. The Pacific Northwest storage markets have been impacted by lower gas prices and lack of price volatility, although less than other areas of the country. The need for new, flexible gas-fired generation has been identified in the Pacific Northwest region to integrate intermittent wind resources into the power system, thereby increasing the associated need for gas storage. To address this need, we are in the early planning stages of a potential expansion of our Mist storage facility. If completed, this expansion would be anchored by an agreement to provide gas storage services to Portland General Electric (PGE) to support their gas-fired generation facilities at Port Westward, Oregon. The Mist expansion project is subject to PGE's approval of projected costs and various other approvals, regulatory requirements, and other conditions.

Gill Ranch 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 the fourth quarter of 2010 and currently 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 Bcf of working gas capacity.

California has been impacted by challenging market conditions for gas storage, with contract prices in the region at historic lows and a greater number of competitors in the area compared to the Pacific Northwest region. As a result, we anticipate contracting at lower market prices than we have in the previous years. We are committed to using a variety of contracting tools to maximize the value from the Gill Ranch facility. In the longer term, the recovery of the California economy and potentially an increased demand for flexible generation could increase demand for natural gas storage and increase price volatility.

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. The 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 28 years in duration; however, the majority of the contracted capacity is shorter term in nature due to current market conditions. In the near-term, we expect Gill Ranch to contract for terms mostly ranging from one to five years. For the 2013-14 gas storage year, Gill Ranch has several storage customers, with the largest single contract accounting for approximately 13% of our storage capacity. We are currently in the process of

contracting available capacity for the upcoming 2014-15 gas storage year and expect shorter contract lengths and lower prices reflecting current market 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 competes with a number of other storage providers, including local integrated gas companies and other independent storage operators in the northern California market. There could also be expansions and proposed new construction of storage capacity in northern California that may create increased competition.

SEASONALITY. 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 revenues. In addition, a significant portion of operating costs at Gill Ranch are subject to seasonality 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 that the Gill Ranch storage facility could support an additional 25 Bcf of storage capacity, bringing the total storage capacity to approximately 45 Bcf, of which our current rights would give us up to an additional 7.5 Bcf or ownership of a total of approximately 22.5 Bcf.

Asset Management

We contract with an independent energy marketing company to provide asset management services, primarily through the use of commodity transactions and pipeline capacity release transactions, the results of which 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".

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OTHER

We have immaterial 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. Palomar Gas Holdings, LLC (PGH) is owned 50% by NWN Energy, a wholly-owned subsidiary of NW Natural, and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. See Part II, Item 7, "2014 Outlook";
- 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.

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ENVIRONMENTAL ISSUES

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; and
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site.

We seek recovery of environmental costs through insurance and customer rates, and we believe recovery of these costs is probable. We currently have an open proceeding with the OPUC to resolve implementation issues for the SRRM, which allows for regulatory environmental cost recovery. As there is uncertainty surrounding the outcome of this proceeding, we will continue to carefully assess these environmental assets for recoverability. If it is determined that insurance recoveries for environmental costs are insufficient and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made. See Note 17 and Item 3 "Legal Proceedings" for information regarding the recent settlement with remaining defendant insurance companies. See also "Results of Operations—Rate Matters—Rate Mechanisms—Environmental Costs" below and Note 15.

Greenhouse Gas Issues

We recognize that 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 future emissions of greenhouse gases, including both carbon dioxide (CO_2) and methane. These future 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.

The outcome of federal and state policy development 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 fossil fuel with relatively low carbon content, it is also possible that 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 for use in vehicles.

We continue to take steps to address future greenhouse gas emission issues, including actively participating in policy development through participation on various Oregon taskforces and, at the federal level, within the American Gas Association. We engage in policy development and in identifying ways to reduce greenhouse gas emissions associated with our operations and our customers’ gas use, including offering 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, 2013, the utility workforce consisted of 612 members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO, and 469 non-union employees. Our labor agreement with members of OPEIU that covers wages, benefits and working conditions extends to May 31, 2014, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement. In 2013, each party served notice of intent to negotiate the terms of an agreement prior to the May 31, 2014 expiration date. We are currently engaged in negotiations to meet this schedule.

At December 31, 2013, our subsidiaries had a combined workforce of 19 non-union employees. 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.

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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, technology, and distribution system improvements. In 2014, utility capital expenditures are estimated to be between $115 and $135 million, and non-utility capital investments are estimated to be less than $10 million. Additional non-utility spend for gas storage and other investments during and after 2014 will depend largely on future decisions about potential expansion opportunities in gas storage and pipeline projects. For the five-year period ending in 2018, capital expenditures for the utility are estimated to be between $600 and $700 million, while the amount for gas storage and other investments after 2014 will depend largely on the factors discussed previously.

EXECUTIVE OFFICERS OF THE REGISTRANT

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

AVAILABLE INFORMATION

We file annual, quarterly and special reports and other information with the Securities and Exchange Commission (SEC). Reports, proxy statements and other information filed by us can be read and requested through the SEC by mail at U.S. Securities and Exchange Commission, Office of FOIA/PA Operations, 100 F Street, N.E., Washington, D.C. 20549, by facsimile at (202) 772-9337, 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 (202) 551-8090. The SEC website contains reports, proxy and information statements and other information that 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 us 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.

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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. 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 indicate 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, pension expense, transactions with affiliated interests, and other matters. Similarly, in our gas storage businesses FERC has regulatory authority over interstate storage services, and the CPUC has regulatory authority over our Gill Ranch storage operations.

The prices that the OPUC and WUTC allow us to charge for retail service, and the tariff rate that FERC permits us to charge for transmission, 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. For example, in our most recent Oregon rate case concluding in 2012, the OPUC disallowed certain deferred tax amounts for which the deferral was not previously reviewed by the OPUC, resulting in an after tax charge to net income when the order was received. 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.

In our latest general rate case with the OPUC, various items were deferred for future resolution in separate proceedings, including the definition of the earnings test under the SRRM, the prudence of environmental expenditures we have deferred to date, recovery of prepaid pension costs, and our revenue-sharing arrangement on the utility's interstate storage activities. The regulatory proceedings in which these issues will be resolved typically involve multiple parties, including governmental agencies, consumer advocacy groups, and others who are impacted by the use of natural gas. Each party has differing concerns, but all generally have the common objective of limiting amounts included in rates. We cannot predict the 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 already been recorded for estimated costs pursuant to a deferral order from the OPUC and WUTC. In addition to maintaining regulatory deferrals, we initiated litigation against certain of our historical liability insurers for a portion of the costs we have incurred to date and expect to incur in the future. To the extent amounts we recover 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 asset 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 an earnings test, the definition of which was deferred to a later regulatory proceeding. These prudence reviews and earnings tests could reduce the amounts we are allowed to recover, and which could adversely affect our financial condition, results of operations and cash flows.

In addition to litigation against historical insurers, we may have disputes with regulators and other parties as to the severity of particular environmental matters and what remediation efforts are appropriate. We cannot predict with certainty the amount or timing of future expenditures related to environmental investigation, remediation or other action, 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 the probable level of involvement, and 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. Current and additional environmental regulations could result in increased compliance costs or additional operating restrictions and 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.

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 cross-Cascades pipeline in Oregon, and a potential 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. With respect to these projects, 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 cross-Cascades pipeline, Gill Ranch storage and Encana gas reserves. 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

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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 venture with Encana, which operates as a hedge backed by physical gas supplies, involves 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 law 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 gas reserves venture with Encana 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, which 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 hydrocarbons 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 unpredicted 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;
- 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 outcome 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, and other extreme events to which we may not able to promptly respond.

Local or national disasters, pandemic illness, terrorist activities, including cyber attacks, 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 cyber attacks, which could target or impact our natural gas distribution, transmission or storage facilities and result in a disruption in our operations and ability 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, which could increase the risk that an event could adversely affect our operations or financial results.

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 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. 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 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 aging employees retire. 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 (the Union), and are covered by a collective bargaining agreement that extends to May 31, 2014. Disputes with the Union over terms and conditions of the agreement 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 Mist gas storage, which could strain relationships with customers and state regulators and cause a loss of revenues. Our collective bargaining agreement may also increase the cost of employing our Union workforce, affect our ability to continue offering market-based salaries and employee benefits, limit our flexibility in dealing with our workforce, and limit 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. 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 applicable to them. 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 interpretation 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 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 and accidents in other parts of the country, we anticipate that the natural gas industry may be the subject of even greater federal, state and local regulatory oversight. We intend to work diligently with industry associations and federal and state regulators to ensure compliance with the new laws. We expect there to be increased costs associated with compliance these laws, 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 reserve transaction with Encana which is a hedge backed by physical gas supplies. While we have risk management procedures for hedging in place, they may not always work

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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 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 hedge accounting under generally accepted accounting standards, our hedges may not be effective and our results of operations and financial condition could be adversely affected.

We also have credit-related exposure to derivative counterparties. In general, we require our counterparties to have an investment-grade credit rating at the time the derivative instrument is entered into, and we specify limits on the contract amount and duration based on each counterparty's credit rating. Nevertheless, 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.

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.

Risks Related Primarily to Our Local Utility Business

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 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 fuel 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,

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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 fuel sources and growing commercial use of natural gas. Insufficient growth in these markets, for economic, political or other reason 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, propane, and renewable energy providers. 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 could also 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 which 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, 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 10% 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 commercial customers' consumption. However, we do not have a conservation tariff in Washington that provides us this protection.

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.

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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, 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. Additionally, 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, 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. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. 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 operation 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 ongoing expansions and proposed construction of 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.

THIRD-PARTY PIPELINE RISK. Our gas storage businesses depends 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 operation is 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 reason, our ability to operate efficiently and satisfy our customers' needs could be compromised, thereby potentially could have an adverse impact on our financial condition, results of operations and cash flows.

OPERATIONS AT NEW STORAGE FACILITY RISK. Operations at our new Gill Ranch storage facility involves numerous operational risks that may result in a failure to meet expectations or contractual obligations, additional or unexpected costs and other business risks that could adversely impact our financial condition, results of operations and cash flows.

In October 2010, we commenced operations at our Gill Ranch storage facility. Operations at a new storage facility involve many risks. Although we believe that Gill Ranch storage facility has been successfully completed to meet our contractual obligations and project specifications with respect to injection, withdrawal and gas specifications, the facility is new, and has a limited operating history. If we fail to inject or withdraw natural gas at the levels we expect or at contracted rates, or cannot deliver natural gas consistent with our expectations or contractual specifications, or otherwise operate as expected, or if operating costs are substantially higher than we expect or if we fail to control those costs, we may not be able to contract for storage at the levels and on the terms we expect, and we could incur higher than expected costs to satisfy our contractual obligations under contracts we obtain, and this could adversely impact 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, 2018. 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.

In order to reduce risks associated with gas leakage in older parts of our system, we undertook an accelerated pipe replacement program under which we removed and replaced 100% of our cast iron mains by the end of 2000. In 2001, we initiated an accelerated pipe replacement program under which we expect to eliminate all remaining bare steel mains and services in the system by the end of 2015.

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 project.

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 and as discussed below, we have only nonmaterial litigation in the ordinary course of business.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon, Case Number 1012-17532. The defendants include Associated Electric & Gas Insurance Services Limited, Allianz Global Risk US Insurance Company, certain underwriters at Lloyd's London, certain London market insurance companies and 10 other insurance companies. In the suit, NW Natural alleged that the defendant insurance companies issued third party liability insurance policies to NW Natural and that the defendants had breached the terms of those policies by failing to reimburse and indemnify NW Natural for liabilities arising from environmental contamination at certain sites caused or alleged to be caused by its historical operations.

NW Natural sought damages in excess of $50 million in losses it had incurred through the date of the complaint, as well as declaratory relief for additional damages it expected to incur in the future. Settlements with certain of the defendant insurance companies resulted in payments received by NW Natural through December 31, 2013 of approximately $48 million.

In January and February 2014, the remaining defendant insurance companies agreed to settle all of NW Natural’s claims for insurance recovery for past and future environmental remediation expenses. In 2014 the Company expects to receive additional payments aggregating approximately $102 million under these settlement agreements signed in 2013 and 2014. Such payments are to be made in the first and second quarters of 2014. As a result of such settlements, the Company anticipates dismissal of the litigation in the second quarter of 2014. See Note 17.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR THE 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 closing trades for our common stock during the past two years were as follows:

	2013		2012	
Quarter Ended	High	Low	High	Low
March 31	$46.55	$43.40	$49.49	$44.40
June 30	45.89	41.17	48.56	43.90
September 30	45.15	39.96	50.16	46.04
December 31	44.35	40.75	50.80	41.01

The closing quotations for our common stock on December 31, 2013 and 2012 were $42.82 and $44.20, respectively.

As of February 21, 2014, there were 6,178 holders of record of our common stock.

We have paid quarterly dividends on our common stock in each year since the stock first was issued to the public in 1951. Annual common dividend payments per share, adjusted for stock splits, have increased each year since 1956. Dividends per share paid during the past two years were as follows:

Payment Date	2013	2012
February 15	$0.455	$0.445
May 15	0.455	0.445
August 15	0.455	0.445
November 15	0.460	0.455
Total per share	$1.825	$1.790

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, 2013:

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
10/01/13-10/31/13	—	$—	—	—
11/01/13-11/30/13	3,406	42.31	—	—
12/01/13-12/31/13	231	43.16	—	—
Total	3,637	$42.37	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2013, 3,637 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, 2013, no

shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated SOP.

(2) We have a common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2014 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended December 31, 2013, 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	2013	2012	2011	2010	2009
Operating revenues[(1)]	$758,518	$730,607	$828,055	$792,115	$988,055
Net income[(1)]	60,538	58,779	63,044	72,013	74,632
Earnings per share of common stock:					
Basic[(1)]	$2.24	$2.19	$2.36	$2.71	$2.82
Diluted[(1)]	2.24	2.18	2.36	2.70	2.81
Dividends paid per share of common stock	1.83	1.79	1.75	1.68	1.60
Total assets, end of period[(1)]	$2,970,911	$2,813,120	$2,742,718	$2,614,172	$2,397,890
Total equity[(1)]	751,872	729,627	712,158	691,625	659,283
Long-term debt	681,700	691,700	641,700	591,700	601,700

(1) Prior period balances have been adjusted for a prior period error identified during the first quarter of 2013. See Note 16 for additional detail.

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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, 2013, 2012, and 2011. References in this discussion to "Notes" are 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 which include:

- NW Natural Energy, LLC (NWN Energy),
- NW Natural Gas Storage, LLC (NWN Gas Storage),
- Gill Ranch Storage, LLC (Gill Ranch),
- NNG Financial Corporation (NNG Financial),
- Northwest Energy Corporation (Energy Corp), and
- NW Natural Gas Reserves, LLC (NWN Gas Reserves).

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

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

EXECUTIVE SUMMARY

During 2013 we continued to advance our long-term strategic directives. Highlights for the year include:

- increased customer count with close to 9,000 net customer additions for an annual customer growth rate of 1.3%;
- developed new online tools for customers to compare energy cost and service options;
- ranked number one in J.D. Power customer service survey among large gas utilities in the West;
- pursued gas storage development opportunities at our Mist gas storage facility;
- completed construction of a new operations service center, which also serves as a back-up business continuity center, and industry leading training facility;
- completed construction of a new water treatment station at our Gasco site; and
-

received regulatory approval for an increased spending limit for our annual system integrity cap-ex tracker, which supports our safety investments.

We manage our business and strategic initiatives with a long-term view on providing natural gas service safely and conveniently to our customers, working with regulators on key policy initiatives, and remaining focused on growing our business. See "2014 Outlook" below for more information.

Key financial highlights include:

In millions, except per share data	2013	2012	2011
Consolidated net income	$60.5	$58.8	$63.0
Consolidated EPS	2.24	2.18	2.36
Utility margin	$353.9	$344.5	$343.0

Results for 2013:

- net income and EPS increased primarily due to higher utility margin in 2013 and a one-time tax charge taken in 2012;
- gas storage net income increased primarily due to higher asset management revenues and lower operating costs; and
- utility margin increased primarily due to customer growth and higher rate-base return on our gas reserve and other investments.

See "Consolidated Earnings and Dividends" below for additional detail.

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2014 OUTLOOK

We are focused on the long-term strategic goals for our business: delivering safe and reliable gas to our customers and growing our gas distribution and gas storage businesses. We believe our 2014 outlook leverages our resources and our history of innovative solutions to continue meeting the needs of customers, regulators, and shareholders. We consider the following components critical in achieving these long term goals:

Deliver Gas	Grow Our Businesses
Ensure Safety and Reliability	Grow Customer Base
Advance Regulatory Dockets and Policy	Pursue Key Initiatives
Collaborate on Regulatory Energy Policies	Develop New Services

SAFETY AND RELIABILITY. Delivering natural gas safely and reliably to our customers and providing employees with a safe work environment are our top priorities. During 2014, we will continue ensuring our pipeline system and facilities are well maintained with ongoing facility improvements and additional investments in our system integrity program. We plan to continue removing the bare steel pipe in our system with complete removal targeted by the end of 2015. We are preparing for new regulations from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) that are expected to be issued in 2015 with a projected effective date of 2016.

Reliability of our system and delivering to our customers on design days is a key priority. In 2014, we plan to file our integrated resource plan with the OPUC and WUTC. This plan will help to define the required infrastructure improvements and expansions necessary to provide safe and reliable gas service to our customers.

REGULATION. Proper regulatory policies and support from our regulators helps ensure the utility can continue to effectively deliver gas to customers and earn a reasonable return for shareholders. During 2014, we plan to resolve open dockets from our 2012 Oregon general rate case, which include: a review of the interstate storage sharing arrangement; the implementation of our new SRRM; and the development of appropriate rate treatment for prepaid pension assets in rate base. In addition to these dockets, we plan to work closely with regulators to create an incentive mechanism for gas utilities to reduce greenhouse gas emissions.

ENERGY POLICIES. The Company is strengthened by innovatively addressing the needs of our customers, employees, and the communities we serve in a challenging economic and regulatory environment. In 2014, we will continue to work with state legislators to help build a strong energy plan for Oregon. In addition, we remain committed to working with environmental agencies to make significant progress towards remediation of our legacy environmental sites.

GROW CUSTOMER BASE. In the utility, we continue to leverage our resources to provide natural gas services to our residential, commercial, and industrial customers. We are beginning to see signs of improvement in the housing market and commercial development in our region and are committed to growing our customer base. We plan to investigate ways of potentially expanding the reach of our current distribution system, including development of new self-service online capabilities for builders, contractors, and homeowners. In our gas storage business, we will focus on maximizing the value of our storage capacity and optimizing revenue opportunities as they arise, while recognizing the unique challenges that currently low, seasonally stable natural gas prices bring to the storage market.

We believe that investing in operating efficiencies and marketing opportunities for our core businesses best positions us for growth now and into the future.

KEY INITIATIVES. Increasing gas usage in our region is likely to require additional infrastructure locally as well as through new connections to gas supplies. Our utility operations and gas storage operations at Mist currently depend on a single bi-directional interstate transmission pipeline to transport gas supplies to customers. We continue to work with regulators and utilities in the Pacific Northwest to advance a new integrated, regional cross-Cascades pipeline to create regional diversity and increased reliability for our system. The need for new connections to gas supply increases as additional, potential large electric load generation and industrial projects are sited within the region.

The need for new flexible gas-fired electric generation has been identified in the Pacific Northwest region to integrate intermittent wind resources into the power system. Natural gas complements wind and solar renewable energy options as a reliable, on-call, electric generation resource. We believe natural gas storage for wind following electric generation plants is needed, and we are working on opportunities to expand our Mist storage facility to support an announced gas fired plant being built by Portland General Electric (PGE) at Port Westward, Oregon to follow wind. The Mist expansion project is subject to several conditions, including, but not limited to, PGE's approval of projected costs.

NEW UTILITY SERVICES. We are currently working to provide the infrastructure necessary to support compressed natural gas (CNG) fleets, and are monitoring the new legislation expected during 2014 that may support natural gas projects such as conversions to natural gas, heavy-duty vehicle conversions to CNG, and industrial projects.

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Issues, Challenges and Performance Measures

ECONOMY. The local, national, and global economies showed signs of improvement during 2013. We saw increased utility customer growth and business demand for natural gas. Our utility’s customer growth rate was 1.3% in 2013, compared to growth of 0.9% in 2012 and 0.8% in 2011. The local Oregon economy is beginning to show signs of recovery as unemployment rates in the region dropped from approximately 8% in 2012 to under 7% at the end of 2013. We believe our utility is well positioned for continued customer additions and increasing industrial demand as the economy continues to strengthen because of low, stable natural gas prices, our relatively low market penetration, and our ongoing marketing focus of converting homes and businesses to natural gas. Additional growth may also come with increased industrial load from new projects in the region and proposed legislation that favors lower carbon emissions and lower cost energy alternatives, such as natural gas. Our gas storage business is also impacted by the employment trends throughout the West coast, including California, which was among the hardest hit during the recession, but is experiencing lower unemployment levels in 2013 and improvements in housing prices.

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

Our utility's annual PGA mechanisms in Oregon and Washington, combined with our gas price hedging strategies, enable us to reduce earnings exposure for the Company and secure lower gas costs for our customers. We typically hedge gas prices on 75% of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2013-14 gas year (November 1, 2013 - October 31, 2014) hedged at 75% of our forecasted sales volumes, including 31% in financial swap and option contracts and 44% in physical gas supplies. For further discussion see "Regulatory Matters-Rate Mechanisms-Purchased Gas Adjustment" below.

In addition to the amount hedged for the current gas contract year, we are also hedged at approximately 33% for the 2014-15 gas year as of December 31, 2013 and between 7% and 21% for annual requirements over the following five gas years. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather and economic conditions, and estimated gas reserve production. Also, our storage inventory levels may increase or decrease based on storage expansion, storage contracts with third parties, or storage recall by the utility.

Although less expensive and more stable gas prices provide opportunities to manage costs for our utility customers, they

also present challenges for our gas storage businesses by lowering the price of, and reducing the demand for, storage services. Consequently, our ability to sign storage contracts with customers at favorable prices directly impacts our financial results. Increases in demand for natural gas, or decreases in supplies can put upward pressure on gas prices and gas price volatility. Similarly, decreases in demand and increases in supplies can cause downward pressure on gas prices and gas price volatility. Current storage prices remain low due to current low stable gas prices; as a result, in the short-term we are focused on lowering operating costs and finding opportunities in the market to increase revenues through enhanced services for storage customers.

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

We also recover some of our environmental costs from insurance policies and only seek recovery from customers for amounts not covered by insurance. Ultimate recovery of environmental costs from regulated utility rates will depend on our ability to effectively manage these costs and demonstrate that costs were prudently incurred, and understand the impact of the annual earnings test in Oregon. Environmental cost recovery and carrying charges on amounts charged to Washington customers will be determined in a future proceeding.

CLIMATE CHANGE. We recognize that we are likely to be impacted by future carbon constraints. To address possible constraints, we are seeking clean energy growth opportunities that position us for long-term success in a lower carbon energy economy and to advance our customers' interests in energy conservation, efficiency and environmental stewardship. A variety of federal, state, local and international climate change initiatives, including new regulations, are underway, but we cannot determine the impact of these initiatives at this time. For example, an array of Environmental Protection Agency (EPA) rules impacting coal plants has driven some coal plants to shut down early although the EPA is not mandating coal plant closures. Coal plant shut downs could increase the demand for natural gas as a lower carbon emission fuel and create opportunities for us. Similarly, because natural gas has a relatively low carbon content, it is also possible that future carbon constraints could create additional demand for natural gas for base load electric generation, direct use in homes and businesses, backing up intermittent renewable resources, and as a transportation fuel to displace gasoline and diesel fuels.

As required under EPA greenhouse gas regulations, we annually report our system throughput and unintended

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greenhouse gas releases. While our carbon dioxide equivalent emission levels are relatively small, the adoption and implementation of any regulations imposing reporting obligations, or limiting emissions of greenhouse gases associated with our operations, could result in an increase in the prices we charge our customers or a decline in the demand for natural gas.

PERFORMANCE MEASURES. We measure our performance and monitor progress on relevant metrics including, but not limited to:

- earnings per share growth;
- utility margin;
- ROE; and
- various operational metrics.

CONSOLIDATED EARNINGS AND DIVIDENDS

Consolidated Earnings

Consolidated highlights include:

In millions, except EPS data	2013	2012	2011
Net income	$60.5	$58.8	$63.0
EPS	2.24	2.18	2.36
ROE	8.2 %	8.2 %	9.0 %

2013 COMPARED TO 2012. The primary factors contributing to the $1.8 million increase in consolidated net income were:

- a $9.4 million increase in utility margin primarily due to customer growth and the rate-base return on our gas reserve and other investments; and
- a $2.7 million after-tax charge taken in 2012 from an Oregon general rate case disallowance.

Partially offsetting the above factors were:

- a $7.1 million increase in operations and maintenance expense primarily due to increased utility payroll and system maintenance and safety program costs; and
- a $2.9 million increase in depreciation and amortization expenses primarily due to higher levels of investment in property, plant, and equipment at the utility.

2012 COMPARED TO 2011. The most significant factors contributing to the $4.3 million decrease in consolidated net income were:

- a $4.1 million increase in operations and maintenance expense primarily due to increases in utility payroll and employee benefit costs, utility training costs, and utility expenses related to our Oregon general rate case;
- a $3.0 million increase in depreciation and amortization expenses primarily due to higher levels of investment in property, plant, and equipment at the utility; and
- a $2.7 million after-tax charge to income tax expense related to a regulatory disallowance from the Oregon general rate case.

Partially offsetting the above factors were:

- a $1.6 million increase in utility margin primarily due to a $7.4 million net charge in 2011 results related to a utility tax law change in Oregon as well as residential and commercial customer growth, partially offset by a decrease in margin primarily due to timing differences from the new billing rate structure resulting from the Oregon general rate case and the effects of warmer weather;
-

- a $4.1 million increase in gas storage operating income primarily attributable to revenue increases from additional contracted storage capacity at Gill Ranch, partially offset by $2.8 million increase in interest expense due to the full year impact of Gill Ranch notes; and
- a $0.9 million increase in net income from our other non-utility businesses.

Dividends

Dividend highlights include:

Per common share	2013	2012	2011
Dividends paid	$1.83	$1.79	$1.75

The Board of Directors declared a quarterly dividend on our common stock of 46.0 cents per share, payable on February 14, 2014, reflecting an indicated annual dividend rate of $1.84 per share.

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RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation by the OPUC, WUTC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility. In 2013, approximately 90% of our utility gas volumes and revenues were derived from Oregon customers, with the remaining 10% from Washington customers. Earnings and cash flows from utility operations are largely determined by rates set in general rate cases and other proceedings in Oregon and Washington, but are also affected by the local economies in Oregon and Washington, the pace of customer growth in the residential, commercial, and industrial markets, and our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of our utility-related costs, including operating expenses and investment costs in utility plant and other regulatory assets. See "Most Recent General Rate Cases" below.

GAS STORAGE. Our gas storage businesses are subject to regulation by the OPUC, CPUC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and CPUC also regulate the issuance of securities and system of accounts. The OPUC and FERC regulate intrastate and interstate storage services, respectively, under 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 CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace. In 2013, approximately 56% of our storage revenues were derived from FERC and Oregon regulated operations and approximately 44% 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. In 2008, 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. These customer rates went into effect on January 1, 2009.

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 are effective January 1, 2014, with the rate changes having no significant impact on our revenues.

2013 Regulatory Activities

WORKING GAS INVENTORY SETTLEMENT. On September 30, 2013, the OPUC approved an all-party settlement agreement that allows the Company to include $39.5 million of inventory in rate base and recover $4.5 million in carrying costs. Previously, the Company had been accruing earnings of $4.0 million related to working gas carrying costs for 2013 based on the amount of working gas inventory proposed in our 2012 general rate case. The carrying costs were included in PGA rates beginning November 1, 2013.

GASCO WATER TREATMENT STATION. On October 28, 2013, the OPUC approved placing $19.0 million of capital costs associated with constructing a water treatment station at our Gasco environmental site into rates beginning November 1, 2013. These amounts are subject to refund, with interest, in the event the Commission determines, through a separate docket, that any of these costs were incurred imprudently. On February 13, 2014, NW Natural filed an all-party stipulation in the proceeding with the OPUC, which if approved, would deem Gasco construction costs prudent and would also approve applying $2.5 million of insurance proceeds plus interest to reduce the Gasco costs included in rates beginning November 1, 2014.

SITE REMEDIATION AND RECOVERY MECHANISM (SRRM). In the 2012 Oregon general rate case, this new mechanism was approved to recover the Company's deferred environmental costs. The Commission ordered a separate docket to determine the prudence of deferred costs, the allocation of insurance proceeds, and an earnings test that would be applied to past and future deferred costs. In July 2013, all parties filed a settlement agreement with the OPUC to address how to apply the new mechanism. In November, the Commission rejected the settlement and ordered further proceedings. We have established a schedule for 2014 and are working toward resolving this matter.

INTERSTATE STORAGE SHARING. A docket has been opened to review the current revenue sharing arrangement that allocates a portion of the net revenues generated from non-utility Mist storage services and third-party asset management services to utility customers. We anticipate resolution of this docket in 2014.

PREPAID PENSION ASSETS. The Company requested in its last rate case that prepaid pension assets be included in rate base and allowed a return on the investment. A separate docket was ordered by the OPUC to review the rate treatment of pensions on a general, non-utility-specific basis. This pension docket is currently open and we anticipate resolution in 2014. The OPUC has authorized NW Natural to continue collecting pension expense based on the amounts set in our 2003 Oregon general rate case and to defer into a regulatory balancing account the difference between actual expense and collected expense for future rate recovery. We anticipate resolution of this docket in 2014.

CNG TARIFF APPROVED. In January 2014, we received approval from the OPUC to offer business customers a service to install, own, and maintain gas compression equipment that enables them to fuel their vehicle fleets with CNG. NW Natural filed the tariff in June 2013 after receiving requests from businesses interested in switching or increasing the number of their fleet vehicles fueled by CNG. Costs associated with providing this service will be directly paid by business customers using the service. The OPUC will review the tariff in two years to assess the market for CNG at that time.

Rate Mechanisms

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

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

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20% or 10% of the difference between actual and estimated gas costs, respectively. Under the Washington PGA mechanism, we defer 100% of the higher or lower actual gas costs, and those gas cost differences are normally 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 for refund to customers. Under this provision, if we select the 80% deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90% deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90% deferral option for the 2011-2012, 2012-2013, and 2013-2014 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2011 and 2012, the ROE threshold after adjustment for long-term interest rates was 10.92% for both years. We refunded $0.7 million to customers based on the 2011 utility earnings test, and there were no refunds required based on the 2012 utility earnings test. For calendar year 2013, the ROE threshold was 10.58% with no refund expected to be required based on our results of operations. The 2013 test is expected to be filed in May of 2014.

GAS RESERVES. In 2011 the OPUC approved the Encana gas reserve transaction to provide long-term gas price protection for our utility customers and determined that the Company's costs under the agreement will be recovered, plus a rate base return on our investment, on an ongoing basis through our annual PGA mechanism, including the regulatory deferral and incentive sharing process for the commodity cost of gas. Gas produced from our interests is sold by Encana at then prevailing market prices with revenues from such sales, net of associated production costs, credited to our cost of gas. Annually, a forecast is established for the amounts related to revenues, costs, and production volumes expected, and any variances between forecasted and actual results are subject to our PGA incentive sharing in Oregon.

DECOUPLING. 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 in the Oregon general rate case with the difference between our 2003 baseline consumption and the consumption decided in our 2012 general rate case being calculated within base rates. This employs a use-per-customer decoupling mechanism, 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. Baseline consumption reflects forecasted customer consumption data used in the Oregon general rate case. In Washington, customer use is not covered by such a tariff. See "Business Segments—Local Gas Distribution Utility Operations" below.

WEATHER NORMALIZATION TARIFF. 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, 2013, 8% had opted out. We do not have a weather normalization mechanism approved for residential and commercial Washington customers, which account for about 10% of total customers. See "Business Segments—Local Gas Distribution Utility Operations" below.

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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 under our annual PGA tariff complete the term of their service election.

SYSTEM INTEGRITY PROGRAM (SIP). Since 2002, various laws requiring minimum standards for integrity management programs and SIPs for natural gas transmission and distribution pipelines have been enacted. Most recently, in January 2012 the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law and requires increased civil penalties for pipeline safety violations, improvements in prevention programs for pipelines, and additional review and analysis of various aspects of gas transmission lines. We are working diligently with industry associations and federal and state regulators to ensure our compliance with the provisions of this new law.

The OPUC approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program, our SIP, and for related pipeline safety rules adopted by the U.S. Department of Transportation’s PHMSA. In addition, the OPUC has provided a two-year extension beginning in November 2012 of our capital expenditure tracking mechanism to recover capital costs related to SIP. We record the costs related to the integrity management program as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period, and recover the revenue requirement associated with these costs, subject to audit, through rate changes effective with the Oregon annual PGA. Our SIP costs are tracked into rates annually, with rate base recovery after the first $4 million of capital costs. An annual cap for expenditures has been set at $12 million, but extraordinary costs above the cap may be approved with written consent of the OPUC staff and other interested parties and approval of the OPUC. During 2013, the Commission approved a temporary increase to the annual cap, authorizing an additional $13.7 million of expenditures above the cap over the next two years to be tracked into rates. With the increased cap, we plan to substantially complete our bare steel replacement by the end of 2015, and as a result this stipulation precludes us from tracking any additional bare steel replacement costs into rates after 2015. We do not have any special accounting or rate treatment for our SIP costs incurred in the state of Washington.

ENVIRONMENTAL COST DEFERRAL. The OPUC has authorized the deferral of environmental costs associated with certain named sites and to accrue carrying costs on amounts deferred, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the OPUC has authorized us to defer environmental costs and accrued carrying costs through January 2014. We filed a request with the OPUC in January 2014 to continue our deferral of costs through January 2015. See Note 15 and 17 for further discussion of our

regulatory and insurance recovery of environmental costs and "2013 Regulatory Activities" above for information regarding SRRM.

The WUTC also authorized the deferral of environmental costs, if any, that are appropriately allocated to Washington customers. This order was effective January 26, 2011 with cost recovery and a carrying charge to be determined in a future proceeding.

PENSION COST DEFERRAL. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility’s authorized rate of return, which is currently 7.78%. Future years’ deferrals will depend on changes in plan assets and projected benefit liabilities based on a number of key assumptions, and our pension contributions. Pension expense deferrals were $9.1 million and $7.9 million in 2013 and 2012, respectively. See "Application of Critical Accounting Policies and Estimates", below. As noted above, the Company continues to seek rate treatment for amounts invested in prepaid pension assets.

CUSTOMER CREDITS FOR GAS STORAGE SHARING. On an annual basis, we credit amounts to Oregon and Washington customers as part of our regulatory incentive sharing mechanism related to revenues from gas storage and asset management of pipeline capacity and gas storage at Mist. Generally amounts are credited to Oregon customers in June, while credits are given to customers in Washington through reductions in rates in the annual PGA filing in November. See "Business Segments—Gas Storage" below.

following table presents the credits to customers:

In millions	2013	2012	2011
Oregon utility customer credit	$8.8	$9.2	$12.5
Washington utility customer credit	0.5	0.8	0.9

Business Segments - Local Gas Distribution Utility Operations

Our utility margin results are largely affected by customer growth and, to a certain extent, by changes in volume due to weather and customers' gas usage patterns. In Oregon, we have a conservation tariff, which adjusts utility margin up or down through deferred accounting to offset changes resulting from increases or decreases in average use by residential and commercial customers. We also have a weather normalization tariff in Oregon, which adjusts customer bills up or down to offset changes in utility margin resulting from above- or below-average temperatures during the winter heating season. Both mechanisms are designed to reduce the volatility of our utility's earnings and customer charges. See "Regulatory Matters—Rate Mechanisms" above.

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Utility segment highlights include:

Dollars and therms in millions, except EPS data	2013	2012	2011
Utility net income	$54.9	$54.0	$59.7
EPS - utility segment	$2.03	$2.01	$2.23
Gas sold and delivered (in therms)	1,146	1,112	1,152
Utility margin(1)	$353.9	$344.5	$343.0

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

2013 COMPARED TO 2012. The primary factors contributing to the $0.9 million or $0.02 per share increase in net income were as follows:

- a $9.4 million net increase in utility margin primarily due to:
  - a $10.8 million increase related to customer growth and the rate-base return on our gas reserve and other investments, such as our pipeline integrity tracker; and
  - a $3.9 million increase related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 Oregon general rate case. As a result of changes to the decoupling baseline for average use per customer included in the 2012 rate case, the decoupling mechanism's results this year will not be comparable to last year, although the overall impact on revenues will generally be the same on an annualized basis.

  These increases in margin were partially offset by:
  - a $3.9 million decrease in gains from gas cost incentive sharing due to actual gas prices that were roughly equivalent to estimated PGA prices for the current year as compared to actual gas prices that were lower than estimated PGA prices for the prior year; and
  - a $1.4 million decrease primarily related to the lower Oregon Authorized ROE of 9.5% from the 2012 general rate case.
- a $1.5 million increase in other income and expense, net primarily due to interest on higher average regulatory account balances; and
- a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance. See "Application of Critical Accounting Policies and Estimates—Regulatory Accounting" below.

These factors were partially offset by:

- a $7.4 increase in operations and maintenance expense primarily due to increased utility payroll and system maintenance and safety program costs;
- a $2.9 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment; and
- a $2.4 million increase in interest expense primarily due to increases in long-term debt outstanding.

Total utility volumes sold and delivered in 2013 increased 3.1% over last year primarily due to the impact of colder weather on residential and commercial use.

2012 COMPARED TO 2011. The primary factors contributing to the $5.6 million or $0.22 per share decrease in net income were as follows:

- an $8.4 million increase in operating expenses, excluding cost of gas, primarily due to higher operations and maintenance expense and depreciation and amortization expense; and
- a $2.7 million one-time tax charge related to the Oregon general rate case. See "Application of Critical Accounting Policies and Estimates—Regulatory Accounting" below.

These factors were partially offset by:

- a $1.6 million net increase in utility margin primarily due to:
  - a $7.4 million one-time, pre-tax charge in 2011 related to the repeal of Senate Bill (SB) 408, which did not reoccur in 2012;
  - a 0.9% increase in customers over last year;
  - a $3.4 million increase from the allowed return on our gas reserves investment;
  - a $2.5 million increase in other margin adjustments; and
  - a $1.7 million increase in contribution from our gas cost incentive sharing mechanism.

  These increases in margin were partially offset by a $9.3 million decrease in our residential and commercial margin primarily reflecting:
  - a $3.9 million decrease due to timing differences from the new billing rate structure resulting from the Oregon general rate case;
  - an $8.4 million decrease due to weather from the following three items: (1) positive margin impact realized in the second quarter of 2011 when colder weather was not fully offset by our Oregon weather normalization mechanism, (2) warmer weather during 2012 in Washington, which does not have normalization mechanisms in place, and (3) the effect of warmer weather on margin for Oregon customers that opt out of weather normalization; and
  - a $0.5 million decrease in operating revenues primarily due to rate case impacts including a decrease in our authorized ROE.
- a $1.5 million decrease in utility interest expense due to lower interest rates on both short-term and long-term debt balances.
- a $3.5 million decrease, excluding the $2.7 million one-time tax charge mentioned above, in income taxes due to lower pre-tax utility income.

Total utility volumes sold and delivered in 2012 decreased 3.5% over last year primarily due to the impact of warmer weather on residential and commercial use.

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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	2013	2012	2011	Favorable/(Unfavorable) 2013 vs. 2012	2012 vs. 2011
Utility volumes (therms):					
Residential and commercial sales	671,906	637,885	681,621	34,021	(43,736)
Industrial sales and transportation	474,525	473,884	470,733	641	3,151
Total utility volumes sold and delivered	1,146,431	1,111,769	1,152,354	34,662	(40,585)
Utility operating revenues:					
Residential and commercial sales	$673,250	$642,337	$744,355	$30,913	$(102,018)
Industrial sales and transportation	68,880	70,020	81,313	(1,140)	(11,293)
Regulatory adjustment for income taxes paid[1]	—	—	(7,162)	—	7,162
Other revenues	4,054	5,935	3,713	(1,881)	2,222
Less: Revenue taxes	19,002	18,430	20,741	572	(2,311)
Total utility operating revenues	727,182	699,862	801,478	27,320	(101,616)
Less: Cost of gas	373,298	355,335	458,508	17,963	(103,173)
Utility margin	$353,884	$344,527	$342,970	$9,357	$1,557
Utility margin:[2]					
Residential and commercial sales	$321,608	$306,382	$315,688	$15,226	$(9,306)
Industrial sales and transportation	28,335	28,586	28,635	(251)	(49)
Miscellaneous revenues	4,308	4,452	4,875	(144)	(423)
Gain (loss) from gas cost incentive sharing	(41)	3,811	2,107	(3,852)	1,704
Other margin adjustments	(326)	1,296	(1,173)	(1,622)	2,469
Regulatory adjustment for income taxes paid[1]	—	—	(7,162)	—	7,162
Utility margin	$353,884	$344,527	$342,970	$9,357	$1,557
Customers - end of period:					
Residential customers	628,634	621,399	615,670	7,235	5,729
Commercial customers	65,321	63,619	62,948	1,702	671
Industrial customers	918	923	925	(5)	(2)
Total number of customers	694,873	685,941	679,543	8,932	6,398
Actual degree days	4,379	4,152	4,652		
Percent colder (warmer) than average weather[3]	3%	(3)%	9%		

(1) See "Regulatory Adjustment for Income Taxes Paid" below for additional information.

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

(3) Average weather represents the 25-year average degree days, as determined in our Oregon general rate case. For 2013, average weather represents the 25-year average degree days as set in our 2012 Oregon general rate case. For 2012, average weather represents degree days based on the 25-year average set in our 2003 Oregon general rate for the months of January through October, plus the 25-year average set in the 2012 Oregon general rate case for the months of November and December. For 2011, average weather represents the 25-year average degree days as set in the 2003 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 Tariff" above.

Residential and commercial sales highlights include:

In millions	2013	2012	2011
Volumes (therms):			
Residential sales	418.6	395.5	424.9
Commercial sales	253.3	242.4	256.7
Total volumes	671.9	637.9	681.6
Operating revenues:			
Residential sales	$447.4	$428.5	$497.2
Commercial sales	225.9	213.8	247.2
Total operating revenues	$673.3	$642.3	$744.4
Utility margin:			
Residential:			
Sales	$234.1	$211.6	$222.5
Weather normalization	(9.0)	(0.1)	(10.2)
Decoupling	2.6	8.6	16.7
Total residential utility margin	227.7	220.1	229.0
Commercial:			
Sales	92.1	84.0	87.0
Weather normalization	(4.0)	0.2	(2.9)
Decoupling	5.8	2.1	2.6
Total commercial utility margin	93.9	86.3	86.7
Total utility margin	$321.6	$306.4	$315.7

2013 COMPARED TO 2012. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 34.0 million therms, or 5%, primarily reflecting 5% colder weather and customer growth;
- operating revenues increased $30.9 million, or 5%, due to a 5% increase in sales volumes and $36.2 million of credits from gas cost savings which were applied to customer billings in 2012, partially offset by an 9% decrease in average gas prices, which flowed through the Company's PGA rates; and
- utility margin increased $15.2 million, or 5%, primarily reflecting the following:

a $10.8 million increase related to customer growth and the rate-base return on our gas reserve and other investments; and

a $3.9 million increase related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 Oregon general rate case.

Partially offsetting these increases was a $1.4 million decrease primarily related to the lower Oregon Authorized ROE of 9.5% from the 2012 general rate case.

2012 COMPARED TO 2011. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes decreased 43.7 million therms, or 6%, primarily reflecting 11% warmer weather;
- operating revenues decreased $102.0 million, or 14%, due to a 6% decrease in sales volumes, a 7% decrease in average gas prices, which flowed through the Company's PGA rates, and $36.2 million of credits on customers’ bills in 2012 related to the refund of gas cost savings; and
- utility margin decreased $9.3 million, or 3%, primarily reflecting the following:
  - a $3.9 million decrease due to timing differences from the new billing rate structure resulting from the Oregon general rate case;
  - an $8.4 million decrease due to the following weather impacts: (1) a $3.0 million of positive margin impact realized in the second quarter of 2011 when colder weather was not fully offset by our Oregon weather normalization mechanism, (2) a $3.2 million decrease due to warmer weather in Washington, which does not have normalization mechanisms in place, and (3) a $2.2 million decrease due to the effect of warmer weather on margin for Oregon customers that opt out of weather normalization;
  - a $0.5 million decrease in operating revenues primarily due to rate case impacts including a decrease in our authorized ROE; and
  - a $3.4 million margin increase from our gas reserves investment.

Industrial Sales and Transportation

Operating revenues from industrial customers include the commodity cost component of gas sold under sales service but not under transportation service. Therefore, operating revenues from industrial customers can increase or decrease when customers switch between sales service and transportation service, but generally our margins from these customers are unaffected by these changes because we do not typically include a profit mark-up for the cost of gas. As such, we believe volumes delivered and margins are better measures of performance for the industrial sector.

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Industrial sales and transportation highlights include:

In millions	2013	2012	2011
Volumes (therms):			
Industrial - firm sales	34.3	34.9	37.6
Industrial - firm transportation	144.5	131.2	133.0
Industrial - interruptible sales	59.5	59.6	59.1
Industrial - interruptible transportation	236.2	248.2	241.0
Total volumes	474.5	473.9	470.7
Utility margin:			
Industrial - sales and transportation	$28.3	$28.6	$28.6

2013 COMPARED TO 2012. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales volumes remained relatively flat for 2013 compared to 2012; and
- utility margin decreased 1%, primarily due to lower demand from customers in the pulp and paper segment. These decreases were partially offset by contributions from new customers and added load from existing customers.

2012 COMPARED TO 2011. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales volumes increased 3.2 million therms, or 1%, primarily reflecting the impact of customers switching to natural gas due to the lower prices of natural gas compared to oil; and
- utility margin remained flat primarily reflecting the loss of a few large industrial customers in 2011 due to the economy. Partially offsetting this decrease was an increase in customers switching to natural gas throughout 2012 due to its price advantage.

Regulatory Adjustment for Income Taxes Paid

Oregon Senate Bill (SB) 408 was in effect from 2007 through 2010 and was a regulatory mechanism for truing up income taxes paid. In May 2011, SB 967 effectively repealed the SB 408 regulatory adjustment for income taxes paid for the 2010 tax year and all years thereafter. Due to the repeal, the Company recorded a $7.4 million write-off including interest in 2011. For additional information, see "Application of Critical Accounting Policies and Estimates—Revenue Recognition" below.

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 current or future revenues from residential, commercial and industrial firm customers.

Other revenue highlights include:

In millions	2013	2012	2011
Other operating revenues	$4.1	$5.9	$3.7

2013 COMPARED TO 2012. The primary factors contributing to changes in other revenues were as follows:

- other revenues decreased $1.9 million primarily due to a positive 2012 regulatory adjustment which did not reoccur in 2013.

2012 COMPARED TO 2011. The primary factors contributing to changes in other revenues were as follows:

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other revenues increased $2.2 million primarily due to a net increase in revenues from various regulatory adjustments of approximately $2.7 million, partially offset by a decrease of $0.4 million of miscellaneous fee income.

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

We use natural gas commodity hedge contracts (derivative instruments), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage gas price stability. Gains and losses from these financial hedge contracts are generally included in our PGA and normally do not impact net income because the hedged prices are reflected in our annual PGA rates, subject to a regulatory prudence review. However, hedge contracts entered into after the annual PGA rates are set for Oregon customers can impact net income because we would be required to share in any gains or losses as compared to the corresponding commodity prices built into rates in the PGA. In Washington, 100% of the actual gas costs, including hedge gains and losses allocated to Washington gas sales, are passed through in customer rates. See "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities" below, "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" above, and Note 13.

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Cost of gas highlights include:

Dollars and therms in millions	2013	2012	2011
Cost of gas	$373.3	$355.3	$458.5
Total volumes sold and delivered (therms)	1,146	1,112	1,152
Average cost of gas (cents per therm)	$0.49	$0.54	$0.59
Gain from gas cost incentive sharing	—	3.8	2.1

2013 COMPARED TO 2012. The primary factors contributing to changes in cost of gas were as follows:

- cost of gas increased $18.0 million, or 5%, including the $37.7 million of credits applied to customer billings in 2012 related to the refund of gas cost savings. Excluding the customer credits, total cost of gas decreased $19.7 million, or 5%, primarily due to a 3% increase in volumes offset by an 9% decrease in average cost of gas collected through rates, reflecting lower market prices for natural gas.

2012 COMPARED TO 2011. The primary factors contributing to changes in cost of gas were as follows:

- cost of gas decreased $103.2 million, or 23%, including the $37.7 million of credits applied to customer billings in 2012 related to the refund of gas cost savings. Excluding the customer credits, total cost of gas decreased $65.5 million, or 14%, primarily reflecting lower usage due to 11% warmer weather and PGA rate decreases in 2012 and 2011; and
- average cost of gas collected through rates decreased 5 cents per therm, primarily reflecting lower gas prices that were passed on to customers through PGA rate decreases effective November 1, 2011 and 2012.

The effect on net income from our gas cost incentive sharing mechanism was a pre-tax loss in margin of less than $0.1 million in 2013 compared to a pre-tax gain in margin of $3.8 million in 2012 and $2.1 million in 2011. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" above.

Business Segments - Gas Storage

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

At Mist, we provide gas storage services to customers in the interstate and intrastate markets primarily 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 businesses segment. Pre-tax income from gas storage at Mist and asset management services using our utility's storage or transportation capacity is subject to revenue sharing with core utility customers. Under this regulatory incentive sharing mechanism in Oregon, we retain 80% of pre-tax income

from Mist gas storage services and from 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. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage and asset management services.

Our 75% undivided ownership interest in the Gill Ranch facility is held by our wholly-owned subsidiary Gill Ranch, which is also the operator of the facility. Our portion of the facility is currently providing 15 Bcf of gas storage capacity. Gill Ranch commenced operations at the end of 2010, with the first full storage injection season beginning on April 1, 2011. We also contract with an independent energy marketing company to manage the value of our storage assets at Gill Ranch. See Note 4.

Gas storage segment highlights include:

In millions, except EPS data	2013	2012	2011
Gas storage net income	$5.6	$4.5	$4.1
EPS - gas storage segment	0.21	0.17	0.15
Average gas storage contracted capacity (Bcf)	21	21	16

2013 COMPARED TO 2012. Our gas storage segment net income increased $1.0 million primarily due to higher revenues from asset management services and lower operating costs.

2012 COMPARED TO 2011. Our gas storage segment net income increased $0.4 million primarily due to revenue increases at Gill Ranch from additional contracted storage capacity. This increase was partially offset by a full year of interest expense from Gill Ranch's senior secured debt, which was issued in November 2011.

For the 2013-2014 gas storage year we are fully contracted at Gill Ranch and at Mist. We are in the process of contracting for the upcoming 2014-2015 gas storage year, which begins in April 2014. The market outlook for gas storage in 2014 remains challenging. In recent months, the country has seen significant storage withdrawals and gas price volatility due to the extreme cold weather nationally, but current storage values have been negatively impacted by the increase in spring and summer prices as they are similar to winter prices, thus reducing the desirability of purchasing gas. As a result we anticipate contracting for the upcoming storage year at lower market prices than in previous periods, especially at our California facility where some multi-year contracts are expiring. See, "Financial Condition—Liquidity and Capital Resources" for more information.

Other

Other primarily consists of NNG Financial's equity investment in KB Pipeline, an equity investment in PGH, which in turn has invested in a cross-Cascades pipeline project, and other miscellaneous non-utility investments and

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business activities. See Note 4 and Note 12 for further details on other activities and our investment in PGH.

Other highlights include:

In millions, except EPS data	2013	2012	2011
Other net income (loss)	$—	$0.2	$(0.7)
EPS - other	—	—	(0.02)

2013 COMPARED TO 2012. Other remained relatively flat over 2013 compared to 2012, as anticipated.

2012 COMPARED TO 2011. Other net income increased $0.9 million as our investment in PGH had a $1.3 million impairment charge in 2011, which did not reoccur in 2012.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

In millions	2013	2012	2011
Operations and maintenance	$136.6	$129.5	$125.4

2013 COMPARED TO 2012. Operations and maintenance expense increased $7.1 million or 6% in 2013 compared to 2012. The following summarizes the major factors that contributed to this increase:

- a $5.9 million increase in utility payroll expense primarily related to additional customer service positions for new programs and higher incentive compensation; and
- a $2.7 million increase in utility expenses related to system maintenance and safety program costs.

Partially offsetting the above factors were:

- a $0.9 million decrease in utility bad debt expense. See further discussion below.

2012 COMPARED TO 2011. Operations and maintenance expense increased $4.1 million or 3% in 2012 compared to 2011. The following summarizes the major factors that contributed to this increase:

- a $3.7 million increase in utility payroll expense primarily related to an increase in field service employees;
- a $1.7 million increase in utility non-payroll expense including higher costs for new employee training, expenses related to the Oregon general rate case, higher costs for information technology system maintenance and other general customer service cost increases; and
- a $0.9 million increase in utility employee benefit expense, principally related to health care and pension costs, which were driven by an increase in employee count. See below for additional discussion on pension costs.

Partially offsetting the above factors were:

- a $1.1 million reduction in gas storage general and administrative expense primarily reflecting lower costs compared to 2011 when Gill Ranch incurred higher start-up costs; and

- a $0.8 million decrease in utility bad debt expense.

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

Our accounting expense for pension costs increased in 2013 largely due to lower discount rates; however, the OPUC approved a deferral of our utility pension costs for amounts in excess of what is currently recovered in customer rates.

The pension cost deferral is recorded to a regulatory balancing account, which reduces operations and maintenance expense. For the year ended December 31, 2013 and 2012, we deferred pension expenses totaling $9.1 million and $7.9 million, respectively. See Note 8. As a result, increased pension costs had a minimal effect on operations and maintenance expense in 2013 and 2012, with the increase principally related to the cost allocation to our Washington operations, which are not covered by the pension balancing account. For further explanation of the pension balancing account, see "Regulatory Matters—Rate Mechanisms—Pension Deferral" above.

General Taxes

General taxes principally consist of property and payroll taxes and regulatory fees.

General tax highlights include:

In millions	2013	2012	2011
General taxes	$30.0	$30.6	$29.3

2013 COMPARED TO 2012. General taxes remained relatively flat for 2013 compared to 2012, as anticipated.

2012 COMPARED TO 2011. General taxes increased $1.3 million or 4% in 2012 compared to 2011 primarily due to a $0.7 increase in property taxes at Gill Ranch, which reflect increased capital investments added to assessed property tax values during 2012, as well as a $0.4 increase in payroll tax expense at the utility.

Depreciation and Amortization

Depreciation and amortization highlights include:

In millions	2013	2012	2011
Depreciation and amortization	$75.9	$73.0	$70.0

2013 COMPARED TO 2012. Depreciation and amortization expense for 2013 increased by $2.9 million compared to 2012 due to an increase in utility depreciation expense on investments in utility plant for system improvements and training facilities.

2012 COMPARED TO 2011. Depreciation and amortization expense for 2012 increased by $3.0 million compared to 2011 primarily due to a $2.7 million increase in investments in utility plant for system improvements and training facilities.

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Other Income and Expense, Net

Other income and expense, net highlights include:

In millions	2013	2012	2011
Gains from company-owned life insurance	$2.5	$2.3	$2.2
Interest income	0.1	0.2	0.1
Gain on sale of investments	—	(0.2)	(0.1)
Income (loss) from equity investments	(0.1)	—	(1.6)
Net interest on deferred regulatory accounts[1]	4.5	3.0	4.6
Other non-operating	(2.3)	(2.1)	(2.1)
Total other income and expense, net	$4.7	$3.2	$3.1

[1] Prior period balances have been adjusted for a prior period error identified during the first quarter of 2013. See Note 16 for additional detail.

2013 COMPARED TO 2012. Other income and expense, net increased $1.5 million in 2013 primarily due to interest on higher average regulatory account balances.

2012 COMPARED TO 2011. Other income and expense, net remained relatively flat for 2012 compared to 2011.

Interest Expense, Net

Interest expense, net highlights include:

In millions	2013	2012	2011
Interest expense, net	$45.2	$43.2	$42.1

2013 COMPARED TO 2012. Interest expense, net of amounts capitalized, increased $2.0 million in 2013 primarily due to an increase of $2.3 million at the utility from the issuance of long-term debt. The utility issued $50 million of debt with a coupon rate of 3.542% in August 2013 and $50 million of debt with a coupon rate of 4.00% in October 2012. This increase was partially offset by a $0.7 million reduction in 2013 interest expense at the utility from the retirement of $40 million of long-term debt with a coupon rate of 7.13% in 2012. See Note 7 for further detail.

2012 COMPARED TO 2011. Interest expense, net of amounts capitalized, in 2012 increased $1.1 million primarily due to a $2.8 million increase in interest expense at Gill Ranch from the issuance of $40 million of subsidiary senior secured debt in November 2011, partially offset by a $1.5 million decrease in interest expense at the utility due to lower interest rates on new short-term and long-term debt issuances.

Interest expense also reflects a lower average interest rate used in calculating the allowance for funds used during construction (AFUDC). AFUDC rates, consists of short-term and long-term capital costs as appropriate, were 0.3% in both 2013 and 2012, and 0.5% in 2011.

Income Tax Expense

Income tax expense highlights include:

In millions	2013	2012	2011
Income tax expense	$41.7	$43.4	$42.8
Effective tax rate	40.8 %	42.5 %	40.5 %

2013 COMPARED TO 2012. The decrease in income tax expense of $1.7 million or 4% was primarily due to a $2.7 million one-time tax charge taken in 2012 from an Oregon general rate case disallowance.

2012 COMPARED TO 2011. The increase in income tax expense of $0.6 million or 1% was primarily due to a one-time $2.7 million tax charge related to the 2012 Oregon general rate case. This increase in taxes was partially offset by lower pre-tax consolidated earnings.

EFFECTIVE TAX RATES. The effective tax rate in 2013 was lower due to the tax charge taken in 2012 but consistent with expectations and historical rates. The higher effective tax rate in 2012 was primarily due to the $2.7 million tax charge related to the Oregon general rate case. For more information on our income taxes, including a reconciliation between the statutory federal and state income tax rates and the effective tax rate, see Note 2 and Note 9.

FINANCIAL CONDITION

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45% to 50% common stock equity and 50% to 55% long-term and short-term debt. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt retirements and short-term commercial paper maturities. See "Liquidity and Capital Resources" below and Note 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,			
	2013		2012	
Common stock equity	44.7	%	45.3	%
Long-term debt	40.5		42.9	
Short-term debt, including current maturities of long-term debt	14.8		11.8	
Total	100.0	%	100.0	%

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Liquidity and Capital Resources

At December 31, 2013, we had $9.5 million of cash and cash equivalents compared to $8.9 million at December 31, 2012. We also had $4.0 million in restricted cash at Gill Ranch as of December 31, 2013 and 2012, which is being held as collateral for its long-term debt outstanding. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances and add short-term borrowing capacity. In addition, we may also pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC. Our use of retained earnings is not subject to those same restrictions.

For the utility segment, the short-term borrowing requirements typically peak during colder months when the utility borrows money to cover the lag between when it purchases natural gas and when customers pay for the gas. Our short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, borrowings from multi-year credit facilities, cash available from surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use utility long-term debt proceeds to finance utility capital expenditures, refinance maturing debt of the utility and provide for general corporate purposes of the utility.

Market conditions have improved over the past few years as reflected by tighter credit spreads and increased access to financing for investment grade issuers. Based on our current debt ratings (see "Credit Ratings" below), we have been able to issue commercial paper and long-term debt at attractive rates and have not needed to borrow from our back-up credit facility. In the event that we are not able to issue new debt due to adverse market conditions or other reasons, we expect that our near term liquidity needs can be met using internal cash flows or, for the utility segment, drawing upon our committed credit facility. We also have a universal shelf registration filed with the SEC for the issuance of secured and unsecured debt or equity securities, subject to market conditions and certain regulatory approvals. As of December 31, 2013, we have Board authorization to issue up to $325 million of additional first mortgage bonds. We currently have OPUC approval to issue up to $25 million of additional long-term debt for approved purposes. We plan to file an application with the OPUC in early 2014 to increase our OPUC long-term debt authorization to $325 million.

In the event that 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 form of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings. However, based upon current financial swap and option contracts outstanding, we do not have any collateral demand exposure as the Company had unrealized gains of $5.4 million at December 31, 2013.

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

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

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

Regarding federal income tax liabilities, extensions were granted allowing us to take 100% bonus depreciation on qualified expenditures during 2011 and 50% bonus depreciation on a majority of our capital expenditures in 2012 and 2013, which significantly reduced our tax liability for those tax years and is expected to provide cash flow benefits in subsequent years.

Concerning environmental expenditures, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through our insurance settlements and utility rates. The amount and timing of these expenditures is uncertain with additional insurance recoveries expected in 2014. See Note 15, Note 17, and "Results of Operations—Regulatory Matters—Environmental Costs".

The Company did not issue any one-time refunds or credits to customers from gas cost savings in 2013. In 2012, due to significantly lower gas prices from November 2011 to March 2012, the Company was able to provide $35 million of credits to its Oregon utility customers' bills and $4 million in credits to its Washington customers. See "Results of Operations—Regulatory Matters—Regulatory Mechanisms—Purchased Gas Adjustment and —Customer Credits for Gas Cost Incentive Sharing" above. In addition, the Company may also provide its Oregon utility customers with interstate storage credits from the regulatory incentive sharing mechanism related to gas storage and asset management services. See "Results of Operations—

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Regulatory Matters—Regulatory Mechanisms—Customer Credits for Gas Storage Sharing" above.

Short-term liquidity for our gas storage segment is supported by cash balances, internal cash flow from operations, external financing, and, to a certain extent, equity investments from its parent company. Gill Ranch has limited operational history, with operations commencing in October 2010. The abundant supply of natural gas, low volatility of natural gas prices, and available gas storage capacity in California have resulted in lower storage market prices than we have seen in previous years. As a result, we are anticipating lower estimated future earnings and cash flows for Gill Ranch. The amount and timing of these cash flows from year to year are uncertain as the majority of Gill Ranch's storage contracts are short-term. While we expect short-term storage prices to be challenging, we do not anticipate material changes in our sources of short-term liquidity and anticipate our operating cash flows will be sufficient.

In November 2011, Gill Ranch issued $40 million of senior secured debt, with a fixed interest rate on $20 million and a variable interest rate on the remaining $20 million. The average combined interest rate on the debt was 7.38% per annum through December 31, 2013. This debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural and other entities of the consolidated group. The maturity date of the debt is November 30, 2016.

Under the debt agreements, Gill Ranch is subject to certain covenants and restrictions, including but not limited to a financial covenant that requires Gill Ranch to maintain minimum adjusted EBITDA at various levels over the term of the debt. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the agreements, Gill Ranch is also subject to a debt service reserve requirement of 10% of the outstanding principal amount, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on the incurrence of additional debt. At December 31, 2013, we were in compliance with all covenants and restrictions under the debt agreements.

Based on several factors, we believe our Company's 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, 2013 by maturity and type of obligation:

	Payments Due in Years Ending December 31,						
In millions	2014	2015	2016	2017	2018	Thereafter	Total
Commercial paper	$188.2	$—	$—	$—	$—	$—	$188.2
Long-term debt maturities	60.0	40.0	65.0	40.0	22.0	514.7	741.7
Interest on long-term debt	41.8	40.3	37.3	32.1	29.2	271.3	452.0
Postretirement benefit payments(1)	21.9	22.5	23.3	24.1	25.0	148.7	265.5
Capital leases	0.5	0.2	0.1	—	—	—	0.8
Operating leases	5.6	5.5	5.5	5.5	2.9	34.9	59.9
Gas purchases(2)	60.7	—	—	—	—	—	60.7
Gas pipeline capacity commitments	98.7	77.4	66.1	52.1	42.3	217.0	553.6
Gas reserves(3)	49.2	41.8	—	—	—	—	91.0
Other purchase commitments(4)	0.5	0.1	—	—	—	13.6	14.2
Other long-term liabilities(5)	15.2	—	—	—	—	—	15.2
Total	$542.3	$227.8	$197.3	$153.8	$121.4	$1,200.2	$2,442.8

(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 the Company withdrawing from the plan in December 2013. See Note 8.

(2) Gas purchases include contracts which use price formulas tied to monthly index prices, plus hedged derivative liabilities. Commitment amounts are based on futures prices as of December 31, 2013. For a summary of derivatives, see Note 13. For a summary of gas purchase and gas pipeline capacity commitments, see Note 14.

(3) Gas reserves payments reflect contractual obligations to invest in additional gas reserves under our agreements. The contracts for such reserves include termination provisions, under which investments in additional reserves would not be required, if conditions for such provisions were met. We have assumed no cancellation for disclosure of gas reserve commitments.

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

(5) 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, 2013, 612 of our utility employees were members of the Office and Professional Employees International Union (OPEIU) Local No. 11. In July 2009, these union employees and the Company agreed to a five-year labor agreement called the Joint Accord. The 2009 Joint Accord provides for a 1% automatic wage increase each year, plus the potential for up to an additional 2% based on wage inflation and other factors. It also provides competitive health benefits while limiting the cost increases for these benefits to the same level as the annual wage increases. The 2009 Joint Accord extends to May 31, 2014. In 2013, each party served notice of intent to negotiate the terms of an agreement prior to the May 31, 2014 expiration date. We are currently engaged in negotiations to meet this schedule.

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas purchases and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities. See "Credit Agreements" below. At December 31, 2013 and 2012, our utility had commercial paper outstanding of $188.2 million and $190.3 million, respectively. The effective interest rate on the utility’s commercial paper outstanding at December 31, 2013 and 2012 was 0.3%.

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Credit Agreements

In December 2012, we entered into a new multi-year credit agreement for unsecured revolving loans totaling $300 million and an available extension of commitments for two additional one-year periods, subject to lender approval. In December 2013, we extended our commitment for an additional year with an updated maturity date of December 20, 2018. All lenders under the new agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2013 as follows:

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

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

Our credit agreement allows us to request increases in the total commitment amount, up to a maximum of $450 million. The agreement also permits the issuance of letters of credit in an aggregate amount of up to $200 million. Any principal and unpaid interest amounts owed on borrowings under the credit agreements is due and payable on or before the maturity date. There were no outstanding balances under this or our prior credit agreement at December 31, 2013 or 2012. 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, 2013 and 2012, with consolidated indebtedness to total capitalization ratios of 55.3% and 54.7%, respectively.

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

Credit Ratings

Our credit ratings are a factor in our liquidity, 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. In February 2014, Moody's revised our ratings outlook from negative to stable. The following table summarizes our current debt ratings from S&P and Moody’s:

	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 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.

Retirements of Long-Term Debt

The following FMBs were retired:

	Years Ended December 31,		
In millions	2013	2012	2011
Company First Mortgage Bonds			
6.665% Series B due 2011	$—	$—	$10
7.13% Series B due 2012	—	40	—
	$—	$40	$10

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Cash Flows

Operating Activities

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

Operating activity highlights include:

In millions	2013	2012	2011
Cash provided by operating activities	$176.4	$168.8	$233.5

2013 COMPARED TO 2012. The significant factors contributing to the $7.6 million increase in operating cash flows were as follows:

- an increase of $15.8 million in other, net primarily due to inflows from changes in net regulatory balances offset by a decrease in pension liabilities;
- an increase of $12.4 million from net changes in gas cost balances, which primarily reflects $39 million in credits refunded to customers in 2012;
- an increase of $11.8 million due to lower cash contributions to qualified defined benefit pension plans as a result of new IRS funding rules, commonly referred to as MAP-21;
- an increase of $8.0 million from changes in accounts payable balances; and
- an increase of $4.7 million due to changes in the amortization of gas reserves balance.

Partially offsetting these increases was:

- a decrease of $48.3 million from changes in the accounts receivable balance, primarily due to customer growth and 29% colder weather in December 2013.

During the year ended December 31, 2013, we contributed $11.7 million to our utility's qualified defined benefit pension plans, which was significantly higher than the $5.7 million in non-cash expense recognized on the income statement. In 2012, we contributed $23.5 million and had $5.4 million in non-cash expense. We expect pension contributions to exceed non-cash expense for the next few years, but contribution amounts will be less than previously anticipated due to the new federal funding requirements under MAP-21. The amounts and timing of future contributions will depend on market interest rates and investment returns on the plans' assets. See Note 8.

Also significantly affecting cash flows over the past few years has been income tax relief, including the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (2010 Act) and American Taxpayer Relief Act of 2012 (2012 Act). The 2010 Act allowed 100% bonus depreciation on qualified property placed in service between September 9, 2010 and December 31, 2011, and also extended the 50% bonus depreciation deduction to qualifying property placed in service during 2012. The 2012 Act extended 50% bonus depreciation through 2013 for modified accelerated cost recovery system (MACRS) property with a recovery period of 20 years or less. These and other tax benefits resulted in a net operating loss for 2010, which was carried back to the tax year 2009 and resulted in a federal income tax refund of $22.3 million received in 2011 and an additional $2.1 million received in

2012. We generated taxable income in 2011 that was fully offset by the net operating loss (NOL) carried forward from 2010. We generated NOL carryforwards during 2012 and 2013. As of December 31, 2013, we had an estimated federal income tax receivable balance of $3.2 million and an estimated NOL carryforward balance of $113.0 million. In 2011, Oregon conformed with federal bonus depreciation, contributing to a state NOL carryforward of $113.7 million. We anticipate being able to use the full amount of both NOL carryforward balances in future years prior to expiration. The NOLs would otherwise expire in 20 years for federal and 15 years for Oregon.

Final tangible property regulations applicable to all taxpayers were issued by the Treasury Department on September 13, 2013. These regulations are generally effective for taxable years beginning on or after January 1, 2014. In addition, procedural guidance related to the regulations was recently 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 2014. We will evaluate the impact of this guidance once it is finalized.

2012 COMPARED TO 2011. The significant factors contributing to the $64.6 million decrease in operating cash flow for 2012 compared to 2011 are as follows:

- a decrease of $38.1 million in deferred environmental expenditures, net of recoveries, primarily due to insurance recoveries for environmental claims received in 2011;
- a decrease of $30.9 million in taxes accrued, primarily due to federal tax refunds totaling $36.6 million received in 2011; and
- a decrease of $26.2 million from changes in the deferred gas cost savings balance, which was reduced when approximately $39 million was refunded to customers in June and July 2012.

Partially offsetting these decreases was:

- an increase of $28.4 million from reductions in receivable balances primarily due to higher receivable balances from colder weather at the end of 2011, which were collected early in 2012.

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.

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Investing Activities

Investing activity highlights include:

In millions	2013	2012	2011
Total cash used in investing activities	$182.1	$184.7	$153.1
Capital expenditures	138.9	132.0	100.5
Proceeds from sale of assets	(8.6)	—	—
Utility gas reserves	54.1	54.1	50.6

2013 COMPARED TO 2012. The $2.5 million decrease in cash used in investing activities was due to proceeds received from the sale of assets. This decrease was partially offset by higher capital expenditures, reflecting increased investments for new customer acquisitions, completion of our Gasco Source Control water treatment station, and additional expenditures for system integrity and bare steel pipe removal.

2012 COMPARED TO 2011. The $31.6 million increase in cash used in investing activities was due to higher capital expenditures reflecting expenditures relating to a new utility training and back-up emergency operations facility, and several upgrades to existing building facilities. In addition, we also invested additional monies in utility gas reserves.

Over the five-year period 2014 through 2018, total utility capital expenditures are estimated to be between $600 and $700 million and utility expenditures under the existing gas reserves agreement are estimated to be around $90 million. The estimated level of utility capital expenditures over the next five years reflects assumptions for continued customer growth, technology, distribution system improvements and gas storage facilities. Most of the required funds are expected to be internally generated over the five-year period, and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing. In 2014, utility capital expenditures are estimated to be between $115 and $135 million, and non-utility capital investments are estimated to be less than $10 million. Additional non-utility spend for gas storage and other investments during and after 2014 will depend largely on future decisions about potential expansion opportunities in gas storage and pipeline projects. Gas storage segment capital expenditures in 2014 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	2013	2012	2011
Total cash provided by (used in) financing activities	$6.3	$18.9	$(78.0)
Change in short-term debt	(2.1)	48.7	(115.8)
Change in long-term debt	50.0	10.0	80.0

2013 COMPARED TO 2012. The $12.6 million decrease in cash provided by financing activities was primarily due to changes in our short-term debt balances, which decreased $2.1 million in 2013 compared to an increase of $48.7 million in 2012. This decrease was partially offset by changes in our long-term debt balances, which increased due to $40 million of long-term debt retired in 2012. We continue to use long-term debt proceeds to finance capital expenditures, refinance maturing short-term or long-term debt maturities, and to fund other general corporate purposes.

2012 COMPARED TO 2011. The $97.0 million increase to cash provided by financing activity was primarily due to changes in our short-term debt balances, which increased $48.7 million in 2012 compared to a decrease of $115.8 million in 2011. In 2012, we retired $40 million of long-term debt and issued $50 million of long-term debt.

We have a stock repurchase program approved through May 2014 which provides authorization to repurchase up to 2.8 million shares of NW Natural common stock or up to $100 million. The purchases may be made in the open market or through privately negotiated transactions. No repurchases were made in 2013, 2012 or 2011 under the program. Since the program's inception, we have repurchased an aggregate 2.1 million shares of common stock at a total cost of $83.3 million, at an average price of $39.19 per share. See Part II, Item 5, “Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities” above.

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 are allocated between operation and maintenance expenses, capital expenditures, and the deferred regulatory balancing account, totaled $21.5 million in 2013, an increase of $2.4 million from 2012. The fair market value of pension assets in this plan increased to $267.1 million at December 31, 2013 from $249.6 million at December 31, 2012. The increase was due to a return on plan assets of $22.9 million plus $11.7 million in employer contributions, partially offset by benefit payments of $17.1 million.

We make contributions to company-sponsored qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plans were underfunded by $95.3 million at December 31, 2013. We plan to make contributions during 2014 of $15 million.

We also contributed to a multiemployer pension plan for our union employees (the Union Plan, or otherwise known as Western States Plan) pursuant to our collective bargaining agreement. We made contributions totaling $0.5 million to the Union Plan in 2013 and $0.4 million in 2012. Effective December 22, 2013, we withdrew from the plan and have been assessed a withdrawal liability of approximately $8.3 million, which requires NW Natural to contribute $0.6 million

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each year to the plan for the next 20 years. See Note 8 for further pension disclosures.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2013, 2012, and 2011, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission (SEC) method, were 3.16, 3.26, and 3.38, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. The prior period amounts have been corrected for the prior period error identified in the first quarter of 2013. See Note 16 for detail on the prior period correction and Exhibit 12 for the detailed ratio calculation.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. See Part II, Item 7, “Application of Critical Accounting Policies and Estimates” below. At December 31, 2013, we had a regulatory asset of $148.4 million for deferred environmental costs, which includes $98.1 million for additional costs expected to be paid in the future and $20.3 million of accrued interest. Additionally, in 2014, a settlement was reached in our environmental insurance recovery litigation with remaining insurers. If it is determined that insurance recoveries for environmental costs are insufficient and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities see Note 15, for an update regarding insurance settlements see Note 17, and see also "Results of Operations—Regulatory Matters—Rate Mechanisms—Environmental Costs".

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.

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APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In preparing our financial statements using GAAP, management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management’s most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or used different assumptions. Our most critical estimates and judgments include accounting for:

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

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, regulatory and competitive conditions, we believe that it is reasonable to expect continued application of regulatory accounting for our utility activities, and that our regulatory assets and liabilities at December 31, 2013 are reasonably likely to be recovered or refunded through future customer rates. 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 against earnings in the period such determination is made. The net balance in regulatory asset and liability accounts as of December 31, 2013 and 2012 was $60.4 million and $125.8 million, respectively. See Note 2 "Industry Regulation".

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. Revenues are accrued for gas delivered and services rendered to customers, but not yet billed, based on estimates from the last meter reading date to month end (accrued unbilled revenue). Accrued unbilled revenue is based on a percentage estimate of amounts unbilled each month, which is dependent upon a number of factors, some of which require management’s judgment. These factors include:

- total gas receipts and deliveries;
- customer meter reading dates;
- customer usage patterns; and
- weather.

Accrued unbilled revenue estimates are reversed the following month when actual billings occur. Accrued unbilled revenue at December 31, 2013 and 2012 was $61.5 million and $57.0 million, respectively. The increase in accrued unbilled revenue at year-end 2013 was primarily due to higher volumes in December 2013, reflecting colder weather late in the month, and higher customer billing rates.

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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%:

	2013	
In millions	Up 1%	Down 1%
Unbilled revenue increase (decrease)	$0.6	$(0.6)
Utility margin increase (decrease) [(1)]	—	—
Net income increase (decrease)	—	—

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

SENATE BILL 408 AND 967. From 2007 through 2010, utility revenues included the recognition of a regulatory adjustment for income taxes paid (SB 408). Under Oregon SB 408, utilities were required to automatically implement a rate refund, or a rate surcharge, to utility customers on an annual basis. The refund or surcharge amount was based on estimated differences between income taxes paid and income taxes collected in customer rates. We recorded the refund, or surcharge, each quarter based on the annual amount to be recognized.

In 2011, SB 967 effectively repealed SB 408. The new law required utilities in Oregon to reverse amounts accrued for the 2010 and 2011 tax years, which resulted in us recording a one-time pre-tax charge to earnings in the second quarter of 2011 in the amount of $7.4 million ($4.4 million after-tax or 17 cents per share). For further discussion, see "Results of Operations—Business Segments-Local Gas Distribution Utility Operations—Regulatory Adjustment for Income Taxes Paid" above.

NON-UTILITY REVENUES. Non-utility revenues, derived primarily from our gas storage segment, are recognized upon delivery of service to customers. Revenues from our asset management partner are recognized as earned based on multiple revenue elements, which is generally over the period of each asset management deal, except for contracts with a guaranteed amount, which are amortized pro-rata over the life of the contract.

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. The accounting rules for determining whether a contract meets the definition of a derivative instrument or qualifies for hedge accounting treatment are complex. The contracts that meet the definition of a derivative instrument 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 (AOCI) under common stock equity on the balance sheet. Our derivative contracts outstanding at December 31, 2013 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.

Commodity-based derivative contracts entered into by the utility after our annual PGA filing for the current gas contract period are subject to a regulatory incentive sharing mechanism in Oregon. See "Results of

Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" above. The portion not deferred to a regulatory account pursuant to that sharing agreement is recognized either in current income for contracts not qualifying for hedge accounting or in AOCI for contracts qualifying for hedge accounting.

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

In millions	2013	2012	2011
Net utility loss on:			
Commodity			
Swaps	$(11.0)	$(69.5)	$(53.8)
Options	—	(0.7)	(2.7)
Total net loss realized	$(11.0)	$(70.2)	$(56.5)

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

Pensions and Postretirement Benefits

We maintain a qualified non-contributory defined benefit pension plan, several 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. Effective December 31, 2012, the defined benefit pension plans for union and non-union employees were merged into one plan. The qualified defined benefit retirement plans for union and non-union employees were 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

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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. As such, 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".

In 2011, we received regulatory approval from the OPUC and began deferring 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, 2013, the cumulative amount deferred for future pension cost recovery was $25.7 million. The regulatory balancing account includes the recognition of accrued interest on the account balance at the utility's actual cost of long-term debt.

A number of factors, as discussed above, are considered in developing pension and postretirement benefit assumptions. For the December 31, 2013 measurement date, we reviewed and updated:

- our weighted-average discount rate assumptions for pensions went from 3.85% in 2012 to 4.73% in 2013, and our weighted-average discount rate assumptions for other postretirement benefits went from 3.56% in 2012 to 4.45% in 2013. The new 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 bonds rated AA- or higher by S&P or Aa3 or higher by Moody’s;
- our expected annual rate of future compensation increases, which remained unchanged at a range of 3.25% to 5.0%;
- our expected long-term return on qualified defined benefit plan assets, which remained unchanged at a rate of 7.50%; and
- other key assumptions, which were based on actual plan experience and actuarial recommendations.

At December 31, 2013, our net pension liability (benefit obligations less market value of plan assets) for the qualified defined benefit plan decreased $59.1 million compared to 2012. The decrease in our net pension liability is primarily due to the $41.6 million decrease in our pension benefit obligation and an increase of $17.5 million in plan assets. The liability for non-qualified plans decreased $3.2 million, and the liability for other postretirement benefits decreased $4.4 million in 2013.

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, 2013, the actual annualized returns on plan assets, net of management fees, for the past one-year, five-years, and 10-years were 9.8%, 9.6%, and 5.6%, 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 future changes in certain actuarial assumptions:

Dollars in millions	Change in Assumption	Impact on 2013 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2013
Discount rate:	(0.25)%		
Qualified defined benefit plans		$1.0	$11.4
Non-qualified plans		—	0.7
Other postretirement benefits		—	0.7
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 changes 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 2014, we expect to

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contribute approximately $15 million under the adjusted 24-month segment rate using MAP-21 corridor.

Income Taxes
We account for income taxes in accordance with accounting standards that require the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amount and tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. At December 31, 2013 and 2012, our net long-term deferred tax liability totaled $486.8 million and $444.4 million, respectively. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our tax returns. For state and local income taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. At December 31, 2013, we did not record a valuation allowance due to our expectation that all of these assets and liabilities will be realized.

These accounting standards also require the recognition of deferred income tax assets and liabilities for temporary differences where regulators require us to flow through deferred income tax benefits or expenses in the ratemaking process of the regulated utility (regulatory tax assets and liabilities). This is consistent with the ratemaking policies of the OPUC and WUTC. Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from, or refunded to, customers in future rates. As part of the Oregon general rate case, the OPUC ruled that we cannot recover deferred amounts that represent the increase in deferred income taxes caused by the 2009 Oregon tax rate change. As a result, we recognized a one time, after tax charge of $2.7 million in 2012 to write off the regulatory asset related to this rate change. At December 31, 2013 and 2012, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $56.2 million and $60.3 million, respectively, and recorded an offsetting deferred tax liability. We are currently recovering these pre-1981 deferred tax assets over a period of approximately 25 years. See Note 2 and Note 9.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, we would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheet. As of December 31, 2013, we had no reserves for uncertain tax positions.

In 2012, the Company settled an examination of tax years 2006 through 2009 with the state of Oregon. This settlement resulted in an additional $0.2 million state tax expense due to Oregon, including interest. However, the Company also filed an amended tax return with the state of California for tax year 2007 in which it claimed a refund of $0.2 million

and recognized a reduction in state tax expense of $0.2 million. The net effect of these two state tax changes was negligible.

The Company is currently under IRS examination for tax years 2009-2011 and we expect resolution in 2014. The Company is also subject to examination for tax year 2012.
To date, the IRS has not proposed any material adjustments.

Interest and penalties related to any future income tax deficiencies would be recorded in income tax expense in our consolidated statements of income.

Environmental Contingencies

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. Estimates of loss contingencies, including estimates of legal costs when such costs are probable of being incurred and are reasonably estimable and related disclosures are updated when new information becomes available. Estimating probable losses requires an analysis of uncertainties that often depends upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results. When information is sufficient to estimate only a range of potential liabilities, and no point within the range is more likely than any other, we recognize an accrued liability at the low end of the range and disclose the range. See "Contingent Liabilities" above. It is possible, however, that the actual range of potential liabilities could be significantly different than estimated amounts currently accrued and disclosed, with the result that our financial condition and results of operations could be materially affected by changes in the assumptions or estimates related to these contingencies.

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. Using sampling data, feasibility studies, existing technology, and enacted laws and regulations, we estimate that the total future expenditures for environmental investigation, monitoring and remediation are $98.1 million as of December 31, 2013. 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, then 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.

We continue to seek recovery of such costs through insurance and through customer rates, and we believe recovery of these costs is probable. In 2014, a settlement was reached in our environmental insurance recovery

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litigation with remaining insurers. In addition, we have a new SRRM in Oregon with a proceeding currently open to resolve implementation issues including the prudence of deferred costs, the allocation of insurance proceeds, and an earnings test that would be applied to past and future deferred costs. As there is uncertainty surrounding this mechanism and the open proceeding, we will continue to carefully assess these environmental assets for recoverability. If it is determined that insurance recoveries for environmental costs are insufficient and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made. See "Results of Operations—Rate Matters—Rate Mechanisms—Environmental Costs" above, Note 15, and Note 17.

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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 facility, to meet expected requirements of our core utility customers. Our gas purchase 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.

Commodity Price and Storage Value Risk

Natural gas commodity prices and storage values are subject to market fluctuations due to unpredictable factors including weather, pipeline transportation congestion, drilling technologies, potential market speculation and other factors that affect supply and demand. In addition to managing storage positions through a combination of short- and long-term fixed price contracts, we use financial swap and option contracts to convert certain natural gas supply contracts from floating prices to fixed or capped prices. We also manage risk with physical gas reserves from a long-term investment in working interests in gas leases operated by Encana. These financial hedge contracts and gas reserve volumes are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. We also regularly monitor and manage the financial exposure and liquidity risk of our storage position.

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.

Foreign Currency Risk

The costs of certain natural gas commodity supplies and certain pipeline 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 and commodity-related demand charges paid in Canadian dollars. If all of the foreign currency forward contracts had been settled on December 31, 2013, a loss of $0.3 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 monthly market index price tied to liquid exchange points, and we have adequate storage flexibility, we believe that it is unlikely that a supplier default would have an adverse effect on our financial condition or results of operations.

CREDIT EXPOSURE TO FINANCIAL DERIVATIVE COUNTERPARTIES. Based on estimated fair value at December 31, 2013, our overall credit exposure relating to commodity contracts is considered to be immaterial as it reflects amounts we owed to our 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. As of December 31, 2013, actual financial swap and option derivative credit risk exposure totals $5.4 million, which reflects amounts that counterparties owe to us.

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	2013	2012	
AAA/Aaa	$—	$—	
AA/Aa	4.5	(5.0	)
A/A	0.9	—	
BBB/Baa	—	—	
Total	$5.4	$(5.0	)

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 a 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.

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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 that 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.

CREDIT EXPOSURE TO INSURANCE COMPANIES FOR ENVIRONMENTAL DAMAGE CLAIMS. We regularly monitor the financial condition of insurance companies who provide or provided general liability insurance policy coverage to NW Natural and its predecessors with respect to environmental damage claims. We have filed claims for our environmental costs with a number of insurance companies. The majority of these companies have credit ratings of A or better from A.M. Best Co. (AM Best). AM Best is a global independent credit rating agency who has provided quantitative and qualitative analysis of insurance company balance sheet strength for over 100 years. AM Best uses a rating scale that ranges from A++ (Superior financial strength) to F (In Liquidation), with a rating of A considered Excellent. A strong credit rating from AM Best is not a guarantee that an insurance company will be able to meet its contractual obligations. The remaining insurance companies who do not have credit ratings of A or better are expected to have sufficient funds in reserves to cover these claims. Our credit exposure to insurance companies for environmental claims could be material; however, we have recently settled with remaining insurers for these claims with payment expected in 2014. See Note 17. In the event we are unable to recover environmental expenses from these insurance policies, we will seek recovery of unreimbursed amounts through customer rates.

Weather Risk

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. We have a weather normalization mechanism 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, 2013, approximately 8% of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 10% 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 less than 20% of all residential and commercial customers. See "Results of Operations—Regulatory Matters—Rate Mechanism—Weather Normalization Tariff" 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) and 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, 2013. 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 (1992).

Based on our assessment and those criteria, management has concluded that we maintained effective internal control over financial reporting as of December 31, 2013.

The effectiveness of internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

/s/ Gregg S. Kantor
Gregg S. Kantor
President and Chief Executive Officer

/s/ Stephen P. Feltz
Stephen P. Feltz
Senior Vice President and Chief Financial Officer

February 28, 2014

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 table of contents present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 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 table of contents 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, 2013, based on criteria established in Internal Control - Integrated Framework (1992) 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 28, 2014

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
In thousands, except per share data	2013	2012	2011
Operating revenues	$758,518	$730,607	$828,055
Operating expenses:			
Cost of gas	373,298	355,335	458,508
Operations and maintenance	136,613	129,477	125,417
General taxes	29,956	30,598	29,281
Depreciation and amortization	75,905	73,017	70,004
Total operating expenses	615,772	588,427	683,210
Income from operations	142,746	142,180	144,845
Other income and expense, net	4,669	3,159	3,112
Interest expense, net	45,172	43,157	42,088
Income before income taxes	102,243	102,182	105,869
Income tax expense	41,705	43,403	42,825
Net income	60,538	58,779	63,044
Other comprehensive income:			
Change in employee benefit plan liability, net of taxes of ($1,304) for 2013, $1,339 for 2012, and $1,161 for 2011	1,998	(2,156)	(1,779)
Amortization of non-qualified employee benefit plan liability, net of taxes of ($608) for 2013, ($434) for 2012, and ($383) for 2011	935	665	583
Comprehensive income	$63,471	$57,288	$61,848
Average common shares outstanding:			
Basic	26,974	26,831	26,687
Diluted	27,027	26,907	26,744
Earnings per share of common stock:			
Basic	$2.24	$2.19	$2.36
Diluted	2.24	2.18	2.36
Dividends declared per share of common stock	1.83	1.79	1.75

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2013	2012
Assets:		
Current assets:		
Cash and cash equivalents	$9,471	$8,923
Accounts receivable	81,889	61,229
Accrued unbilled revenue	61,527	56,955
Allowance for uncollectible accounts	(1,656)	(2,518)
Regulatory assets	22,635	52,448
Derivative instruments	5,311	1,950
Inventories	60,669	67,602
Gas reserves	20,646	14,966
Income taxes receivable	3,534	2,552
Deferred tax assets	45,241	—
Other current assets	21,181	19,592
Total current assets	330,448	283,699
Non-current assets:		
Property, plant, and equipment	2,918,739	2,786,008
Less: Accumulated depreciation	855,865	812,396
Total property, plant, and equipment, net	2,062,874	1,973,612
Gas reserves	121,998	84,693
Regulatory assets	369,603	382,255
Derivative instruments	1,880	3,639
Other investments	67,851	67,667
Restricted cash	4,000	4,000
Other non-current assets	12,257	13,555
Total non-current assets	2,640,463	2,529,421
Total assets	$2,970,911	$2,813,120

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2013	2012
Liabilities and equity:		
Current liabilities:		
Short-term debt	$188,200	$190,250
Current maturities of long-term debt	60,000	—
Accounts payable	96,126	85,613
Taxes accrued	10,856	9,588
Interest accrued	7,103	5,953
Regulatory liabilities	28,335	20,792
Derivative instruments	1,891	10,796
Other current liabilities	40,280	45,444
Total current liabilities	432,791	368,436
Long-term debt	681,700	691,700
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	532,036	444,377
Regulatory liabilities	303,485	288,113
Pension and other postretirement benefit liabilities	149,354	215,792
Derivative instruments	615	578
Other non-current liabilities	119,058	74,497
Total deferred credits and other non-current liabilities	1,104,548	1,023,357
Commitments and contingencies (see Note 14 and Note 15)	—	—
Equity:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 27,075 and 26,917 at December 31, 2013 and 2012, respectively	364,549	356,571
Retained earnings	393,681	382,347
Accumulated other comprehensive loss	(6,358)	(9,291)
Total equity	751,872	729,627
Total liabilities and equity	$2,970,911	$2,813,120

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 Dec. 31, 2010	$342,978	$355,251	$(6,604)	$691,625
Comprehensive income (loss)	—	63,044	(1,196)	61,848
Dividends paid on common stock	—	(46,690)	—	(46,690)
Tax expense from employee stock option plan	(26)	—	—	(26)
Stock-based compensation	1,769	—	—	1,769
Issuance of common stock	3,632	—	—	3,632
Common stock expense	30	(30)	—	—
Balance at Dec. 31, 2011	348,383	371,575	(7,800)	712,158
Comprehensive income (loss)	—	58,779	(1,491)	57,288
Dividends paid on common stock	—	(48,007)	—	(48,007)
Tax expense from employee stock option plan	(149)	—	—	(149)
Stock-based compensation	1,291	—	—	1,291
Issuance of common stock	7,046	—	—	7,046
Balance at Dec. 31, 2012	356,571	382,347	(9,291)	729,627
Comprehensive income	—	60,538	2,933	63,471
Dividends paid on common stock	—	(49,204)	—	(49,204)
Tax expense from employee stock option plan	(242)	—	—	(242)
Stock-based compensation	2,169	—	—	2,169
Issuance of common stock	6,051	—	—	6,051
Balance at Dec. 31, 2013	$364,549	$393,681	$(6,358)	$751,872

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
In thousands	2013	2012	2011
Operating activities:			
Net income	$60,538	$58,779	$63,044
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	75,905	73,017	70,004
Regulatory amortization of gas reserves	11,089	6,340	1,143
Deferred tax liabilities, net	46,483	42,079	46,319
Non-cash expenses related to qualified defined benefit pension plans	5,666	5,448	7,191
Contributions to qualified defined benefit pension plans	(11,700)	(23,500)	(22,045)
Deferred environmental expenditures, net of recoveries	(16,679)	(12,503)	25,586
Other	(2,580)	(2,350)	(863)
Changes in assets and liabilities:			
Receivables	(26,094)	22,170	(6,246)
Inventories	6,933	6,761	6,022
Taxes accrued	286	3,334	34,189
Accounts payable	7,422	(602)	148
Interest accrued	1,150	96	675
Deferred gas costs	(5,245)	(17,644)	8,565
Other, net	23,216	7,413	(270)
Cash provided by operating activities	176,390	168,838	233,462
Investing activities:			
Capital expenditures	(138,924)	(132,029)	(100,534)
Utility gas reserves	(54,077)	(54,085)	(50,597)
Proceeds from sale of assets	8,638	—	—
Restricted cash	—	—	(3,076)
Other	2,231	1,437	1,142
Cash used in investing activities	(182,132)	(184,677)	(153,065)
Financing activities:			
Common stock issued, net	5,964	6,758	3,040
Long-term debt issued	50,000	50,000	90,000
Long-term debt retired	—	(40,000)	(10,000)
Change in short-term debt	(2,050)	48,650	(115,835)
Cash dividend payments on common stock	(49,204)	(48,007)	(46,690)
Other	1,580	1,528	1,464
Cash provided by (used in) financing activities	6,290	18,929	(78,021)
Increase in cash and cash equivalents	548	3,090	2,376
Cash and cash equivalents, beginning of period	8,923	5,833	3,457
Cash and cash equivalents, end of period	$9,471	$8,923	$5,833
Supplemental disclosure of cash flow information:			
Interest paid	$44,022	$43,061	$41,413
Income taxes paid	870	2,979	1,756

See Notes to Consolidated Financial Statements

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

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

During the first quarter of 2013, we identified an error in the rate used to calculate interest on regulatory assets. We assessed the materiality of this error on prior period financial statements and concluded it was not material to any prior annual or interim periods; however, the cumulative impact would have been material to the annual and interim periods for 2013, if corrected in 2013. As a result, in accordance with accounting standards, we have revised our prior period financial statements as shown in Note 16 to correct this error.

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

2. SIGNIFICANT ACCOUNTING POLICIES UPDATE

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 that 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. 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 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 provides 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	2013	2012
Current:		
Unrealized loss on derivatives(1)	$1,891	$10,796
Other(2)	20,744	41,652
Total current	$22,635	$52,448
Non-current:		
Unrealized loss on derivatives(1)	$615	$578
Pension balancing(3)	25,713	14,727
Income tax asset	51,814	55,879
Pension and other postretirement benefit liabilities(3)	125,855	182,688
Environmental costs(4)	148,389	121,144
Other(2)	17,217	7,239
Total non-current	$369,603	$382,255

	Regulatory Liabilities	
In thousands	2013	2012
Current:		
Gas costs	$7,510	$9,100
Unrealized gain on derivatives(1)	5,290	1,950
Other(2)	15,535	9,742
Total current	$28,335	$20,792
Non-current:		
Gas costs	$2,172	$—
Unrealized gain on derivatives(1)	1,880	3,639
Accrued asset removal costs	296,294	281,213
Other(2)	3,139	3,261
Total non-current	$303,485	$288,113

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

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

(3) Certain utility pension costs are approved for regulatory deferral, including amounts recorded to the pension balancing account, to mitigate the effects of higher and lower pension expenses. Pension costs that are deferred include an interest component when recognized in net periodic benefit costs. See Note 8.

(4) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. For further information on environmental matters, see Note 15.

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 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, 2013 are prudent. We annually review all regulatory assets and liabilities for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances in the period such determination is made.

New Accounting Standards

Recently Adopted Standards

BALANCE SHEET OFFSETTING. In December 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance regarding the offsetting of assets and liabilities on the balance sheet. The standard is intended to provide more comparable guidance between the GAAP and international accounting standards by requiring entities to disclose both gross and net amounts for assets and liabilities offset on the balance sheet as well as other disclosures concerning their enforceable master netting arrangements. This guidance was effective for annual reporting periods beginning on or after January 1, 2013. The adoption of this standard did not have a material effect on our financial statement disclosures. See Note 13.

RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME. In February 2013, the FASB issued authoritative guidance, which requires an entity to present significant amounts reclassified from each component of accumulated other comprehensive income (AOCI). This standard is intended to improve the reporting of these reclassifications by presenting the information concerning amounts reclassified into net income from AOCI in a single location. This information has historically has been presented throughout the financial statements. This guidance was effective for reporting periods beginning after December 15, 2012. The adoption of this standard did not have a material effect on our financial statement disclosures. See Note 8.

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Recently Issued Accounting Pronouncements

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

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

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 “Allowance for Funds Used During Construction” 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 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 upon 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 that is recorded in other income and expense, net 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% in 2013, 2012, and 2011, reflecting the approximate weighted average economic life of the property. This includes 2013 weighted average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.2% for gas storage facilities, 4.3% for general plant, and 4.1% 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 rates were 0.3% in 2013 and 2012, and 0.5% in 2011.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate that 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.

If such factors indicate a potential impairment, we assess the recoverability by determining if the carrying value of the asset exceeds the sum of the projected future cash flows over the remaining economic life of the asset. An asset is determined to be impaired when the carrying value is not recoverable through undiscounted future cash flows, and in those cases, we would estimate the fair value of the asset using appropriate valuation methodologies, which may include an estimate of discounted cash flows. Any impairment would be measured as the difference between the asset’s carrying amount and its estimated fair value.

While we determined there were no material impairments of long-lived assets during the year ended December 31, 2013, if our gas storage facilities experience sustained decreases

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in future cash flows due to a prolonged, slow recovery of the gas storage market, future assessments could result in an impairment.

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, 2013 and 2012, outstanding checks of approximately $2.8 million and $2.3 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 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, 2013 and 2012 was $61.5 million and $57.0 million, respectively.

From 2007 through 2010, utility margin also included the recognition of a regulatory adjustment for income taxes paid pursuant to a legislative rule (commonly referred to as SB 408) in effect for certain gas and electric utilities in Oregon. In 2011, SB 408 was repealed and replaced by Senate Bill SB 967. SB 967 required utilities to eliminate amounts accrued under SB 408, which resulted in a one-time pre-tax charge of $7.4 million in 2011.

Non-utility revenues are derived primarily from the gas storage segment. At our Mist underground storage facility, revenues are recognized upon delivery of services to customers. 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 primarily from an independent energy marketing company that optimizes commodity 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. See Note 4.

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.

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. With respect to these trade receivables, including accrued

unbilled revenue, we establish an allowance for uncollectible accounts (allowance) 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. With respect to large individual customer receivables, a specific allowance is established and recorded 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 to be 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 the level of natural gas prices. Each quarter the allowance for uncollectible accounts is adjusted, 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 that are injected into storage are priced into inventory based on actual purchase costs. Utility gas inventories that are 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 the Gill Ranch storage facility, consist primarily of natural gas that we 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. It is recorded at original cost and classified as a long-term plant asset.

Material 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 $51.4 million and $58.8 million at December 31, 2013 and 2012, respectively. At December 31, 2013 and 2012, our materials and supplies inventories totaled $9.3 million and $8.8 million, respectively.

Gas Reserves

Our gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Transactional costs to enter into the agreement and payments by NW Natural to acquire gas reserves are recognized as gas reserves 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

In accordance with accounting for derivatives and hedges, we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. Accounting for derivatives requires that changes in the fair value be recognized currently in earnings unless specific 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. The Company's 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 that PGA year has begun 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, 2013, 2012 and 2011, we selected a 90% deferral of gas cost differences. 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 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 upon quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based upon 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 that 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; (h) and other relevant economic measures.

Income Tax Expense
NW Natural and its wholly-owned subsidiaries file consolidated federal, state, and local income tax returns. Income taxes are currently allocated based on each entity's respective taxable income or loss and tax credits as if each entity filed a separate return. We account for income taxes in accordance with accounting standards for income taxes. Accounting for income taxes requires recognition of deferred tax liabilities and assets for the future tax consequences of events that have been included in the consolidated financial statements or tax returns. Under this method, deferred

tax liabilities and assets are determined based on the difference 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. See Note 9.

Accounting for income taxes also requires recognition of deferred income tax assets and liabilities for temporary differences where regulators prohibit deferred income tax treatment for ratemaking purposes. We have recorded deferred tax liabilities of $56.2 million and $60.3 million at December 31, 2013 and 2012, respectively, to recognize future taxes payable resulting from transactions that have previously been reflected in the financial statements for these temporary differences. Regulatory assets or liabilities corresponding to such additional deferred income tax assets or liabilities may be recorded to the extent we believe they will be recoverable from or payable to customers through the ratemaking process. A corresponding regulatory asset has been recorded which represents the probable future revenue that will result from inclusion in rates charged to customers for taxes which will be paid in the future. The probable future revenue to be recorded takes into consideration the additional future taxes which will be generated by that revenue. Amounts applicable to income taxes due from customers primarily represent differences between the financial statement and tax basis of net utility plant in service and actual removal costs incurred.

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 or lease.

Environmental Contingencies
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. 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.

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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, then 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.

Subsequent Events
See Note 17 for information regarding the Company's environmental insurance settlements.

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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. Diluted earnings per share are calculated as follows:

In thousands, except per share data	2013	2012	2011
Net income	$60,538	$58,779	$63,044
Average common shares outstanding - basic	26,974	26,831	26,687
Additional shares for stock-based compensation plans (See Note 6)	53	76	57
Average common shares outstanding - diluted	27,027	26,907	26,744
Earnings per share of common stock - basic	$2.24	$2.19	$2.36
Earnings per share of common stock - diluted	$2.24	$2.18	$2.36
Additional information:			
Antidilutive shares not included in net income per diluted common share calculation	26	1	2

4. SEGMENT INFORMATION

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

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 90% of our customers are located in Oregon and 10% 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. No individual customer or industry group accounts for over 10% of our utility revenues or utility margins.

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 under contractual arrangement, the results of which are included in this business segment. For the years ended December 31, 2013, 2012 and 2011, this business segment derived a majority of its revenues from firm and interruptible gas storage contracts and from asset management services.

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 gas storage segment also include revenues, net of amounts shared with core utility customers, from management of utility assets at Mist and upstream capacity when not needed to serve utility customers. In Oregon, the gas storage segment retains 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 credited to a deferred regulatory account for crediting back to utility customers. We have a similar sharing mechanism in Washington for revenue derived from storage and third party asset management services.

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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 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.

Other

We have immaterial 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 an interstate gas transmission pipeline in Oregon (Palomar) and other pipeline assets in NNG Financial. For more information on Palomar, see Note 12. Other also includes some operating and non-operating revenues and expenses of the parent company that cannot be allocated to utility operations.

NNG Financial holds certain non-utility financial investments, but its 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 $1.2 million and $1.1 million at December 31, 2013 and 2012, respectively.

Segment Information Summary

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

In thousands	Utility	Gas Storage	Other	Total
2013				
Operating revenues	$727,182	$31,112	$224	$758,518
Depreciation and amortization	69,420	6,485	—	75,905
Income from operations	128,066	14,669	11	142,746
Net income	54,920	5,569	49	60,538
Capital expenditures	137,466	1,458	—	138,924
Total assets at December 31, 2013	2,644,367	310,097	16,447	2,970,911
2012				
Operating revenues	$699,862	$30,520	$225	$730,607
Depreciation and amortization	66,545	6,472	—	73,017
Income from operations	128,854	13,226	100	142,180
Net income	54,049	4,521	209	58,779
Capital expenditures	130,151	1,541	337	132,029
Total assets at December 31, 2012	2,505,655	291,568	15,897	2,813,120
2011				
Operating revenues	$801,478	$26,354	$223	$828,055
Depreciation and amortization	63,843	6,161	—	70,004
Income from operations	135,722	9,090	33	144,845
Net income (loss)	59,673	4,101	(730)	63,044
Capital expenditures	94,049	6,485	—	100,534

Utility Margin

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

In thousands	2013	2012	2011
Utility margin calculation:			
Utility operating revenues	$727,182	$699,862	$801,478
Less: Utility cost of gas	373,298	355,335	458,508
Utility margin	$353,884	$344,527	$342,970

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5. COMMON STOCK

Common Stock

As of December 31, 2013 and 2012, we had 100 million shares of common stock authorized. As of December 31, 2013, we had reserved 122,184 shares for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 96,991 shares under our Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). In the second quarter of 2012, our Restated Stock Option Plan (Restated SOP) was terminated for new stock option grants. There were 492,150 options outstanding at December 31, 2013, which were granted prior to termination of the plan. These options will remain outstanding to the earlier of their forfeiture, exercise or expiration.

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 2014 to repurchase up to an aggregate of 2.8 million shares, but not to exceed $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2013. 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, 2010	26,668
Sales to employees under ESPP	15
Stock-based compensation	24
Sales to shareholders under DRPP	49
Balance, December 31, 2011	26,756
Sales to employees under ESPP	18
Stock-based compensation	47
Sales to shareholders under DRPP	96
Balance, December 31, 2012	26,917
Sales to employees under ESPP	16
Stock-based compensation	42
Sales to shareholders under DRPP	100
Balance, December 31, 2013	27,075

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. A variety of equity programs may be granted under the LTIP. The Restated SOP was terminated for new stock option grants in 2012.

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, 2013. Shares awarded under the LTIP may be purchased on the open market or issued as new shares.

Of the 850,000 shares of common stock authorized for LTIP awards at December 31, 2013, there were 241,169 shares available for issuance under any type of award. This assumes that market, performance, and service based grants currently outstanding are awarded at the target level. Additionally, 250,000 shares of common stock were available for option grants at December 31, 2013. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2013 or 2012. 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.

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:

Expense in millions	Shares [1]	Expense During Award Year[3]	Total Expense for Award
Estimated award:			
2011-2013 grant[2]	9,516	$0.4	$1.0
Actual award:			
2010-2012 grant	9,924	0.5	1.2
2009-2011 grant	8,428	0.4	0.8

[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] This represents the estimated number of shares to be awarded as of December 31, 2013 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 2014.

[3]Amount represents the expense recognized in the third year of the vesting period noted above.

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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		2013	Cumulative Expense
Performance Period	Target	Maximum	Expense	December 31, 2013
2011-13	37,950	75,900	$390	$960
2012-14	35,340	70,680	603	1,238
2013-15	37,300	74,600	486	486
Total	110,590	221,180	$1,479	

For each of these performance periods, awards will be based on total shareholder return relative to a peer group of gas distribution companies over the three-year performance period and on performance results achieved relative to specific core and non-core strategies. Compensation expense is recognized in accordance with the accounting standard 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, 2013 and 2012 was $43.39 and $51.42 per share, respectively. The weighted-average grant date fair value of shares vested during the year was $30.86 per share and for shares granted during the year was $38.96 per share. As of December 31, 2013, there was $1.6 million of unrecognized compensation cost related to the unvested portion of performance awards expected to be recognized through 2015.

Restricted Stock Units

In 2012, the Company began granting RSUs under the LTIP instead of stock options under the Restated SOP. The majority of RSUs include a performance-based threshold and generally have a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of the RSU. The fair value of the RSU is equal to the closing market price of the Company's common stock on the grant date.

Information regarding the RSU activity is summarized as follows:

	Number of RSUs	Weighted - Average Price Per RSU
Nonvested, Dec. 31, 2011	—	$—
Granted	25,224	47.58
Vested	—	—
Forfeited	(360)	48.00
Nonvested, Dec. 31, 2012	24,864	47.57
Granted	25,748	45.38
Vested	(5,455)	48.01
Forfeited	(590)	46.58
Nonvested, Dec. 31, 2013	44,567	46.27

As of December 31, 2013, there was $1.5 million of unrecognized compensation cost from grants of RSUs,

which is expected to be recognized over a period extending through 2017.

Restated Stock Option Plan

The Restated SOP was terminated for new option grants in 2012; however, options that had been 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. We did not grant new stock options during 2012 or 2013.

At December 31, 2013, a total of 492,150 shares of common stock remained reserved for issuance under the Restated SOP. As the plan is closed, there are no additional shares available for grant. Options under the Restated SOP were granted only 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 up to 10 years and 7 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.

The fair value of each stock option is estimated on the grant date using the Black-Scholes option pricing model with the following weighted average assumptions and outcomes:

	2011	
Risk-free interest rate	2.0	%
Expected life (in years)	4.5	
Expected market price volatility factor	24.5	%
Expected dividend yield	3.8	%
Forfeiture rate	3.1	%
Weighted average grant date fair value	$6.73	

The expected life of our grants was calculated based on our actual experience with previously exercised option grants. The risk-free interest rate was based on the implied yield currently available on U.S. Treasury zero-coupon issues with a life equal to the expected life of the options. Historical data was used to estimate the volatility factor, measured on a daily basis, for a period equal to the duration of the expected life of the option awards. The dividend yield was based on management’s current estimate for future dividend payouts at the time of grant. We expense the total cost of stock option awards granted to retirement eligible employees at the date of grant in accordance with stock option accounting guidance and the retirement vesting provisions of our option agreements.

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Information regarding the Restated SOP activity is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value (In millions)
Balance outstanding, Dec. 31, 2010	490,460	$40.82	$2.8
Granted	122,700	45.74	n/a
Exercised	(24,185)	33.88	0.3
Forfeited	(9,750)	44.38	n/a
Balance outstanding, Dec. 31, 2011	579,225	42.09	3.4
Exercised	(46,825)	40.62	0.4
Forfeited	(2,475)	43.78	n/a
Balance outstanding, Dec. 31, 2012	529,925	42.22	1.3
Exercised	(33,800)	32.16	0.3
Forfeited	(3,975)	43.72	n/a
Balance outstanding, Dec. 31, 2013	492,150	42.89	0.6
Exercisable, Dec. 31, 2013	409,036	42.41	0.6

During 2013, cash of $1.1 million was received for option shares exercised and $0.2 million related tax benefit was realized. During 2013, 2012, and 2011, the total fair value of options that vested was $0.5 million, $0.6 million and $0.6 million, respectively. The weighted average remaining life of options exercisable and outstanding at December 31, 2013, was 4.8 years and 5.1 years, respectively. As of December 31, 2013, there was $0.2 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized during 2014.

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 $21,236 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	2013	2012	2011
Operations and maintenance expense, for stock-based compensation	$1,876	$1,668	$1,477
Income tax benefit	(765)	(707)	(597)
Net stock-based compensation effect on net income	$1,111	$961	$880
Amounts capitalized for stock-based compensation	$331	$294	$261

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, 2013 and 2012, the amounts of commercial paper debt outstanding were $188.2 million and $190.3 million, respectively, and the average interest rate was 0.3% at year-end for both periods. 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, 2013, our commercial paper had a maximum maturity of 136 days and an average maturity of 66 days. There were no bank loans outstanding at December 31, 2013 or 2012.

On December 20, 2012, NW Natural entered into a five-year $300 million credit agreement, pursuant to which we may extend commitments for two additional one-year periods subject to lender approval. In December 2013, we extended our commitment for an additional year with an updated maturity date of December 20, 2018. The credit agreement allows us to request increases in the total commitment amount up to a maximum amount of $450 million and permits letters of credit in an aggregate amount of up to $200 million. Any principal and unpaid interest owed on borrowings under the agreement are 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, 2013 and 2012.

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, 2013 and 2012.

Long-Term Debt
The issuance of first mortgage bonds (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.

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The Mortgage constitutes a first mortgage lien on substantially all of our utility property. In addition, our Gill Ranch subsidiary senior secured debt is secured by all of the membership interests in Gill Ranch as well as Gill Ranch's debt service reserve account.

Retirement of long-term debt for each of the 12-month periods through December 31, 2018 are as follows:

In thousands	
Year	
2014	$60,000
2015	40,000
2016	65,000
2017	40,000
2018	22,000

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

In thousands	2013	2012
First Mortgage Bonds		
8.26 % Series B due 2014	$10,000	$10,000
3.95 % Series B due 2014	50,000	50,000
4.70 % Series B due 2015	40,000	40,000
5.15 % Series B due 2016	25,000	25,000
7.00 % Series B due 2017	40,000	40,000
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	—
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
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 % Series due 2042	50,000	50,000
	701,700	651,700
Subsidiary Senior Secured Debt		
Gill Ranch debt due 2016	40,000	40,000
	741,700	691,700
Less: Current maturities of long-term debt	60,000	—
Total long-term debt	$681,700	$691,700

First Mortgage Bonds

NW Natural issued $50 million of FMBs on August 19, 2013 with a coupon rate of 3.542% and a 10-year maturity. In October 2012, the utility issued $50 million of FMBs with a coupon rate of 4.00% and a maturity date of October 31, 2042.

Subsidiary Senior Secured Debt

In November 2011, Gill Ranch issued $40 million of senior secured debt, which consists of $20 million of fixed rate debt with an interest rate of 7.75% and $20 million of variable interest rate debt with an interest rate of LIBOR plus 5.50%, or 7.00%, whichever is higher. At December 31, 2013, the variable interest rate was 7.00%. This debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW Natural. The maturity date of this debt is November 30, 2016.

Under the debt agreements, Gill Ranch is subject to certain covenants and restrictions including, but not limited to, a financial covenant that requires Gill Ranch to maintain minimum adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) at various levels over the term of the debt. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the debt agreements, Gill Ranch is also subject to a debt service reserve requirement of 10% of the outstanding principal amount, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on incurrence of additional debt. Gill Ranch was in compliance with all existing debt provisions and covenants for the year ended December 31, 2013.

Fair Value of Long-Term Debt

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

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	2013	2012
Carrying amount	$741,700	$691,700
Estimated fair value	806,359	834,664

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8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain qualified non-contributory defined benefit pension plans, a few non-qualified supplemental pension plans for eligible executive officers and other key employees, and other postretirement employee benefit plans. We also have qualified defined contribution plans (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 retirement benefits. Effective December 31, 2012, the defined benefit pension plans for non-union and union employees were merged into one plan. The qualified defined benefit retirement plan for non-union and union employees was closed to new participants effective January 1, 2007. The postretirement benefits plan for non-union employees was closed to new participants effective January 1, 2010. 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.

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	2013	2012	2013	2012
Reconciliation of change in benefit obligation:				
Obligation at January 1	$435,889	$391,127	$33,119	$30,049
Service cost	8,698	8,047	656	592
Interest cost	16,400	17,295	1,157	1,267
Net actuarial (gain) loss	(51,043)	37,615	(4,283)	3,182
Benefits paid	(18,855)	(18,195)	(1,895)	(1,971)
Obligation at December 31	$391,089	$435,889	$28,754	$33,119
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$249,603	$215,970	$—	$—
Actual return on plan assets	22,872	26,683	—	—
Employer contributions	13,442	25,145	1,895	1,971
Benefits paid	(18,855)	(18,195)	(1,895)	(1,971)
Fair value of plan assets at December 31	$267,062	$249,603	$—	$—
Funded status at December 31	$(124,027)	$(186,286)	$(28,754)	$(33,119)

Our qualified defined benefit pension plan has an aggregate benefit obligation of $362.4 million and $404.0 million at December 31, 2013 and 2012, respectively, and fair values of plan assets of $267.1 million and $249.6 million, respectively.

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

	Regulatory Assets						Other Comprehensive Income		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2013	2012	2011	2013	2012	2011	2013	2012	2011
Net actuarial (gain) loss	$(51,892)	$26,504	$66,404	$(4,283)	$3,182	$2,225	$(3,302)	$3,511	$2,948
Amortization of:									
Transition obligation	—	—	—	—	(411)	(411)	—	—	—
Prior service cost	(230)	(230)	(230)	(197)	(197)	(197)	7	35	(122)

Actuarial loss	(16,744)	(14,482)	(10,731)	(733)	(435)	(289)	(1,550)	(1,150)	(854)
Total	$(68,866)	$11,792	$55,443	$(5,213)	$2,139	$1,328	$(4,845)	$2,396	$1,972

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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	2013	2012	2013	2012	2013	2012
Prior service cost	$867	$1,097	$685	$882	$(5)	$(12)
Net actuarial loss	119,638	188,278	4,665	9,681	10,475	15,327
Total	$120,505	$189,375	$5,350	$10,563	$10,470	$15,315

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	2013	2012
Beginning balance	$(9,291)	$(7,800)
Amounts reclassified to AOCL	3,302	(3,495)
Amounts reclassified from AOCL:		
Amortization of prior service costs	(7)	(35)
Amortization of actuarial losses	1,550	1,134
Total reclassifications before tax	4,845	(2,396)
Tax (benefit) expense	(1,912)	905
Total reclassifications for the period	2,933	(1,491)
Ending balance	$(6,358)	$(9,291)

In 2014, an estimated $9.8 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $9.4 million of actuarial losses, and $0.4 million of prior service costs. A total of $1.0 million will be amortized from AOCL to earnings related to actuarial losses.

Our assumed discount rate was determined independently for each pension plan and other postretirement benefit plan 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 the Company's 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 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 plans’ 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 employees 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 expectation. All investments are expected to satisfy the requirements of the rule of prudent investments as set forth under the Employee Retirement Income Security Act of 1974. The approved asset classes 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. Our expected long-term rate of return is based upon historical index returns by asset class, adjusted by a factor based on our historical return experience, diversified asset allocation and active portfolio management by professional investment managers. The retirement trust fund is not currently invested in any NW Natural securities.

The following is our pension plan asset target allocation at December 31, 2013:

Asset Category	Target Allocation	
U.S. large cap equity	13.0	%
U.S. small/mid cap equity	8.5	
Non-U.S. equity	13.0	
Emerging markets equity	3.5	
Long government/credit	30.0	
High yield bonds	5.0	
Emerging market debt	5.0	
Real estate funds	6.0	
Absolute return strategy	11.0	
Real return strategy	5.0	

Our non-qualified supplemental defined benefit plan obligations were $28.7 million and $31.9 million at December 31, 2013 and 2012, respectively. These plans are not subject to regulatory deferral, and the changes in

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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. Although these are unfunded plans with no plan assets due to their nature as non-qualified plans, we indirectly fund a portion of our obligations with company- and trust-owned life insurance and other assets.

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, and the amortization of actuarial gains and losses.

Net periodic benefit costs consist of service costs, interest costs, and the amortization of actuarial gains and losses. the expected returns on plan assets and, in part, on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns, of which the differences are recognized over a three-year period or less from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

The following tables provide the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2013	2012	2011	2013	2012	2011
Service cost	$8,698	$8,047	$7,122	$656	$592	$614
Interest cost	16,400	17,295	18,134	1,157	1,267	1,404
Expected return on plan assets	(18,721)	(19,082)	(17,867)	—	—	—
Amortization of transition obligations	—	—	—	—	411	411
Amortization of prior service costs	223	195	352	197	197	197
Amortization of net actuarial loss	18,294	15,631	11,584	734	435	289
Net periodic benefit cost	24,894	22,086	19,325	2,744	2,902	2,915
Amount allocated to construction	(6,712)	(5,820)	(4,905)	(856)	(882)	(878)
Amount deferred to regulatory balancing account[1]	(9,115)	(7,876)	(6,008)	—	—	—
Net amount charged to expense	$9,067	$8,390	$8,412	$1,888	$2,020	$2,037

[1] Effective January 1, 2011, the OPUC approved the deferral of certain pension expenses above or below the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower net periodic benefit costs in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return. See Note 2.

Net periodic benefit costs above are reduced by amounts capitalized to utility plant based on approximately 30% to 40% payroll overhead charge to construction work orders. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions, with the remaining net amount charged to expense and recognized in current earnings.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	3.84%	4.51%	5.49%	3.56%	4.33%	5.16%

Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50 %	8.00 %	8.25 %	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	4.73 %	3.85 %	4.51 %	4.45 %	3.56 %	4.33 %
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50 %	7.50 %	8.00 %	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, 2013 was 9.0% for pre-65 and 7.9% for 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 5.0% by 2021.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. 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	$73	$(64)
Effect on the accumulated postretirement benefit obligation	739	(660)

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The impact of a change in retirement benefit costs on operating results would be less than the amounts shown above because a portion would be capitalized to utility plant, and a certain amount would be recorded to the regulatory balancing account with the remaining amount recognized in current earnings.

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:		
2012	$25,559	$1,971
2013	13,907	1,895
2014 (estimated)	15,607	1,892
Benefit Payments:		
2011	18,269	1,870
2012	18,195	1,971
2013	18,855	1,895
Estimated Future Benefit Payments:		
2014	19,450	1,892
2015	20,033	1,927
2016	20,671	2,001
2017	21,424	2,053
2018	22,337	2,112
2019-2023	129,177	10,823

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 new 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 addition, in July 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 as well as increasing the operational costs of running a pension plan. Our qualified defined benefit pension plan is currently underfunded by $95.3 million at December 31, 2013. Including the impacts of MAP-21, we expect to make contributions during 2014 of approximately $15 million.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit plans referred to above, we contribute to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan) in accordance with our collective bargaining agreement. The employer identification number of the plan is 94-6076144. The cost of

this plan, and corresponding future liabilities, are in addition to pension amounts in the tables above. The Western States Plan is managed by a board of trustees that includes equal representation from participating employers and labor unions. Contribution rates are established by collective bargaining agreements, and benefit levels are set by the board of trustees based on the advice of an independent actuary regarding the level of benefits that agreed-upon contributions are expected to support.

The Western States Plan has reported an accumulated funding deficit for the current plan year and remains in critical status. A plan is considered to be in critical status if its funded status is below 65%. Federal law requires pension plans in critical status to adopt a rehabilitation plan designed to restore the financial health of the plan. Rehabilitation plans may specify benefit reductions, contribution surcharges, or a combination of the two. The Western States Plan trustees adopted a rehabilitation plan that reduced benefit accrual rates and adjustable benefits for active employee participants and increased future employer contribution rates. These changes are expected to improve the funded status of the plan. Our contributions to the Western States Plan amounted to $0.5 million in 2013 and $0.4 million in 2012, and 2011, which is approximately 4% to 5% of the total contributions to the plan by all employer participants.

Under the terms of our current collective bargaining agreement, which became effective in July 2009, we could withdraw from the Western States Plan at any time. 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 have been assessed a withdrawal liability of $8.3 million, which requires NW Natural to pay $0.6 million each year to the plan for the next 20 years. We have deferred the withdrawal liability to a regulatory account on the balance sheet.

Defined Contribution Plan
The Retirement K Savings Plan provided to our employees is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Employer contributions to this plan totaled $2.2 million in 2013 and 2012, and $2.4 million in 2011. 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.

Fair Value
Following 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.

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U.S. LARGE CAP EQUITY and U.S. SMALL/MID CAP EQUITY. These are level 1 and 2 assets. The level 1 assets consist of directly held stocks, and mutual funds with a readily determinable fair value, including a published net asset value (NAV). The level 2 assets consist of mutual funds 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, and mutual funds are valued at NAV. This asset class includes investments primarily in U.S. common stocks.

NON-U.S. EQUITY. These are level 1 and 2 assets. The level 1 assets consist of directly held stocks, and the level 2 assets consist of an open-end mutual fund and a commingled trust 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 mutual fund is valued at NAV, while the commingled trust is valued at the unit price of the trust. This asset class includes investments primarily in foreign equity common stocks.

EMERGING MARKETS EQUITY. These are level 1 assets representing a mutual fund with readily determinable fair value, including published NAV's. This asset class includes investments primarily in common stocks in emerging markets.

FIXED INCOME. This is a level 2 asset consisting of a mutual fund, valued at NAV, where NAV is not published, but the investment can be readily disposed of at NAV. This asset class includes investments primarily in investment grade debt and fixed income securities.

LONG GOVERNMENT/CREDIT. These are level 1 and 2 assets. The level 1 assets consist of a fixed-income mutual fund with readily determinable fair value, including a published NAV. The level 2 assets consist of directly held fixed-income securities whose values are determined by closing prices if available and by matrix prices for illiquid securities. 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 level 2 assets consisting of a limited partnership where valuation is not published but the investment can be readily disposed of at market value. This asset class includes investments primarily in high yield bonds.

EMERGING MARKET DEBT. These are level 1 assets consisting of a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes investments primarily in emerging market debt.

REAL ESTATE FUNDS. These are level 1 assets consisting of a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes investments primarily in real estate investment trust (REIT) securities.

ABSOLUTE RETURN STRATEGY. These are level 2 assets consisting of a hedge fund of funds where valuation is not published but the investment can be readily disposed of at unit price. 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 includes investments primarily in common stocks and fixed income securities.

REAL RETURN STRATEGY. These are level 1 assets representing a mutual fund with readily determinable fair value, including a published NAV. This asset class includes an investment in a broad range of assets primarily including fixed income, high-yield bonds, and emerging market debt.

CASH AND CASH EQUIVALENTS. These are level 2 assets representing mutual funds without published NAV's but the investment can be readily disposed of at NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date. This asset class primarily includes 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 financial instruments 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 that such changes could materially affect our investment account balances and the amounts reported as plan assets available for benefits 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, 2013			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$39,124	$79	$—	$39,203
U.S. small/mid cap equity	30,465	55	—	30,520
Non-U.S. equity	16,782	17,202	—	33,984
Emerging markets equity	7,405	—	—	7,405
Fixed income	—	367	—	367
Long government/credit	33,152	32,763	—	65,915
High yield bonds	—	12,890	—	12,890
Emerging market debt	9,987	—	—	9,987
Real estate funds	16,559	—	—	16,559
Absolute return strategy	—	35,339	—	35,339
Real return strategy	13,031	—	—	13,031
Cash and cash equivalents	—	1,418	—	1,418
Total investments	$166,505	$100,113	$—	$266,618

	December 31, 2012			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$29,047	$1,891	$—	$30,938
U.S. small/mid cap equity	21,624	1,312	—	22,936
Non-U.S. equity	13,931	15,812	—	29,743
Emerging markets equity	8,004	—	—	8,004
Fixed income	—	8,824	—	8,824
Long government/credit	30,098	29,249	—	59,347
High yield bonds	—	12,017	—	12,017
Emerging market debt	11,421	—	—	11,421
Real estate funds	15,992	—	—	15,992
Absolute return strategy	—	32,078	—	32,078
Real return strategy	12,932	—	—	12,932
Cash and cash equivalents	—	1,459	—	1,459
Total investments	$143,049	$102,642	$—	$245,691

	December 31,	
Receivables	2013	2012
Accrued interest and dividend income	$468	$388
Due from broker for securities sold	1,154	4,459
Total receivables	$1,622	$4,847
Liabilities		
Due to broker for securities purchased	$1,178	$935
Total investment in retirement trust	$267,062	$249,603

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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 the three years ended December 31:

Dollars in thousands	2013	2012	2011
Income taxes at federal statutory rate	$35,785	$35,764	$37,056
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,674	4,773	4,945
Amortization of investment and energy tax credits	(271)	(350)	(442)
Differences required to be flowed-through by regulatory commissions	2,357	1,718	1,647
Gains on company and trust-owned life insurance	(864)	(800)	(786)
Regulatory asset impairment	—	2,700	—
Other, net	24	(402)	405
Total provision for income taxes	$41,705	$43,403	$42,825
Effective tax rate	40.8%	42.5%	40.5%

The decrease in the effective income tax rate for 2013 compared to 2012 was primarily due to the one-time, after-tax charge of $2.7 million in 2012 related to the OPUC's rate case order that the Company could not recover deferred tax amounts resulting from the 2009 Oregon income tax rate change.

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

In thousands	2013	2012	2011
Current			
Federal	$(62)	$1,693	$130
State	(11)	99	(929)
	(73)	1,792	(799)
Deferred			
Federal	35,109	31,187	35,021
State	6,669	10,424	8,603
	41,778	41,611	43,624
Total provision for income taxes	$41,705	$43,403	$42,825
Total income taxes paid	$870	$2,979	$1,756

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

In thousands	2013	2012	2011
Utility:			
Current	$(73)	$1,909	$(4,646)
Deferred	38,073	39,163	49,595
Deferred investment and energy tax credits	(271)	(350)	(422)
	37,729	40,722	44,527
Non-utility business segments:			
Current	—	(117)	3,846

Deferred	3,976	2,798	(5,548	)
	3,976	2,681	(1,702	)
Total provision for income taxes	$41,705	$43,403	$42,825	

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts for the two years ended December 31:

In thousands	2013	2012	
Deferred tax liabilities:			
Plant and property	$362,160	$322,527	
Regulatory income tax assets	56,183	60,253	
Regulatory liabilities	71,971	49,197	
Non-regulated deferred tax liabilities	47,516	43,824	
Total	$537,830	$475,801	
Deferred tax assets:			
Regulatory assets	$—	$(7,724	)
Unfunded pension and postretirement obligations	4,112	6,024	
Non-regulated deferred tax assets	—	(1,235	)
Alternative minimum tax credit carryforward	1,939	1,986	
Loss and credit carryforwards	45,351	32,997	
Total	51,402	32,048	
Deferred income tax liabilities, net	486,428	443,753	
Deferred investment tax credits	367	624	
Deferred income taxes and investment tax credits	$486,795	$444,377	

We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2013.

On December 17, 2010, President Obama signed into law the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, which allows 100% bonus depreciation for qualified property placed in service between September 9, 2010 through December 31, 2011. It also extended the 50% bonus depreciation deduction to qualifying property placed in service through 2012. On January 2, 2013, President Obama signed into law the American Taxpayer Relief Act of 2012, which extended 50% bonus depreciation under §168(k) through 2013 for modified accelerated cost recovery system (MACRS) property with a recovery period of 20 years or less.

The Company estimates that it has net operating loss (NOL) carryforwards of $113.0 million for federal taxes and $113.7 million for Oregon taxes at December 31, 2013. The NOL carryforwards will be carried forward to reduce our current tax liability in future years. We anticipate that we will be able to utilize the entire NOL carryforwards before they expire in 20 years for federal and 15 years for Oregon.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, we would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in our consolidated balance sheet. As of December 31, 2013, we had no reserves for uncertain tax positions.

As of December 31, 2013, the Company was under examination by the Internal Revenue Service for tax years 2009 through 2011, with resolution expected in 2014. The Company is also subject to examination for tax year 2012.

In 2012 the Company settled the Oregon Department of Revenue examination of tax years 2006 through 2009. This settlement resulted in an additional $0.2 million state tax expense, including interest, but that amount was offset by a corresponding refund claim with the state of California.

Interest and penalties related to any future income tax deficiencies are recorded within income tax expense in the consolidated statements of comprehensive income.

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	2013	2012
Utility plant in service	$2,585,901	$2,435,886
Utility construction work in progress	28,855	46,831
Less: Accumulated depreciation	827,380	789,201
Utility plant, net	1,787,376	1,693,516
Non-utility plant in service	297,330	296,781
Non-utility construction work in progress	6,653	6,510
Less: Accumulated depreciation	28,485	23,195
Non-utility plant, net	275,498	280,096
Total property, plant, and equipment	$2,062,874	$1,973,612

The weighted average depreciation rate was 2.8% for utility assets and 2.2% for non-utility assets in 2013, 2012, and 2011.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $296.3 million and $281.2 million at December 31, 2013 and 2012, respectively. These accrued asset removal costs are

reflected on the balance sheets as regulatory liabilities. See Note 2.

11. GAS RESERVES

Our gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet.

We entered into our agreements with Encana Oil & Gas (USA) Inc. (Encana) to develop and produce physical gas reserves. These agreements are intended to provide long-term gas price protection for our utility customers rather than serving as a source of gas supply. Encana began drilling in 2011 under these agreements, and gas, which is currently being produced from our working interests in these gas fields, is sold by Encana at then prevailing market prices, with revenues from such sales, net of associated production costs, credited to our cost of gas. The cost of gas, including a carrying cost for the net rate base investment, is part of our annual Oregon PGA filing, which allows us to recover our costs through customer rates in a manner previously approved by the OPUC. This transaction acted to hedge the cost of gas for approximately 6% of our gas supplies for the year ended December 31, 2013. The following table outlines our net gas reserves investment at December 31:

In thousands	2013	2012
Gas reserves, current	$20,646	$14,966
Gas reserves, non-current	140,573	92,179
Less: Accumulated amortization	18,575	7,486
Total gas reserves	142,644	99,659
Less: Deferred taxes on gas reserves	42,117	28,329
Net investment in gas reserves	$100,527	$71,330

Variable Interest Entity (VIE) Analysis

We concluded that the arrangement with Encana qualifies as a variable interest (VI) as our interest represents a minor portion of total extraction activities. Our investment is included on our balance sheet under gas reserves with our maximum loss exposure limited to our current 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	2013	2012
Investments in life insurance policies	$51,791	$51,439
Investments in gas pipeline joint ventures	14,048	14,216
Other	2,012	2,012
Total other investments	$67,851	$67,667

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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.

Equity Method Investments

Palomar, a wholly-owned subsidiary of PGH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH is owned 50% by NWN Energy, a wholly-owned subsidiary of NW Natural, and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

VIE Analysis

PGH is a development stage VIE. As of December 31, 2013, there were no changes to our VIE analysis and, as such, we continue to report Palomar under equity method accounting based on the determination that we are not the primary beneficiary of PGH's activities, as defined by the authoritative guidance related to consolidations, due to the fact that we have a 50% share and there are no stipulations that allow disproportionate influence over the entity. Our investment in PGH and Palomar are included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner.

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. When it is determined that 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, Palomar 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. Palomar 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.

Due to project scope changes in 2011, a portion of the assets were impaired and, as a result, we recorded a pre-tax charge of $1.3 million for our share of these costs at December 31, 2011. There have been no significant changes or impairments to the project since 2011. Our remaining equity investment was not impaired at December 31, 2013 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2013.

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 $13.2 million based on the current amount of our equity investment, net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as required.

13. DERIVATIVE INSTRUMENTS

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

We enter into these financial derivatives, up to prescribed limits, 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 optimization of our gas portfolio, which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement.

Notional Amounts

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

	At December 31,	
In thousands	2013	2012
Natural gas (in therms):		
Financial	389,225	395,820
Physical	552,500	398,250
Foreign exchange	$15,002	$13,231

PGA

Derivatives entered into by the utility for the procurement or hedging of natural gas for future gas years and prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate is set for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for either an 80% or 90% deferral of any gains and losses as regulatory assets or liabilities, with the remaining 20% or 10% recognized in current income. For the current gas year we have selected the 90% deferral option. In general, our commodity hedging for the current gas year is completed prior to the start of the upcoming gas year, and hedge prices are included in the Company's weighted-average cost of gas (WACOG) in the PGA filing. As of November 1, 2013, we reached our target hedge percentage for the 2013-14

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gas year, and these hedge prices were included in the PGA filing and qualified for regulatory deferral.

Unrealized and Realized Gain/Loss

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments. Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards.

In thousands	December 31, 2013 Natural gas commodity	December 31, 2013 Foreign exchange	December 31, 2012 Natural gas commodity	December 31, 2012 Foreign exchange
Benefit (expense) to cost of gas	$4,985	$(300)	$(5,850)	$65
Less:				
Amounts deferred to regulatory accounts on balance sheet	(4,964)	300	5,850	(65)
Total gain in pre-tax earnings	$21	$—	$—	$—

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.

We realized net losses of $11.0 million and $70.2 million for the years ended December 31, 2013 and 2012, respectively, from the settlement of natural gas financial derivative contracts. These realized losses were recorded as increases to the cost of gas.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of December 31, 2013 or 2012. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and portfolio diversification, we have not been subject to collateral calls in 2013 or 2012. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current financial swap and option contracts outstanding, which reflect unrealized gains of $5.4 million at December 31, 2013, we do not have any collateral demand exposure.

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

If netted by counterparty, our derivative position would result in an asset of $7.2 million and a liability of $2.5 million as of December 31, 2013. As of December 31, 2012, our derivative position would result in an asset of $5.6 million and a liability of $11.4 million.

We are exposed to derivative credit risk primarily through securing pay-fixed natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases 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 in order for them 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 utilize 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 utilize a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. We use the results of the model to establish earnings-at-risk trading limits. Our credit risk for all outstanding financial derivatives at December 31, 2013 currently does not extend beyond March 2016.

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, but we would expect such loss

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to be eligible for regulatory deferral and rate recovery, subject to prudence review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value

In accordance with fair value accounting, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation techniques include natural gas futures, volatility, credit default swap spreads and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at December 31, 2013. As of December 31, 2013 and 2012, the net fair value was an asset of $4.7 million and a liability of $5.8 million, respectively, using significant other observable, or level 2, inputs. We have used no level 3 inputs in our derivative valuations. We did not have any transfers between level 1 or level 2 during the years ended December 31, 2013 and 2012. 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 $5.1 million, $4.8 million and $5.4 million for the years ended December 31, 2013, 2012 and 2011, respectively. The following table reflects the future minimum lease payments due under non-cancelable leases at December 31, 2013. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, and computer equipment.

In thousands	Operating leases	Capital leases	Minimum lease payments
2014	$5,611	$462	$6,073
2015	5,530	196	5,726
2016	5,510	82	5,592
2017	5,506	12	5,518
2018	2,858	—	2,858
Thereafter	34,836	—	34,836
Total	$59,851	$752	$60,603

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, 2013:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2014	$60,692	$94,923	$3,739
2015	—	77,433	—
2016	—	66,146	—
2017	—	52,084	—

2018	—	42,263	—
Thereafter	—	216,995	—
Total	60,692	549,844	3,739
Less: Amount representing interest	20	113,437	—
Total at present value	$60,672	$436,407	$3,739

Our total payments for fixed charges under capacity purchase agreements were $98.2 million in 2013, $94.3 million in 2012, and $94.2 million in 2011. Included in the amounts were reductions for capacity release sales of $4.5 million for 2013, $4.2 million for 2012, and $3.1 million for 2011. 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

See Note 15 Environmental Matters 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. Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated. Unless there is an estimate within a range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely that changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives.

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In the 2012 Oregon general rate case, the new SRRM mechanism was approved to recover the Company's deferred environmental costs. The Commission ordered a separate docket to determine the prudence of deferred costs, the allocation of insurance proceeds, and an earnings test that would be applied to past and future deferred costs. In July 2013, all parties filed a settlement agreement with the OPUC to address how to apply the new mechanism. In November, the Commission rejected the settlement and ordered further proceedings. We have established a schedule with parties for 2014 and are working toward resolution of this matter.

In Washington, cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding. We annually review all regulatory assets for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets no longer meet the criteria for continued application

of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings in the period such determination is made.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Part I, Item 3 "Legal Proceedings"). In the complaint, NW Natural sought damages in excess of $50 million in losses it incurred through the date of the complaint, as well as declaratory relief for additional losses it expects to incur in the future. As of February 6, 2014, we had settled with all defendant insurance companies in this litigation. As a result of this settlement, the Company expects to receive additional payments aggregating approximately $102 million in 2014 related to the settlements. Such payments are to be made in the first and second quarters of 2014. Through December 31, 2013, we have received approximately $48 million. See Note 17 for additional information.

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	2013	2012	2013	2012
Portland Harbor site:				
Gasco/Siltronic Sediments	$1,278	$2,207	$37,954	$36,087
Other Portland Harbor	1,766	1,767	3,478	3,160
Gasco Upland site	11,010	18,722	39,508	5,028
Siltronic Upland site	763	637	406	379
Central Service Center site	85	140	248	396
Front Street site	1,274	993	122	—
Oregon Steel Mills	—	—	179	185
Total	$16,176	$24,466	$81,895	$45,235

The following table presents information regarding the total amount of cash paid for environmental sites and the total regulatory asset deferred as of December 31:

In thousands	2013	2012
Cash paid(1)	$98,817	$71,124
Total regulatory asset deferral(2)	148,389	121,144

(1) Includes $20.1 million reclassified to utility plant in 2013 associated with the water treatment station of which a portion was paid in 2012.

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

PORTLAND HARBOR SITE. The Portland Harbor is an EPA listed Superfund site that is approximately 11 miles long on the Willamette River and is adjacent to NW Natural's Gasco upland and Siltronic upland sites. We have been notified that we are a potentially responsible party to the Superfund site and we have joined with other potentially responsible parties (the Lower Willamette Group or LWG) to

develop a Portland Harbor Remedial Investigation/Feasibility Study (RI/FS). The LWG submitted a draft Feasibility Study (FS) to the Environmental Protection Agency (EPA) in March 2012 that provides a range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of costs estimated for various remedial alternatives for the entire Portland Harbor, as provided in the draft FS, is $169 million to $1.8 billion. NW Natural's potential liability is a portion of the costs of the remedy the EPA will select for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 potentially responsible parties. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability. We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediment 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 upland and

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Siltronic upland sites. NW Natural submitted a draft Engineering Evaluation/Cost Analysis (EE/CA) to the EPA in May 2012 to provide the estimated cost of potential remedial alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA range from $39.2 million to $350 million. We have recorded a liability of $39.2 million for the sediment clean-up, which reflects the low end of the EE/CA range, as well as costs for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

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

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

In May 2007, we completed a revised Remedial Investigation Report for the uplands portion and submitted it to ODEQ for review. We have recognized a liability for the remediation of the uplands portion of the site which is at the low end of the range of potential liability and the high end of the range cannot be reasonably estimated at this time.

In September 2013, we completed construction and placed into service 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 due to the uncertainty associated with the duration of running the water treatment station, which will be highly dependent upon the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

On October 28, 2013, the OPUC approved placing $19.0 million of capital costs associated with constructing a water treatment station at our Gasco environmental site into rates beginning November 1, 2013. These amounts are subject to refund, with interest, in the event the Commission determines, through a separate docket, that any of these costs were incurred imprudently. On February 13, 2014, NW Natural filed an all-party stipulation in the proceeding with the OPUC, which if approved would deem Gasco construction costs prudent and would also approve applying $2.5 million of insurance proceeds plus interest to reduce the Gasco costs included in rates beginning November 1, 2014.

Other sites. In addition to those sites above, we have environmental exposures at four other sites: Siltronic, Central Service Center, Front Street, and Oregon Steel Mills. Due to the uncertainty of the design of remediation, regulation, timing of the liabilities, and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites has been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated as of December 31, 2013.

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

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

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

Oregon Steel Mills site. See “Legal Proceedings,” below.

Legal Proceedings

NW Natural is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with certainty, including the matter described below, NW Natural does not expect 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 Oregon

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Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect that the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

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16. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

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

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

The adjustment impacted years 2003 through 2012 with a cumulative pre-tax decrease over that period of $5.6 million to regulatory assets and other income and expense. The revision decreased net income by $1.1 million and $0.9 million for the years ended December 31, 2012 and 2011, respectively. The cumulative decrease to January 1, 2011 retained earnings was $1.4 million as a result of the revision.

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

In thousands, except per share data	2012 Reported Balance	Adjust-ment	Adjusted Balance	2011 Reported Balance	Adjust-ment	Adjusted Balance
Other income and expense, net	$4,936	$(1,777)	$3,159	$4,523	$(1,411)	$3,112
Income before income taxes	103,959	(1,777)	102,182	107,280	(1,411)	105,869
Income tax expense	44,104	(701)	43,403	43,382	(557)	42,825
Net Income	59,855	(1,076)	58,779	63,898	(854)	63,044
Comprehensive income	58,364	(1,076)	57,288	62,702	(854)	61,848
Basic EPS	2.23	(0.04)	2.19	2.39	(0.03)	2.36
Diluted EPS	2.22	(0.04)	2.18	2.39	(0.03)	2.36

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

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

Total equity	733,033	(3,406)	729,627	714,488	(2,330)	712,158
Total liabilities and equity	2,818,753	(5,633)	2,813,120	2,746,574	(3,856)	2,742,718

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

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

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

17. SUBSEQUENT EVENT

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers. NW Natural alleged that the defendant insurance companies issued third party liability insurance policies to NW Natural and that the defendants had breached the terms of those policies by failing to reimburse and indemnify NW Natural for liabilities arising from environmental contamination at certain sites caused or alleged to be caused by its historical operations.

NW Natural sought damages in excess of $50 million in losses it had incurred through the date of the complaint, as well as declaratory relief for additional damages it expected to incur in the future. Settlements with certain of the defendant insurance companies resulted in payments received by NW Natural through December 31, 2013 of approximately $48 million.

In January and February 2014, the remaining defendant insurance companies agreed to settle all of NW Natural's claims. In 2014 the Company expects to receive additional payments aggregating approximately $102 million under settlement agreements signed in 2013 and 2014. Such payments are to be made in the first and second quarters of 2014. As a result of such settlements, the Company anticipates dismissal of the litigation in the second quarter of 2014.

The settlements are recognized in regulatory accounts with the treatment determined through the SRRM. We expect the open regulatory docket regarding SRRM to be resolved during 2014.

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NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

In thousands, except share data	Quarter ended March 31	June 30	September 30	December 31
2013				
Operating revenues	$277,861	$131,714	$88,195	$260,748
Net income (loss)	37,639	2,126	(8,233)	29,006
Basic earnings (loss) per share[1]	1.40	0.08	(0.31)	1.07
Diluted earnings (loss) per share[1]	1.40	0.08	(0.31)	1.07
2012				
Operating revenues	$309,639	$103,991	$87,501	$229,476
Net income (loss)[2]	40,284	1,227	(10,879)	28,147
Basic earnings (loss) per share[1][2]	1.50	0.05	(0.41)	1.05
Diluted earnings (loss) per share[1][2]	1.50	0.05	(0.41)	1.04

[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.
[2] Prior period balances have been adjusted for a prior period error identified during the first quarter of 2013. See Note 16 for reconciliation to amounts previously reported.

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
2013					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,518	$199	$—	$1,061	$1,656
2012					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,895	$1,130	$—	$1,507	$2,518
2011					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,950	$1,919	$—	$1,974	$2,895

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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, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 9(a).

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning our Board of Directors, its Committees and the Audit Committee financial expert contained in NW Natural's definitive Proxy Statement for the May 22, 2014 Annual Meeting of Shareholders is hereby incorporated by reference. The information concerning "Section 16(a) Beneficial Ownership Reporting Compliance" and "Corporate Governance" contained in our definitive Proxy Statement for the May 22, 2014 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2013	Positions held during last five years
Gregg S. Kantor	56	President and Chief Executive Officer (2009-); President and Chief Operating Officer (2007-2008); Executive Vice President (2006-2007); Senior Vice President, Public and Regulatory Affairs (2003-2006).
David H. Anderson	52	Executive Vice President and Chief Operating Officer (2014-); Executive Vice President Operations and Regulation (2013-2014); Senior Vice President and Chief Financial Officer (2004-2013).
Stephen P. Feltz	58	Senior Vice President and Chief Financial Officer (2013-); Assistant Secretary (2007-); Treasurer and Controller (1999-2013).
Margaret D. Kirkpatrick	59	Senior Vice President and General Counsel (2013-); Vice President and General Counsel (2005-2013).
Lea Anne Doolittle	58	Senior Vice President and Chief Administrative Officer (2013-); Senior Vice President (2008-); Vice President, Human Resources (2000-2007).
J. Keith White	60	Vice President, Business Development and Energy Supply/Chief Strategic Officer (2007-); Managing Director, Gas Operations and Wholesale Services (2005-2006); Managing Director and Chief Strategic Officer (2003-2005).
David R. Williams	60	Vice President, Utility Services (2007-); Director of Utility Operations, Districts and Managed Labor Relations (2004-2006).
Grant M. Yoshihara	58	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
C. Alex Miller	56	Vice President Regulation and Treasurer (2013-); Vice President, Finance and Regulation (2009-2013); Assistant Treasurer (2008-2013); General Manager of Rates and Regulatory Affairs (2002-2009).
MardiLyn Saathoff	57	Vice President Legal, Risk and Compliance (2013-); Deputy General Counsel (2010-2013); Chief Governance Officer and Corporate Secretary (2008-); Chief Compliance Officer and Assistant General Counsel, Tektronix, Inc. (2005-2008).
Brody J. Wilson	34	Controller (2013-); Acting Controller (2013); Accounting Director (2012-2013); Senior Manager, PriceWaterhouseCoopers LLP (2009-2012); Manager, PriceWaterhouseCoopers LLP (2007-2009).
David A. Weber	54	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 (November 2010 - January 2011); Managing Director of Information Services and Chief Information Officer (2005 - 2011); Director of Information Services and Chief Information Officer (2001-2005).

Each executive officer serves successive annual terms; present terms end on May 22, 2014. 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 22, 2014 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2013 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, 2013 (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)	152,007	n/a	443,198
LTIP Restricted Stock Units (Target Award)(1)(2)	50,972	n/a	443,198
LTIP Stock Options(2)	—	—	250,000
Restated Stock Option Plan	492,150	$42.89	—
Employee Stock Purchase Plan	26,191	35.69	95,993
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)(3)	1,326	n/a	n/a
Directors Deferred Compensation Plan (DDCP)(3)	55,253	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)(4)	134,711	n/a	n/a
Total	912,610		789,191

(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, 2013, the number of shares shown in column (a) would increase by 152,007 shares and the number of shares shown in column (c) would decrease by the same amount of shares.

(2) The aggregate 443,198 shares are available for future issuance under the LTIP as Restricted Stock Units, Performance Share Awards, or LTIP Stock Options. An additional 250,000 shares are available for LTIP Stock Option Issuance at December 31, 2013, but those additional shares are not available for issuance of LTIP Restricted Stock Units or Performance Share Awards.

(3) 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.

(4) 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.

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 22, 2014 Annual Meeting of Shareholders is incorporated herein by reference.

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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 22, 2014 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2013 and 2012 Audit Firm Fees" in the Company's definitive Proxy Statement for the May 22, 2014 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.

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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/ Gregg S. Kantor
Gregg S. Kantor
President and Chief Executive Officer
Date: February 28, 2014

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/ Gregg S. Kantor Gregg S. Kantor President and Chief Executive Officer	Principal Executive Officer and Director	February 28, 2014
/s/ Stephen P. Feltz Stephen P. Feltz Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 28, 2014
/s/ Brody J. Wilson Brody J. Wilson Controller	Principal Accounting Officer	February 28, 2014
/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 28, 2014
/s/ C. Scott Gibson C. Scott Gibson	Director	))

		)
/s/ Tod R. Hamachek	Director	)
Tod R. Hamachek		)
		)
/s/ Jane L. Peverett	Director	)
Jane L. Peverett		)
		)
/s/ Kenneth Thrasher	Director	)
Kenneth Thrasher		)

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NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Annual Report on Form 10-K
For the Fiscal Year Ended December 31, 2013

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 period ending June 30, 2008, File No. 1-15973).
*3b.	Bylaws as amended May 24, 2012 (incorporated herein by reference to Exhibit 3.1 to Form 8-K dated May 24, 2012, File No. 1-15973).
*4a.	Copy of Mortgage and Deed of Trust, dated as of July 1, 1946, to Bankers Trust and R. G. Page (to whom Stanley Burg is now successor), Trustees (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); and 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).
*4b.	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).
*4c.	Officers' Certificate dated June 12, 1991 creating Series A of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4e. to Form 10-K for 1993, File No. 0-994).
*4d.	Officers' Certificate dated June 18, 1993 creating Series B of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4f. to Form 10-K for 1993, File No. 0-994).
*4e.	Officers' Certificate dated January 17, 2003 relating to Series B of the Company's Unsecured Medium-Term Notes and supplementing the Officers' Certificate dated June 18, 1993 (incorporated herein by reference to Exhibit 4f.(1) to Form 10-K for 2002, File No. 0-994).
*4f.	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).
*4g.	Form of Unsecured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated October 4, 2004, File No. 1-15973).

*4h.	Gill Ranch Note Purchase Agreement, dated November 30, 2011, among Gill Ranch Storage, LLC and the parties listed thereto (incorporated herein by reference to Exhibit 4m. to Form 10-K for 2011, File No. 1-15973).
*4i.	Twenty-First Supplemental Indenture, providing, among other things, for First Mortgage Bonds, 4.00% Series Due 2042, dated as of October 15, 2012, by and between Northwest Natural Gas Company, Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), and Stanley Burg (Successor to R.G. Page and J.C. Kennedy) (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 26, 2012, File No.1-15973).
*4j.	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).

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4k.	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 Credit Agreement between Northwest Natural Gas Company and each financial institutions, effective as of December 20, 2013.
*10a	Carry and Earning Agreement (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2011, 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:

*10b.	Executive Supplemental Retirement Income Plan 2010 Restatement (incorporated herein by reference to Exhibit 10b. to Form 10-K for 2009, File No. 1-15973).
*10c.	Supplemental Executive Retirement Plan, effective September 1, 2004 restated 2011 (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2011, File No. 1-15973).
*10d.	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).
*10e.	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).
*10f.	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).
*10g.	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).
*10h.	

	Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10h. to Form 10-K for 2009, File No. 1-15973).
*10i.	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).
*10j.	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).
*10k.	Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated as of January 1, 2012 (incorporated herein by reference to Exhibit 10k. to Form 10-K for 2011, File No. 1-15973).

*10l.	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.(1)	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 (incorporated herein by reference to Exhibit 10n. to Form 10-K for 2011, File No. 1-15973).
*10o.	Form of Agreement to Recoupment Provisions of Executive Annual Incentive Plan, effective as of January 1, 2010 (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2009, File No. 1-15973).
*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.	Severance agreement dated December 19, 2008 between the Company and Gregg S. Kantor (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 23, 2008, File No. 1-15973).
*10r.	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 2013, File No. 1-15973)
*10s.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2011-2013) (incorporated herein by reference to Exhibit 10u. to Form 10-K for 2011, File No. 1-15973).
*10t.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2012-2014) (incorporated herein by reference to Exhibit 10v. to Form 10-K for 2011, File No. 1-15973).
*10u.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2013-2015) (incorporated herein by reference to Exhibit 10v. to Form 10K for 2012, File No. 1-15973).
10v.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2014-2016).
*10w.	Form of Consent dated December 14, 2006 entered into by each executive officer (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10x.	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 the Long-Term Incentive Plan (2013) (incorporated herein by reference to Exhibit 10aa. to Form 10-K for 2012, File No. 1-15978).
*10bb.	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 14, 2011, File No. 1-15973).
*10cc.	

	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)
*10dd.	Annual Incentive Plan for NW Natural Gas Storage, LLC, as amended February 2, 2012 (incorporated herein by reference to Exhibit 10cc. to Form 10-K for 2012, File No. 1-15973).
*10ee.	Long Term Incentive Plan for NW Natural Gas Storage, LLC (incorporated herein by reference to Exhibit 10dd. to Form 10-K for 2012, File No. 1-15973).

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*10ff.	Form of Change in Control Severance Agreement between the Company and an executive officer (incorporated herein by reference to Exhibit 10ee. to Form 10-K for 2012, File No. 1-15973).
101.	The following materials from Northwest Natural Gas Company Annual Report on Form 10-K for the fiscal year ended December 31, 2013, formatted in Extensible Business Reporting Language (XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.

*Incorporated herein by reference as indicated