NORTHWEST NATURAL GAS CO
Form 10-K
March 01, 2013

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, 2012
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 30, 2012, the registrant had 26,827,437 shares of its Common Stock outstanding. The aggregate market value of these 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 $1,261,935,437.

At February 22, 2013, 26,937,683 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 2013 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, 2012

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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 atmospheric pressure and 60 degrees Fahrenheit. One hundred thousand Btu's equal one therm.

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.

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 to meet peak demand, whether that capacity is used or not.

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, particularly during cold weather.

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

GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (GAAP): accounting principles generally accepted in the United States of America.

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.

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 utility investments funded by common stock equity.

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

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

THERM: the basic unit of natural gas measurement, equal to 100,000 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.

WEATHER NORMALIZATION: a 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.

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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;
- 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;
- outcomes and effects of litigation, regulatory actions, and other administrative matters;
- projected obligations under retirement plans;
- availability, adequacy, and shift in mix, of gas supplies;
- approval and adequacy of regulatory deferrals; and
- environmental, regulatory, litigation and insurance costs and recoveries.

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

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

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NORTHWEST NATURAL GAS COMPANY
PART I

ITEM 1. BUSINESS

OVERVIEW

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

BUSINESS MODEL

Our business model primarily consists of two core businesses: local gas distribution, referred to as our "utility" business segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and gas storage, referred to as our "gas storage" business segment, which serves utilities, gas marketers, electric generators, and large industrial users. The utility business represents approximately 90% of our consolidated assets and net income, while our gas storage business accounts for a majority of the remaining 10%. We also have other business and investment activities, which we aggregate and refer to as our "other" segment and which accounts for less than 1% of consolidated assets and net income. We refer to our “gas storage” and “other” business segments as “non-utility.”

Local Gas Distribution "Utility"
We are principally engaged in the distribution of natural gas in Oregon and southwest Washington, which involves the following activities:

- building and maintaining a safe and reliable pipeline distribution system;
- purchasing gas from producers and marketers;
- contracting for the upstream transportation of gas over pipelines from regional supply basins into our service territory;
- reselling gas commodity to customers subject to rates, terms and conditions approved by the Public Utility Commission of Oregon (OPUC) or by the Washington Utilities and Transportation Commission (WUTC); and
- transporting gas commodities owned by customers from an interstate pipeline connection, or city gate, to the customers' facilities for a fee.

Our exclusive service area as allocated to us by the OPUC includes a major portion of western Oregon, including the Portland metropolitan area, most of the Willamette Valley, and the coastal area from Astoria to Coos Bay. The Portland metropolitan area is the principal retail and manufacturing center in the Columbia River Basin and is a major port for trade with Asia.

We also hold certificates from the WUTC granting us exclusive rights to serve portions of three southwest Washington counties bordering the Columbia River. We provide gas service in 125 cities and neighboring communities in 15 Oregon counties, as well as in 16 cities and neighboring communities in three Washington counties.

We serve residential, commercial and industrial customers in these service areas. Industries 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 accounts for a significant portion of our utility revenues.

In these service areas, we have no direct competition from other natural gas distributors. However, each customer class (i.e. residential, commercial and industrial) is subject to indirect competition. For residential customers, we compete primarily with electricity, fuel oil, propane and renewable energy providers. We also compete with electricity, fuel oil, propane, and renewable energy for small to mid-size commercial customers. In the industrial and large commercial markets, we compete with all forms of energy, including competition from wholesale natural gas marketers. Competition among energy suppliers is based on price, efficiency, reliability, performance, market conditions, technology, legislative policy, and environmental impact.

At December 31, 2012, we had approximately 686,000 utility customers, consisting of 621,000 residential, 64,000 commercial and 1,000 industrial customers. Approximately 90% of our utility customers are located in Oregon, and 10% are located in Washington. On an annual basis, residential and commercial customers typically account for about 50% to 60% of our utility's total volumes delivered and about 80% to 90% of our utility margin, while industrial customers account for the remaining 40% to 50% of volumes and about 5% to 15% utility margin. The remaining 10% or less of utility margin is derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism and other service fees.

In 2012 we experienced a net increase in residential customers of 5,729 primarily from single- and multi-family new construction, and from the conversion of existing homes from oil, electric and propane. The net increase of all new customers added in 2012 was 6,398. This represents a 12-month growth rate of 0.9%, which is up slightly from 2011 but below historical growth rates due to the economy. We estimate that natural gas is in less than 60% of residential single-family dwellings in our service territory. With natural gas' price advantage, operating convenience, and environmental benefits over fuel oil, we believe there is the potential for continued growth in residential and commercial conversions for many years.

See Note 4 for information on the utility's assets and results of operations.

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Regulation and Rates

The utility is subject to regulation with respect to, among other matters, rates we charge to utility customers and systems of accounts by State commissions, which include the OPUC and WUTC, as well as the Federal Energy Regulatory Commission (FERC). Among other matters, the OPUC and WUTC also regulate NW Natural's issuance of securities.

In order to establish approved rates with the commissions, we file general rate cases and rate tariff requests periodically. It is through these requests that the commission approves our authorized return on equity (ROE), an overall rate of return on rate base (ROR), the utility's capital structure, and other revenue/cost deferral and recovery mechanisms, such as our Purchased Gas Adjustment (PGA), Weather Normalization Tariff, Decoupling, System Integrity Program (SIP), Pension Cost Deferral (Pension Balancing), and environmental Site Remediation and Recovery Mechanism (SRRM).

In addition, under our Mist interstate storage certificate with the 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. The last such filing was made in 2008. The next filing is due by December 2013.

The utility's most recent general rate case in Oregon was effective November 1, 2012 and its most recent general rate case in Washington was effective January 1, 2009. As a result of these most recent rate cases, 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[2]:		
PGA	X	X
Incentive Sharing	X	
Weather Normalization Tariff	X	
Decoupling	X	
SIP	X	
Pension Balancing	X	
SRRM	X	

[1]Although we do not have the same specific regulatory mechanisms in Washington, we do have approved regulatory deferral orders which allow us to defer certain costs for future recovery through the PGA or future general rate cases, such as our environmental cost deferral order.
[2]See additional details on each rate mechanism in Part II, Item 7, “Results of Operations—Regulatory Matters,” and “Gas Storage,” below.

In our most recent general rate case, the OPUC decided that several items would be resolved in separate proceedings, including the Commission's review of:

recovery of working gas inventory carrying costs; the definition of the earnings test and a prudence review under SRRM; pension cost recovery specifically related to prepaid pension assets; and the Commission's review of our revenue-sharing arrangement on the utility's interstate storage and asset management activities.

Authorized rates and allowed recovery mechanisms provide our utility business the opportunity to recover prudently incurred capital and operating costs from customers, while also earning a reasonable return on investment for investors. 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 generally 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.

The pass-through of gas commodity purchase costs in customer rates also means that for our industrial and large commercial customers, margin is not materially affected by whether we sell them gas commodity as part of the utility service or only provide them with utility transportation services because they purchase the gas commodity directly from a marketer or supplier.

In addition to being able to select sales or transportation only service from the utility, our industrial and large commercial customers may select between firm and interruptible service levels. These choices can positively or negatively affect margin. Rates for firm service generally have higher profit margins for the utility than interruptible service. Prices in the natural gas commodity markets, along with the availability of pipeline capacity to ship customer-owned gas, are among the primary factors that cause industrial customers to choose between sales and transportation service or between higher and lower levels of service.

Our industrial tariffs include terms which are intended to give us more certainty so that we can manage the level of gas supplies we will need to purchase in order to serve this customer group. These terms include an annual election cycle period, special pricing provisions for out-of-cycle changes, and the requirement that industrial customers on our annual PGA sales rate must complete the agreed upon term of their service before switching to a new service. In the case of customers switching out-of-cycle from transportation to sales service, the customer may be charged the incremental cost of gas supply in accordance with our regulatory tariffs.

We have designed custom transportation service agreements with several of our largest industrial customers. These agreements are primarily designed to provide transportation rates that are competitive with the customer’s alternative capital and operating costs of installing direct pipeline connections to upstream interstate pipeline system, which would allow them to bypass our local

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gas distribution system. These agreements generally prohibit bypass during their terms. Due to the cost pressures that confront a number of our largest customers competing in global markets, bypass continues to be a competitive threat. Although we do not expect a significant number of our large customers to bypass our system in the foreseeable future, we may experience further deterioration of margin associated with customers transferring to special contracts where pricing is specifically designed to be competitive with their bypass alternative.

Gas Supply

The utility's gas supply strategy is to secure sufficient supplies of natural gas to meet the needs of our customers and to hedge gas prices so that we can effectively manage costs, reduce price volatility and maintain a competitive advantage. We have a diverse portfolio of short-, medium- and long-term firm gas supply contracts that are supplemented with gas from storage facilities either owned by us or contractually committed to us during periods of peak demand.

To execute our strategy we forecast customer requirements by considering estimated load growth and sensitivity analyses based on factors such as weather variations and price elasticity effects.

We also employ a gas purchasing strategy that includes:

- diverse sources of supply;
- diverse portfolio of contract durations and types, including both physical and financial contracts;
- strategic use of gas storage facilities and capacity recall agreements; and
- a variety of gas cost management strategies

DIVERSITY OF SUPPLY SOURCES. We purchase our gas supplies primarily at liquid trading points to facilitate competition and price transparency. These trading points include the NOVA Inventory Transfer (NIT) point in Alberta, Canada (also referred to as AECO), Huntingdon/Sumas and Station 2 in British Columbia, Canada, and multiple receipt points in the U.S. Rocky Mountains. Currently, about 71% 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, but we continue to evaluate our long-term supply mix based on projections of gas production and pricing in the U.S. Rocky Mountain regions 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 regions will continue to track with broader U.S. market prices. 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 pipeline projects to increase capacity out of the U.S. Rocky Mountain region.

DIVERSE PORTFOLIO OF CONTRACT TYPES AND DURATIONS. Our diverse portfolio of firm gas supply contracts typically includes gas purchase contracts for:

- year-round baseload supply;
- additional baseload supply for the winter heating season;
- seasonal contracts where we have an option to call on additional supplies on a daily basis during the winter heating season; and
- daily or monthly spot purchases.

At December 31, 2012, we have contracts with gas suppliers for deliveries ranging from three months to three years, which provide for a maximum of 2.1 million therms of firm gas per day during the winter heating season and 0.6 million therms per day year-round. In addition, we have another 1.2 million therms per day of firm gas supplies whereby we can purchase supplies for delivery to our system during the winter heating season. During 2012, we purchased a total of 733 million therms under contracts with durations outlined in the chart below.

Contract Duration (primary term)	Percent of Purchases	
Long-term (one year or longer)	34	%
Short-term (more than one month, less than one year)	21	
Spot (one month or less)	45	
Total	100	%

We typically renew or replace our gas supply contracts with new agreements from existing and new suppliers. Aside from the asset management of our core utility gas supplies by an independent energy marketing company, no individual supplier provided more than 10% of our supply requirements. Firm year-round supply contracts have remaining terms ranging from one to three years. Currently, all firm gas supply contracts use price formulas tied to monthly index prices. See "Gas Cost Management Strategy—Asset management," below.

In addition to our year-round contracts, we continue to contract in advance for firm gas supplies to be delivered only during the winter heating season. During 2012, new short-term purchase contracts were entered into with 18 suppliers, which in addition to our year- round contracts provide for a total of up to 2.1 million therms per day. We intend to enter into new purchase contracts during 2013 for roughly the same volume of gas with existing or new suppliers, as needed, to replace contracts that will expire in 2013.

We also buy gas on the spot market as needed to meet utility customer demand. We have flexibility under the terms of some firm supply contracts, to purchase spot gas in lieu of the firm contract volumes thereby allowing us to take advantage of more favorable pricing on the spot market from time to time.

A small volume of gas is also purchased from a non-affiliated producer in the Mist gas field in Oregon. Current production supplies are less than 1% of our total annual purchase requirements. Production from these wells varies as existing wells are depleted and new wells are drilled.

STRATEGIC USE OF GAS STORAGE AND CAPACITY RECALL. We supplement our firm gas supply purchases with gas withdrawals from storage facilities we own or that are contractually committed to us. Gas is generally purchased and injected into storage during periods of low demand so that it can be withdrawn for use at a later time during

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periods of peak demand. In addition to enabling us to meet our peak demand, these facilities make it possible to lower the annual average cost of gas by allowing us to minimize our pipeline capacity demand costs and to purchase gas for storage during the summer months when gas prices are generally lower.

Underground storage. A portion of our daily and seasonal peaking supplies to core utility customers are from our underground gas storage facility in the Mist gas storage field. This facility has a maximum daily deliverability of 5.2 million therms and a total working gas capacity of about 16 Bcf, which includes the capacity reserved for core utility customers as well as the capacity used for non-utility service. Under our regulatory agreement with the OPUC, non-utility gas storage at Mist can be developed in advance of core utility customer needs, but it is subject to recall by the utility when needed to serve utility customers as utility demand increases. Storage capacity recalled by the utility is added to utility rate base at net book value and tracked into utility rates in the annual PGA filing immediately following the recall, so there is minimal regulatory lag in cost recovery. In May 2012, a total of 150,000 therms per day of Mist storage capacity that had previously been available for non-utility interstate services was recalled and committed to use for core utility customers. Similarly in May 2011, a total of 100,000 therms per day of Mist storage capacity was recalled for core utility customer use. There was no Mist recall in 2010. The core utility currently has 2.8 million therms per day of deliverability and approximately 10.0 Bcf of working gas capacity available at the Mist storage facility.

We also have contracts with Northwest Pipeline, a subsidiary of The Williams Companies, for firm gas storage at the Jackson Prairie underground facility near Chehalis, Washington, which provides us with daily firm deliverability of about 0.5 million therms and total seasonal capacity of about 1.1 Bcf. Separate contracts with Northwest Pipeline provide for the transportation of these storage supplies to our service territory. All of these contracts have reached the end of their primary terms, but we have exercised our renewal rights that allow for annual extensions at our option.

In addition, we also contract for underground storage service in Alberta, Canada for amounts totaling just under 2 Bcf. This supply will displace equivalent volumes of spot purchases in Alberta as it uses the same pipeline transportation for delivery from Alberta to our local gas distribution system. While this supply helps manage price risks, it does not add to our total peak day resources.

Liquefied Natural Gas (LNG) storage. We own and operate two LNG storage facilities in our Oregon service territory that liquefy gas for storage during off-peak months so that it is available for withdrawal during periods of peak demand. These two facilities provide a maximum combined daily deliverability of 1.8 million therms and a total seasonal capacity of 1.5 Bcf. In addition, we have a contract for firm gas storage from an LNG facility in Plymouth, Washington, which provides us with daily firm deliverability of about 0.6 million therms and total seasonal capacity of about 0.5 Bcf.

Capacity recall from transportation customers. We also have contracts with one electric generator and two industrial customers that together provide 390,000 therms per day of recallable pipeline capacity and supply.

GAS COST MANAGEMENT STRATEGY. The cost of gas sold to utility customers primarily consists of:

- purchase price paid to suppliers;
- charges paid to pipeline companies to store and transport gas to our distribution system; and
- gains or losses related to gas commodity hedge contracts, including our gas reserves contract, entered into in connection with the purchase of gas for core utility customers.

Recent developments in drilling technologies have increased access to gas supplies in shale gas formations around the U.S. and Canada, the current outlook for North American natural gas supplies is strong and is projected to remain this way well into the future.

We are charged pipeline transportation rates by Canadian pipelines and U.S. interstate pipeline transportation service providers. These rates periodically change when the Canadian pipelines and U.S. interstate pipelines file for rate change approval from the Canadian National Energy Board or FERC, as applicable. Settlement was recently reached on a Northwest Pipeline rate case and new rates went into effect beginning January 1, 2013. Pipeline transportation rate increases or decreases are generally passed on to our customers through annual PGA updates.

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 convert floating index prices in physical gas supply contracts to fixed prices (referred to as commodity price swaps);
- negotiating financial derivative contracts that 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);
- buying physical gas supplies at a set price and injecting it into storage for price stability;
- investing in gas reserves for longer term price stability; and
- using an asset management service provider to produce incremental revenues that are used to reduce our utility's net cost of gas.

Financial derivative instruments. We hedge a majority of our firm year-round supply contracts each year using financial derivative instruments as a key component of our gas purchasing strategy. Our financial hedge contracts make up a majority of our commodity price hedging activity, and these contracts are with a number of investment-grade credit counterparties, typically with credit ratings of AA- or higher. Under our financial hedge policy, we enter into commodity swaps, puts, calls and collars with terms generally ranging anywhere from one month to five years. See Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk—Credit Risk—Credit exposure to financial derivative counterparties."

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Gas reserves. We entered into agreements with Encana Oil & Gas (USA) Inc. (Encana) which provide us a long-term fixed price hedge that is backed with physical supplies. These agreements are intended to provide long-term price protection for our utility customers. Our investment in these gas field interests are rate base investments that are part of our annual Oregon PGA filing, which is subject to incentive sharing and 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 4% of our gas supplies for the year-ended December 31, 2012.

Asset management. We use our gas supply, storage and transportation flexibility to capture opportunities that emerge during the course of the year for gas purchases, sales, exchanges or other means to manage net gas costs. In particular, our Mist underground storage facility provides flexibility to manage net gas costs. In addition to maximizing the value of our gas storage and pipeline capacity, we contract with an independent energy marketing company that manages our unused 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's cost of gas, and generate incremental revenues from a regulatory incentive-sharing mechanism, which are included in our gas storage business segment.

GAS DISTRIBUTION OPERATIONS. 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;
- 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 prudently to minimize risks associated with regulatory review and cost recovery.

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 which integrates the Company's bare steel replacement, transmission pipeline integrity management, and distribution pipeline integrity management programs into a single program. In response to the recent pipeline incidents involving other companies, natural gas distribution businesses are likely to be subject to even greater federal and state regulation in the future. The "Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011" signed into law in early 2012, includes several new safety initiatives including:

- an analysis of the appropriateness of automatic or remote shut-off valves on new and replaced gas transmission lines;
- an evaluation of the benefits of expanding transmission integrity management regulations to additional pipelines; and
- requirements for operators to reverify the maximum allowable operating pressures for transmission pipelines.

We continue to work diligently with industry associations as well as federal and state regulators to ensure the safety of our system and ensure 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 program ultimately rests on whether we provide reliable service at a reasonable cost 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 20 years in our service territory.

Our projected sources of delivery for design day firm utility customer sendout total approximately 9.3 million therms. Of this total, we are currently capable of meeting over 60% 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 January 5, 2004, we experienced our current record firm customer sendout of 7.2 million therms, and a total sendout of 8.9 million therms, on a day that was approximately 9 degrees Fahrenheit warmer than the design day temperature.

We believe that our 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 (see further discussion of IRP below).

The following table shows the sources of supply that are projected to be used to satisfy the design day sendout for the 2012-2013 winter heating season:

Therms in millions			
Sources of utility supply	Therms	Percent	
Firm supply purchases	3.3	36	%
Mist underground storage (utility only)	2.7	29	
Company-owned LNG storage	1.8	19	
Off-system firm storage contracts	1.1	12	
Recall agreements	0.4	4	
Total	9.3	100	%

The OPUC and WUTC have IRP processes in which utilities define different growth scenarios and corresponding resource acquisition strategies in an effort to evaluate supply and demand resources, consider uncertainties in the planning process and the need for flexibility to respond to

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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 annual 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 filed our draft 2013 IRP with Washington in January 2013 and will file an IRP update in Oregon in May of 2013.

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 balancing of interests between 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:

- re-setting customer rates annually to reflect changes in forecasted gas costs for the upcoming year and differences between actual and forecasted gas costs from the prior year. See Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment";
- aligning customer and shareholder interests through the use of our PGA incentive sharing mechanism, weather normalization, decoupling, and gas storage sharing mechanisms. See Part II, Item 7, "Results of Operations—Regulatory Matters"; and
- periodic review of regulatory deferrals with state regulatory commissions and key customer groups.

Transportation of Gas Supplies

SINGLE TRANSPORTATION PIPELINE. 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. 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, "2013 Outlook—Strategic Opportunities—Pipeline Diversification".

PIPELINE TRANSPORTATION AGREEMENTS. We incur monthly demand charges related to our firm pipeline transportation contracts.

Our largest pipeline agreements are with Northwest Pipeline for firm transportation capacity providing us access to natural gas supplies in British Columbia and the U.S. Rocky Mountains by connecting us with Northwest Pipeline and GTN systems in Oregon. These and other contracts are multi-year contracts with expirations ranging from 2016 to 2044. We actively work with Northwest Pipeline and others to renew these contracts in advance of expiration and ensure gas transportation capacity is sufficient to meet our needs.

RATES GOVERNING TRANSPORTATION OF GAS SUPPLIES. FERC establishes rates for interstate pipeline transportation service under long-term agreements within the U.S., and Canadian authorities establish rates for service under agreements with the Canadian pipelines over which we ship gas.

Gas Storage

Our gas storage segment primarily consists of two underground natural gas storage facilities:

- NON-UTILITY MIST – the non-utility portion of our Mist gas storage facility near Mist, Oregon; and
- GILL RANCH – our 75% share of the Gill Ranch gas storage facility near Fresno, California.

Transmission pipeline capacity and natural gas production are relatively constant over the course of a year compared to the demand for natural gas, which fluctuates daily and seasonally. Therefore, natural gas storage facilities are needed to manage the flow and availability of gas supplies during periods of low demand so these supplies can be stored and delivered into markets during periods of high demand. We capitalize on the imbalance of supply and demand and price volatility for natural gas by providing our gas storage customers with the ability to store gas for resale or use in a higher value period. Our natural gas storage facilities allow us to offer customers “multi-cycle” storage service, which permits them to inject and withdraw natural gas multiple times a year, providing more flexibility to

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capture market opportunities. See Note 4 for more information on gas storage assets and results of operations.

Regulation and Rates

Our gas storage segment is subject to regulation with respect to, among other matters, rates, terms of service, and system of accounts established by the OPUC, WUTC and FERC with respect to the Mist facilities, and by the California Public Utilities Commission (CPUC) with respect to Gill Ranch. Gill Ranch has a tariff on file with the CPUC authorizing it to charge market-based rates for the storage services offered. FERC has approved maximum cost-based rates under our Mist interstate storage certificate. We are required to file with FERC either a petition for rate approval or a cost and revenue study 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”.

Facilities

MIST STORAGE FACILITY. We provide gas storage services to customers in the interstate and intrastate markets from our Mist gas storage facilities located in Columbia County, Oregon, near the town of Mist. The Mist field was converted to storage operations for our utility customers during the 1990s. 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 firm storage services in Oregon under an OPUC-approved rate schedule as an optional service to eligible non-residential utility customers.

GILL RANCH STORAGE FACILITY. Gill Ranch Storage, LLC (Gill Ranch), our subsidiary, has a joint project agreement with Pacific Gas and Electric Company (PG&E) to develop and own the Gill Ranch underground natural gas storage facility near Fresno, California. Currently, Gill Ranch is the sole operator of the facility. The facility began operations in the fourth quarter of 2010.

The Gill Ranch facility currently consists of three depleted natural gas reservoirs, twelve 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.

Gill Ranch is offering storage services to the California market at market-based rates, subject to regulation by the CPUC for certain activities including, but not limited to, service terms and operating conditions.

ASSETS. The following table highlights certain important design information about the Company’s non-utility gas storage assets.

	Storage Capacity (Bcf)	Withdrawal (MMcf/day)[3]	Injection (MMcf/day)[3]
Mist Storage[1]	6	243	97
Gill Ranch Storage[2]	15	488	240

[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 withdrawal rates.

Interstate Gas Storage

The Mist gas storage facility currently provides firm and interruptible gas storage services with related transportation services on the utility's system to and from Mist to interstate pipeline interconnections in order to serve customers in interstate commerce. The interstate storage services, and maximum rates for these services, are authorized and regulated by the FERC. The Interstate storage capacity has been developed as a non-utility investment by NW Natural in advance of core utility customers' requirements.

Gill Ranch storage facility is not currently authorized to provide interstate gas storage services.

Intrastate Gas Storage

The Mist gas storage facility provides intrastate gas storage services in Oregon under an OPUC-approved rate schedule that includes service eligibility and site-specific qualifications. The firm storage service rates, terms and conditions mirror our firm interstate storage service regulated by FERC, except that these customers are located and served in Oregon.

Gill Ranch provides intrastate 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.

Seasonality of Business

Generally, Mist gas storage revenues 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, and rates for firm service are primarily in the form of fixed monthly reservation charges and not affected by customer usage. However, there is seasonal variation with Mist storage capacity related to utility, and management of available surplus storage capacity and related transportation capacity can be managed under regulatory sharing agreements with the OPUC and WUTC. This temporary surplus capacity is quite often available during the spring and summer months when the demand for gas by utility customers is low. See "Asset Management" below.

Although we expect much of the storage revenue at Gill Ranch to be in the form of fixed monthly demand charges, total cash flows could be more seasonal in nature than the Mist storage facility. A significant portion of operating costs at Gill Ranch is related to compression. Because

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compression is used primarily for the injection of gas rather than for withdrawal, we expect power costs to be higher during the injection season.

Gas Storage Customers

For our 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.

Customer contracts for firm storage capacity at Gill Ranch are as long as 28 years in duration, but we expect Gill Ranch in the early years of operation to contract for terms mostly ranging from one to five years due to current market conditions. Gill Ranch currently has several storage customers, with the largest single contract accounting for approximately 13% of the facility's design capacity. 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. As such, we expect there to be less sensitivity to any single customer or group of customers for capacity at Gill Ranch. Current Gill Ranch customers provide energy related services, including natural gas production, marketing, and electric generation.

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 the Pacific Northwest region 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.

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 are also ongoing expansions and proposed new construction of storage capacity in northern California that could increase competition for Gill Ranch.

Storage Expansions

Mist Storage Facility. While the Pacific Northwest storage markets have been negatively impacted by lower gas prices and lack of price volatility, albeit less so than in California, we continue to plan for future expansion at Mist in anticipation of increased natural gas demand for electric generation in the Pacific Northwest. In 2012, a request for proposal (RFP) to provide additional electric generation was sent out by Portland General Electric (PGE). PGE's bid was recently selected for this project. We have an agreement to provide gas storage services to PGE as part of this project, subject to several conditions including NW Natural receiving regulatory approval. We believe the earliest timeframe for

completing the next expansion is 2016. We expect to begin working on detailed design and project scope during 2013, which will be followed by permitting and construction. The project will likely include the development of storage wells, a compression station, and additional pipeline facilities that would enable more storage expansions in the future.

Gill Ranch Storage Facility. 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 aggregate storage capacity of at least 40 Bcf, of which Gill Ranch would have the rights to at least an aggregate of 20 Bcf or 50% of the total estimated storage capacity.

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 business segment, except for amounts allocated to our utility pursuant to regulatory sharing agreements involving the use of utility assets. Pre-tax income from third-party asset management services is subject to revenue sharing with core utility customers. See Part II, Item 7, “Results of Operations–Business Segments - Gas Storage”

Other

We have non-utility investments and other business activities which are aggregated and reported as a business segment called “Other.” Although in the aggregate these investments and activities are not material, we identify and report them as a stand-alone segment because these investments and activities are not specifically part of our utility or gas storage segments. This segment primarily consists of:

- an equity method investment in a joint venture to build and operate a gas transmission pipeline in Oregon. See Part II, Item 7, “2013 Outlook—Strategic Opportunities—Pipeline Diversification”;
- a minority interest in other pipeline assets 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 the “Other” business segment. See Note 4 for summary information on this Other segment’s 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 response 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 continue to seek recovery of environmental costs through insurance and through customer rates, and we believe recovery of these costs is probable. Pursuant to the 2012 Oregon general rate case, environmental cost deferrals will be recovered under the new SRRM subject to a reduction for third-party insurance recoveries, a prudence review, and an earnings test that will be defined in a separate regulatory proceeding which is currently open. 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 both the insurance recovery 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" 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 potential 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 gas 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 continue to 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, 2012, the utility workforce consisted of 623 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.

At December 31, 2012, our subsidiaries had a combined workforce of 20 non-union employees. Our subsidiaries receive certain services from centralized operations at the utility, and as such the utility is reimbursed for those services pursuant to a Shared Services Agreement.

ADDITIONS TO INFRASTRUCTURE

We make capital expenditures in order to maintain and enhance the safety and integrity of our pipelines, terminals, storage facilities and related assets, to expand the reach or capacity of those assets, or improve the efficiency of our operations to pursue new business opportunities. 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, distribution system improvements and gas storage facilities. In 2013, utility capital expenditures are estimated to be between $115 and $130 million, and non-utility capital investments are estimated to be between $10 and $15 million. For the five-year period ending in 2017, capital expenditures for the utility are estimated to be between $600 and $700 million, while the amount for gas storage and other investments after 2013 will depend largely on future decisions about potential expansion opportunities in gas storage and pipeline projects.

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 (Code) 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. 3412.

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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 affect 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 return on equity, 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 business 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 the deferral of which 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 through the ratemaking process an authorized rate of return for our utility, 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 a review of our working gas inventory carrying costs, 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.

ECONOMIC AND MARKET RISK. Adverse economic and financial market conditions may have a negative impact on our financial condition and results of operations.

While the national and regional economy appears to be experiencing some recovery from the recent downturn, we cannot predict how robust the recovery will be, or whether it will be sustained. Continued or increased sluggishness in our regional economy, could result in low levels of new housing construction, conversions to natural gas, customer additions, and relatively higher levels of residential vacancies, lending restrictions, and personal and business bankruptcies, as well as reduced spending. All of these factors could all result in a decline in or sustained lower levels of natural gas consumption and customer growth, a slowing of collections from our customers, and higher levels of delinquent accounts receivable and bad debts, all of which could have a negative effect on our financial condition and results of operations.

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 are vigorously litigating 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 we are unable to recover these deferred costs in utility customer rates or through insurance, 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 stage on a regional cross-Cascades pipeline in Oregon. We may also engage in other business development projects in the future, including expansion of our gas storage facilities at Mist or Gill Ranch, or the investment in additional long-term gas reserves. 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 timeframe necessary for completing the project.

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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 including making operational decisions that could affect our costs and liabilities. In addition, other participants may withdraw from the project, 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, that 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, such as the “Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011” signed into law in early 2012. We expect there to be increased costs associated with compliance with this and similar 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 recent 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 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 the 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.

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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, 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 market, our gas distribution business competes primarily with suppliers of electricity, fuel oil, propane, and renewable energy providers. We also compete with suppliers of electricity, fuel oil and renewable energy providers for commercial applications. In the industrial market, we compete with suppliers of all forms of energy, including oil, electricity, renewable energy providers and, as it relates to sources of energy for electric power plants, coal and hydro. 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.

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 Business

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 a

10-year low. 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. A sustained decline in these prices 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 business 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

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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 piping system includes service pipelines, meters and regulators, and gas regulating and metering stations. Pipeline mains are located in municipal streets or alleys pursuant to valid franchise or occupation ordinances, in county roads or state highways pursuant to valid agreements or permits granted pursuant to statute, or on lands of others pursuant to valid easements obtained from the owners of such lands. We also hold all necessary 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 bare steel mains and services in the system by 2021.

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 associates 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 alleges that the defendant insurance companies issued third party liability insurance policies to NW Natural and that the defendants have 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 seeks damages in excess of $50 million in losses it has incurred to date, as well as declaratory relief for additional losses it expects to incur in the future.

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 trades for our common stock during the past two years were as follows:

	2012		2011	
Quarter Ended	High	Low	High	Low
March 31	$49.49	$44.40	$48.72	$43.92
June 30	48.56	43.90	46.40	43.57
September 30	50.16	46.04	46.77	39.63
December 31	50.80	41.01	48.98	42.52

The closing quotations for our common stock on December 31, 2012 and 2011 were $44.20 and $47.93, respectively.

As of February 22, 2013, there were 6,366 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	2012	2011
February 15	$0.445	$0.435
May 15	0.445	0.435
August 15	0.445	0.435
November 15	0.455	0.445
Total per share	$1.790	$1.750

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. However, the declaration and amount of future dividends depend upon our earnings, cash flows, financial condition and other factors.

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, 2012:

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
10/01/12-10/31/12	—	$—	—	—
11/01/12-11/30/12	3,114	42.75	—	—
12/01/12-12/31/12	—	—	—	—
Total	3,114	$42.75	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2012, 3,114 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, 2012, no

shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan (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, 2013 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, 2012, 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	2012	2011	2010	2009	2008
Operating revenues	$730,607	$828,055	$792,115	$988,055	$1,012,783
Net income	59,855	63,898	72,667	75,122	69,525
Earnings per share of common stock:					
Basic	$2.23	$2.39	$2.73	$2.83	$2.63
Diluted	2.22	2.39	2.73	2.83	2.61
Dividends paid per share of common stock	1.79	1.75	1.68	1.60	1.52
Total assets, end of period	$2,818,753	$2,746,574	$2,616,616	$2,399,252	$2,378,152
Total equity	733,033	714,488	693,101	660,105	628,373
Long-term debt	691,700	641,700	591,700	601,700	512,000

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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 activities for the years ended December 31, 2012, 2011, and 2010. 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), and
- NNG Financial Corporation (NNG Financial).

These statements also include our 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 investment in KB Pipeline. These entities make up our regulated local gas distribution business, our regulated gas storage businesses, and other regulated and non-regulated investments primarily in energy-related businesses. In this report, the term "utility" is used to describe our regulated gas distribution business (local distribution company), and the term "non-utility" is used to describe our gas storage businesses (gas storage) and other business segments. For a further discussion of our business segments, see Note 4.

In addition to presenting results of operations and earnings amounts in total, certain financial measures are expressed in cents per share, which 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 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

In 2012, we advanced the following core company initiatives:

- the Oregon general rate case was completed with key regulatory mechanisms renewed including our decoupling and weather normalization mechanisms and system integrity program. Several items in the case were delayed to separate dockets, and we will continue to work to resolve these items in 2013. Delayed items included interstate storage revenue sharing, working gas inventory, and a pension cost recovery mechanism. In addition, the earnings test for our new environmental Site Remediation and Recovery Mechanism (SRRM)

will be defined and a prudence review will be performed;

- safety initiatives moved forward including the launch of our emergency contact center dedicated exclusively to responding to emergency calls and the opening of a new industry-leading training facility; and
- customer growth and satisfaction continued to remain high with our growth rate at 0.9% for 2012 and J.D. Power and Associates ranked us in the top two utilities for customer satisfaction in the West for the ninth year in a row.

While we accomplished many goals in 2012, we look forward to further opportunities to safely provide service to our customers, work with regulators, and grow our business in 2013. See "2013 Outlook" below for more information.

Key financial highlights include:

In millions, except per share data	2012	2011	2010
Consolidated net income	$59.9	$63.9	$72.7
Consolidated earnings per share (EPS)	2.22	2.39	2.73
Utility margin	$344.5	$343.0	$346.1

Results for 2012:

- net income decreased primarily due to higher utility operations and maintenance, and depreciation expenses, as well as a one-time tax charge resulting from the Oregon general rate case;
- gas storage income increased primarily due to higher revenues reflecting additional capacity at our Gill Ranch gas storage facility; and
- utility margins increased primarily due to a $7.4 million net charge in 2011 related to a utility tax law change in Oregon, as well as residential and commercial customer growth, partially offset by a decrease in margin due to timing differences from the new billing rate structure resulting from the Oregon general rate case and the effects of warmer weather.

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

2013 OUTLOOK

With increased domestic supply of natural gas and lower prices, 2013 affords many opportunities for the natural gas industry and NW Natural. We remain committed to providing safe, reliable gas service to customers while growing our core businesses and exploring additional natural gas service needs and markets. Safety for our customers, employees, and communities is at the center of our activities.

GROW CORE BUSINESSES. Our primary businesses are utility and gas storage. In the utility, we continue to leverage our resources to provide natural gas services to our residential, commercial, and industrial customers. In particular, we will continue working with industrial customers to convert legacy oil heating systems to natural gas. In our gas storage business, we will focus on maximizing our storage capacity and optimizing revenue opportunities. We believe that investing in operating efficiencies and marketing

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opportunities for our core businesses positions us well for growth now and into the future.

ENSURE SAFETY. Safety is at the core of everything we do. We strive to provide our employees industry-leading safety training facilities, effective safety policies, procedures, and equipment, and foster a work environment that emphasizes safety in all areas. Maintaining a safe infrastructure and effective emergency response program is key to providing safe and reliable natural gas service to our customers. That is why we continue to focus on and invest in our system integrity program (SIP), emergency response system, training facilities and programs, and pipeline and system improvements.

ENHANCE STRATEGIC POSITION. The decline in natural gas prices and abundance of supplies creates opportunities for our utility business as we leverage natural gas' competitive price advantage. Our gas storage facilities are challenged by current market conditions, but we are strategically positioning ourselves to quickly respond to increasing market demand as the economy improves or gas prices become more volatile. Together, our businesses are competitively positioned to meet growing market demands.

ADVANCE KEY PROJECTS. We seek to create shareholder value by innovatively addressing the needs of our customers, employees, and the communities we serve while addressing economic, regulatory, and environmental challenges. To that end, we are advancing key business projects such as key rate mechanisms, pursuing storage development opportunities at Mist, and evaluating opportunities to create value and improve our Gill Ranch operations and revenues. We also continue to pursue regional solutions for reliable and safe energy needs through our investment in natural gas cross-Cascades pipeline infrastructure.

EXPLORE NEW SERVICE OPPORTUNITIES. We believe our utility business is strategically and competitively positioned with the decline in natural gas prices and the abundance of supplies. Natural gas is competitively priced in the energy market and compliments wind and solar renewable energy options as a reliable, on-call, electric generation resource. Therefore, we will be exploring new opportunities to serve customers with natural gas such as gas storage for wind following electric generation plants and natural gas for the vehicle transportation fuel market. We are also investigating expanded service offerings for our existing utility customers to ensure customer needs are met. We remain committed to continuous improvement and providing innovative and high quality service.

Issues, Challenges and Performance Measures

ECONOMY. The local, national, and global economies continued to show signs of weakness during 2012 and have impacted utility customer growth, business demand for natural gas and market prices for gas storage. Our utility's customer growth rate was 0.9% in 2012, compared to growth of 0.8% in 2011 and 0.9% in 2010. The local economy is beginning to show signs of a slow recovery as unemployment rates in our region dropped from approximately 9% in 2011 to about 8% at the end of 2012, and industrial gas use increased in 2012 by 1% over 2011. We believe our utility is well positioned to continue adding

customers and to serve increasing industrial demand as the economy recovers 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. In addition, environmental initiatives that favor lower carbon emissions and lower cost energy alternatives, such as natural gas, could increase demand for our services in the future.

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

Our utility's annual Purchased Gas Adjustment (PGA) mechanisms in Oregon and Washington, combined with our gas price hedging strategies, enable us to reduce earnings exposure for the Company and secure lower gas costs for our customers. See “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” below.

We typically hedge gas prices on approximately 75% of our utility's annual sales requirement based on average weather, including both physical and financial hedges. We entered the 2012-13 gas year (November 1, 2012 – October 31, 2013) hedged at approximately 75% of our forecasted sales volumes, including 47% in financial swap and option contracts and 28% in physical gas supplies. The physical hedges consisted of a combination of gas inventories in storage, local production from the Mist area, and production from gas reserves. For further discussion of gas reserves, see "Strategic Opportunities—Gas Reserves" and "Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves" below.

In addition to the amount of gas hedged for the current gas contract year, as of December 31, 2012 we are also hedged at approximately 22% for the 2013-14 gas year and between 8% and 24% for annual requirements over the following five gas years. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather and economic conditions. Also, our storage inventory levels may increase or decrease based on storage expansion, storage contracts with third parties, or storage recall by the utility.

Although less expensive and more stable gas prices provide opportunities to manage costs for our utility customers, they also present challenges for our gas storage businesses by lowering the price of, and reducing the demand for, storage services. Consequently, our ability to sign longer-term storage contracts with customers at favorable prices affects our financial results. However, if there is an increase in demand for natural gas and/or a decrease in drilling activity, there may be upward pressure on gas prices or price volatility which may result in increased demand and prices for storage services. In the short-term, we strive to find opportunities for increasing revenues, lowering costs and developing 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 development of remediation solutions approved by regulatory agencies, actual costs could vary significantly from our loss estimates. As a regulated utility, we have been allowed to defer certain costs pursuant to regulatory actions. In our general rate case, the Public Utility Commission of Oregon (OPUC) approved our recovery of costs from environmental site remediation subject to certain conditions as noted in "Results of Operations—Regulatory Matters—Rate Mechanisms" below.

We are pursuing recovery from insurance policies through litigation 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, demonstrate that costs were prudently incurred, and the impact of any earnings test the OPUC is expected to adopt in a subsequent proceeding. Cost recovery and carrying charges on amounts charged to Washington customers will be determined in a future proceeding. Based on these future proceedings, recovery may vary significantly from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable. See Note 15.

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 may drive 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 greenhouse gas releases. While our CO2 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. In order to deal with the challenges affecting our businesses, we annually review and update our strategic plan to map out a course for the next several years. Our plan includes strategies for:

- growing our utility services and operations;
- exploring new service opportunities in the natural gas industry;
- optimizing and growing our non-utility gas storage businesses;
- investing in natural gas infrastructure as needed to support the energy needs of our region; and
- maintaining a leadership role in the gas utility industry by advancing long-term energy policies.

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

- earnings per share growth;
- utility margin;
- return on equity (ROE); and
- various other operational metrics.

Strategic Opportunities

SAFETY, RELIABILITY, AND SERVICE. We are committed to customer and employee safety, operational effectiveness, service quality, and capitalizing on our competitive position. Therefore, we have several ongoing initiatives designed to improve the quality and integrity of our pipeline infrastructure, and have upgraded several facilities to enhance business continuity, employee training and safety, productivity, and energy efficiency. In addition, we opened a separate emergency contact center in 2012, which increased our ability to effectively respond to emergencies. Our initiatives in 2013 will further enhance our commitment to safety. The Company has increased staffing levels in the areas of pipeline safety, emergency response, regulatory compliance, field training, and customer service to respond to new federal pipeline safety legislation and system integrity requirements as well as customer expectations for service responsiveness.

GAS STORAGE. We own and operate two underground gas storage facilities—the Mist facility in Oregon and the Gill Ranch facility near Fresno, California. Storage operations benefit from seasonal swings in commodity pricing and market volatility. Our storage facilities position us to capitalize on rising demand for natural gas, higher gas prices or increased market volatility. Currently natural gas prices remain relatively low and stable; however, if there is an increase in demand for natural gas and/or a decrease in drilling activity, there may be upward pressure on gas prices and price volatility may return. We have the ability to expand both facilities beyond their current capacities.

The Pacific Northwest storage market is also impacted by lower gas prices and lack of gas price volatility, although less than California because there are fewer regional competitors. Nevertheless, we continue to plan for expansion at Mist in anticipation of increased natural gas demand for energy generation in the Pacific Northwest. In 2012, a request for proposal (RFP) to provide additional electric generation was sent out by Portland General Electric (PGE). PGE's bid was recently selected for this

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project. We have an agreement to provide gas storage services to PGE as part of this project, subject to several conditions including NW Natural receiving regulatory approval.

In addition, we estimate that the current Gill Ranch storage facility could support an additional 20 Bcf of storage capacity, bringing the total storage capacity to 40 Bcf, of which our rights would give us at least an additional 5 Bcf or ownership of a total of approximately 20 Bcf. An expansion at the Gill Ranch storage facility would require certain infrastructure modifications, but no further expansion of our gas transmission pipeline. See Note 4 for more information on our current gas storage facilities.

PIPELINE DIVERSIFICATION. Currently, our utility operations and gas storage operations at Mist depend on a single bi-directional interstate transmission pipeline to ship gas supplies to customers. This is why we continue to work with regulators and utilities in the Pacific Northwest to advance a new integrated, regional cross-Cascades pipeline through our Palomar investment.

The proposed pipeline would be regulated by the Federal Energy Regulatory Commission (FERC). Palomar intends to file an application with FERC for a pipeline delivering gas from the GTN pipeline near Madras in central Oregon to a NW Natural hub near Molalla, Oregon. The application will be filed after NW Natural has completed resource plans and Palomar has conducted a new open season to obtain commercial support for the pipeline. The approval and timing of potential construction of the pipeline will depend on the project being competitive with alternative Pacific Northwest pipeline projects, obtaining regulatory permits, and garnering the necessary commercial support from shippers. See Note 12 for further discussion.

GAS RESERVES. In addition to hedging gas prices with financial derivative contracts, we entered into an agreement with Encana Oil & Gas (USA) Inc. (Encana) in 2011 to hedge a portion of our Oregon utility customers' cost of gas over 30 years through working interests in gas leases. These working interests are in a gas field located in Sublette County, Wyoming. During the first 10 years of the contract, we forecast the volumes of gas to be produced under the gas reserves agreement as sufficient to hedge approximately 8% to 10% of the average annual utility gas supply requirements. The gas reserves transaction is expected to hedge approximately 8% of our utility gas supply for the 2012-13 gas year. We receive certain federal tax deductions for drilling costs incurred under our gas reserves agreements. The timing of when we realize these federal tax benefits has been affected by net operating losses for tax purposes, which will be carried forward to reduce our current tax liability in future years. We continue to evaluate additional investments in gas reserves as part of our gas hedging strategy. See "Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves" below.

CONSOLIDATED EARNINGS AND DIVIDENDS

Consolidated Earnings
Consolidated highlights include:

In millions, except EPS data	2012		2011		2010	
Net income	$59.9		$63.9		$72.7	
EPS	$2.22		$2.39		$2.73	
Return on equity	8.3	%	9.1	%	10.7	%

2012 COMPARED TO 2011. The primary factors contributing to the $4.0 million decrease in consolidated net income were:

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- 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 business segment.

2011 COMPARED TO 2010. The most significant factors contributing to the $8.8 million decrease in consolidated net income were:

- a $7.2 million net charge against utility margin taken in 2011, plus the $7.7 million of utility margin revenues accrued in 2010, related to the repeal of Oregon's legislative rule on utility income taxes;
- a $5.4 million increase in general taxes, primarily due to a $5.2 million refund of utility property taxes received in 2010, partially offset by a $0.9 million decrease in other taxes at the utility, and a $1.3 million increase in property and other taxes at Gill Ranch;
- a $4.9 million increase in depreciation and amortization expense, due to a $1.2 million increase at the utility and a $3.7 million increase at Gill Ranch; and
- a $4.3 million increase in operations and maintenance expense, primarily due to a $3.2 million increase at Gill Ranch reflecting first-year operating expenses.

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Partially offsetting the above factors was:

- an $11.3 million increase in utility margin attributable to an increase in customers gas use, reflecting gains from colder weather, customer growth and a slight increase in industrial demand; and a $6.1 million decrease in income tax expense related to lower taxable income.

Dividends

Dividend highlights include:

Per common share	2012	2011	2010
Dividends paid	$1.79	$1.75	$1.68

The Board of Directors declared a quarterly dividend on our common stock of 45.5 cents per share, payable on February 15, 2013, reflecting an indicated annual dividend rate of $1.82 per share.

RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

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

GAS STORAGE. Our gas storage business is subject to regulation with respect to, among other matters, issuance of securities and systems of accounts set by the OPUC, California Public Utilities Commission (CPUC), and FERC. The OPUC and FERC regulate intrastate and interstate storage services, respectively, under a maximum cost of service model which allows for storage prices to be set at or below the cost of service as approved by each agency in the last regulatory filing. The CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace. In 2012, approximately 54% of our storage revenues were derived from FERC and Oregon regulated operations and approximately 46% from California operations.

General Rate Cases

OREGON. Our most recent general rate case in Oregon was completed in 2012, and in it the OPUC authorized rates to customers based on an ROE of 9.5% and an overall rate of return of 7.78% with a capital structure of 50% common equity and 50% long-term debt. These customer rates went into effect on November 1, 2012, with annual revenue requirements increasing by $8.7 million or 1.2%. However, this increase included the recovery of amounts that had previously been deferred through the Company's decoupling mechanism of about $15 million. As a result, the overall effect on the Company was a decline in utility margin of approximately $6 million on an annualized basis.

The following items were postponed by the Commission:

- the request to include prepaid pension assets in rate base and allow a return on and recovery of the asset was denied; however, the OPUC indicated in the order that it will open a docket to review the treatment of pension expense on a general, non-utility-specific basis. A docket has been opened and until a conclusion is reached, the OPUC has authorized us to continue to collect and defer pension costs as we have historically, as outlined below;

- the existing arrangement we use to share revenues with customers from our Mist interstate storage operations and optimization services was continued, but a new docket will be opened to review the sharing arrangement; and
- the use of a new process to determine the appropriate amounts of working gas inventory that we earn a return on, and its corresponding rate of return. Included in the rate decrease effective November 1, 2012 was a reduction in margin of about $4 million related to working gas inventory, which we have been authorized to defer pending the outcome in a new docket.

In addition, to the items above, the earnings test for our new SRRM will also be defined in a separate proceeding and a prudence review will be performed. A decision on these items is expected in 2013, with the working gas inventory decision expected to be applied retroactively to November 1, 2012.

WASHINGTON. Our most recent general rate case in Washington was in 2008, and in it 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, with annual revenue requirements increased by $2.7 million or 3%.

FERC JURISDICTION. 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. Our most recent filing of a cost and revenue study was in April 2008. As a result of that proceeding, the current maximum cost-based rates for our interstate gas storage services were approved by FERC, with maximum rates unchanged from prior levels approved by FERC in 2005. In addition, we made a filing in December 2008 to obtain FERC approval to revise the depreciation rates associated with Mist assets used to derive the cost-based interstate storage rates. These new depreciation rates were designed to match the depreciation rates for the same type of assets approved under state regulation. We did not make any changes to the previously approved maximum rates, and

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FERC approved the depreciation rate filing in May 2009. We are required to make our next cost and revenue study filing at FERC on or before December 11, 2013.

CALIFORNIA. Gill Ranch is authorized by the CPUC to charge market-based rates for the intrastate storage services offered to customers in California.

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, and the production of gas reserves, interstate pipeline demand costs, the application of temporary rate adjustments, which amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

In October 2012, the OPUC authorized PGA rate changes effective November 1, 2012. The effect of these rate changes was to decrease the average monthly bills of Oregon residential customers by about 7%. This was our fourth consecutive year of PGA rate decreases, and cumulatively our Oregon utility residential customer bills have declined 26% since 2008.

In October 2012, the WUTC PGA rates were allowed to go into effect on November 1, 2012. However, the WUTC also ordered a continuing review of all Washington gas companies' PGA filings. We do not anticipate any changes to our PGA rates as filed; however, if the WUTC were to find any of our hedges to be imprudent, rates could be adjusted as a result of this review. The effect of the ordered PGA rates was to decrease average monthly bills of Washington residential customers by about 8%. This was our fourth consecutive year of PGA rate decreases in Washington, and cumulatively our Washington utility residential customer bills have declined 34% since 2008.

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. See “Customer Credits for Gas Cost Incentive Sharing” below for a discussion of our utility’s early refund to customers of deferred gas cost savings from November 1, 2011 through March 31, 2012.

In addition to the gas cost incentive sharing mechanism, 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 2010-2011, 2011-2012 and 2012-2013 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2010 and 2011, the ROE threshold after adjustment for long-term interest rates was 11.02% and 10.92%, respectively. We refunded $0.2 million to customers based on the 2010 utility earnings test, and based on the recently approved PGA, we are refunding $0.7 million to customers based on the 2011 utility earnings test. We do not expect to be subject to a refund for the 2012 earnings test year.

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 costs, revenues, and volumes expected, and any variances between forecasted and actual results are subject to our PGA incentive sharing in Oregon, up to a maximum variance of $10 million of which 10% (or $1 million maximum) would be recognized in current income. Annual variances in excess of $10 million, both negative and positive, are deferred and passed through to customers in full in future rates.

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. The conservation tariff 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 next 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

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warmer than average. The mechanism is applied to bills between December and 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. Customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of December 31, 2012, 9% had opted out. We do not have a weather normalization mechanism approved for Washington customers, which account for about 10% of our utility volumes and revenues. See “Business Segments—Local Gas Distribution "Utility" Operations” below.

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

SYSTEM INTEGRITY PROGRAM. Since 2002, various laws requiring minimum standards for integrity management programs and SIPs for natural gas 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 has approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program, SIP, and the related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) and provided a two-year extension 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 recovery after the first $3.3 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. The SIP allows recovery of costs incurred through 2014. We do not have any special accounting or rate treatment for our SIP costs incurred in the state of Washington.

ENVIRONMENTAL COSTS. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue a carrying cost on amounts deferred, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and accrual of carrying costs was extended through January 2012. In January 2013, we filed a request with the OPUC to continue our deferral of these environmental costs. See Note 15 for further discussion of our regulatory and insurance recovery of environmental costs.

A new SRRM, authorized in the 2012 Oregon general rate case, allows the Company to recover prudently incurred environmental site remediation costs. This SRRM will allow recovery of one-fifth of the Company's current and future deferred expenses each year in rates on a rolling basis until all such expenses are recovered, subject to an annual prudence review. Recovery of these incurred costs will also be subject to an earnings test, which has not yet been defined but a docket has been opened on the matter. This earnings test could include deadbands, or other limitations based on our earnings in a year, which could reduce the amounts we are allowed to recover. At this time, the OPUC has not ruled on how this separate earnings test will function.

The WUTC has also authorized the deferral of environmental costs, if any, that are appropriately charged to Washington customers. This order was effective January 26, 2011 with cost recovery and a carrying charge to be determined in a future proceeding. A decision regarding allocation of costs to each state is pending. See Note 15 for further discussion of our regulatory and insurance recovery of environmental costs.

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. 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 COST INCENTIVE SHARING. For the period between November 1, 2011 and March 31, 2012, our actual gas costs were significantly lower than the gas costs currently embedded in customer rates. As a result, our PGA incentive sharing mechanism recorded 90% of gas cost savings during this period, attributed to Oregon customers, and 100% of the savings attributed to Washington customers, to a regulatory liability account for credit to customers. Ordinarily, these credits would be refunded in customer rates starting in November under the next year's PGA filing, but in April 2012 the

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Company requested regulatory approval to immediately refund $35.1 million and $4.2 million to our Oregon and Washington customers, respectively, through billing credits. These credits were approved, and we began crediting these amounts to customer bills in June of 2012. See “Purchased Gas Adjustment,” above.

CUSTOMER CREDITS FOR GAS STORAGE SHARING. As we are able and get approval from the OPUC and WUTC, we credit amounts to both Oregon and Washington customers as part of our regulatory incentive sharing mechanism related to gas storage and asset management services of pipeline capacity and gas storage at Mist. Generally amounts are credited to Oregon customers in June and credits are given to customers in Washington through their annual PGA filing in November. See “Business Segments—Gas Storage” below.

The following table presents the credits to customers:

In millions	2012	2011	2010
Oregon utility customer credit	$9.2	$12.5	$11.0
Washington utility customer credit	0.8	0.9	1.2

Business Segments - Local Gas Distribution "Utility" Operations

Our utility margin results are largely affected by customer growth and, to a certain extent, by changes in volume due to weather and customers’ gas usage patterns because a significant portion of our utility margin is derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff, 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.

Utility segment highlights include:

Dollars and therms in millions, except EPS data and as otherwise noted	2012	2011	2010
Utility net income	$55.1	$60.5	$66.3
EPS - utility segment	$2.05	$2.26	$2.49
Gas sold and delivered (in therms)	1,112	1,152	1,062
Utility margin(1)	$344.5	$343.0	$346.1

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

2012 COMPARED TO 2011. The primary factors contributing to the $5.4 million or $0.21 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 return on equity.

- 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.

2011 COMPARED TO 2010. The primary factors contributing to the decrease in our utility segment net income of $5.8 million, or $0.23 per share, were as follows:

- a reduction in utility margins of $14.9 million related to the repealed Oregon legislative rule SB 408 on utility income taxes paid, including a $7.4 million write-off in 2011 plus a $7.7 million revenue accrual recognized in 2010; and
- a net gain of $6.1 million recognized in 2010 related to a refund of property taxes plus accrued interest from a favorable tax ruling.

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These factors were partially offset by:

- increases in residential and commercial customer utility margins of $11.3 million, including the effects of weather normalization and decoupling mechanisms;
- a slight gain in industrial customer utility margins of $0.2 million; and
- an increase in gas cost incentive sharing of $0.5 million.

Total utility volumes sold and delivered in 2011 increased 9% over 2010 primarily due to the impact of colder weather on residential and commercial use.

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UTILITY MARGIN TABLE. The following table summarizes the composition of utility gas volumes and revenues for the years ended December 31, 2012, 2011, and 2010. Certain prior year amounts in the following table have been reclassified to conform with the current year's presentation. These reclassifications reflect amounts moved into residential, commercial, and industrial categories where such amounts were specifically attributable to that customer category. Utility volumes and margin in total were not affected by these reclassifications.

In thousands, except degree day and customer data	2012	2011	2010	Favorable/(Unfavorable) 2012 vs. 2011	2011 vs. 2010
Utility volumes - therms:					
Residential and commercial sales	637,885	681,621	596,543	(43,736)	85,078
Industrial sales and transportation	473,884	470,733	465,426	3,151	5,307
Total utility volumes sold and delivered	1,111,769	1,152,354	1,061,969	(40,585)	90,385
Utility operating revenues - dollars:					
Residential and commercial sales	$642,337	$744,355	$696,439	$(102,018)	$47,916
Industrial sales and transportation	70,020	81,313	82,300	(11,293)	(987)
Regulatory adjustment for income taxes paid[1]	—	(7,162)	7,721	7,162	(14,883)
Other revenues	5,935	3,713	4,173	2,222	(460)
Less: Revenue taxes	18,430	20,741	19,991	(2,311)	750
Total utility operating revenues	699,862	801,478	770,642	(101,616)	30,836
Less: Cost of gas	355,335	458,508	424,494	(103,173)	34,014
Utility margin	$344,527	$342,970	$346,148	$1,557	$(3,178)
Utility margin:[2]					
Residential and commercial sales	$306,382	$315,688	$304,371	$(9,306)	$11,317
Industrial sales and transportation	28,586	28,635	28,451	(49)	184
Miscellaneous revenues	4,452	4,875	4,658	(423)	217
Gain from gas cost incentive sharing	3,811	2,107	1,594	1,704	513
Other margin adjustments	1,296	(1,173)	(647)	2,469	(526)
Regulatory adjustment for income taxes paid[1]	—	(7,162)	7,721	7,162	(14,883)
Utility margin	$344,527	$342,970	$346,148	$1,557	$(3,178)
Customers - end of period:					
Residential customers	621,399	615,670	610,598	5,729	5,072
Commercial customers	63,619	62,948	62,489	671	459
Industrial customers	923	925	910	(2)	15
Total number of customers - end of period	685,941	679,543	673,997	6,398	5,546
Actual degree days	4,152	4,652	4,171		
Percent colder (warmer) than average weather[3]	(3)%	9%	(2)%		

(1) Regulatory adjustment for income taxes paid is described below.

(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 2012, average weather represents degree days based on the 25-year average that was set in our 2003 Oregon general rate for the months of January through October, plus the new 25-year average set in the 2012 Oregon general rate case for the months of November and December. For the years 2011 and 2010, average weather represents the 25-year average degree days as set in our 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. Typically, 80% or more of our annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on utility margin and net income is significantly reduced due to our weather normalization mechanism in Oregon. For more information on our weather mechanism, see "Regulatory Matters—Rate Mechanisms—Weather Normalization Tariff" above.

Residential and commercial sales highlights include:

In millions	2012	2011	2010
Volumes - therms:			
Residential sales	395.5	424.9	368.7
Commercial sales	242.4	256.7	227.8
Total volumes	637.9	681.6	596.5
Operating revenues:			
Residential sales	$428.5	$497.2	$463.7
Commercial sales	213.8	247.2	232.7
Total operating revenues	$642.3	$744.4	$696.4
Utility margin:			
Residential:			
Sales	$211.6	$222.5	$197.0
Weather normalization	(0.1)	(10.2)	10.5
Decoupling	8.6	16.7	13.1
Total residential utility margin	220.1	229.0	220.6
Commercial:			
Sales	84.0	87.0	77.8
Weather normalization	0.2	(2.9)	3.5
Decoupling	2.1	2.6	2.4
Total commercial utility margin	86.3	86.7	83.7
Total utility margin	$306.4	$315.7	$304.3

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 return on equity; and a $3.4 million margin increase from our gas reserves investment.

2011 COMPARED TO 2010. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 85.1 million therms, or 14%, primarily reflecting 12% colder weather;
- operating revenues increased $47.9 million, or 7%, primarily due to the 14% volume increase; and
- utility margin increased $11.3 million, or 4%, primarily due to customer growth of 0.8% and colder weather, with colder weather benefits partially offset by weather normalization adjustments.

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.

Industrial sales and transportation highlights include:

In millions	2012	2011	2010
Volumes - therms:			
Industrial - firm sales	34.9	37.6	37.1
Industrial - firm transportation	131.2	133.0	130.1
Industrial - interruptible sales	59.6	59.1	58.4
Industrial - interruptible transportation	248.2	241.0	239.8
Total volumes	473.9	470.7	465.4
Utility margin:			
Industrial - sales and transportation	$28.6	$28.6	$28.5

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

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- 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.

2011 COMPARED TO 2010. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales volumes increased 5.3 million therms, or 1%, primarily reflecting increased energy demand, with the majority of the increased volumes attributable to the manufacturing sector; and
- utility margin increased $0.2 million reflecting an increase in industrial use of natural gas as a result of higher costs for oil and propane fuels, which caused some customers to switch to natural gas. Partially offsetting this trend was the loss of a few large industrial customers due to the economy.

Regulatory Adjustment for Income Taxes Paid

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. For the 2010 tax year, we had originally estimated and accrued $7.1 million. Due to the repeal, the Company recorded a $7.4 million write-off including interest. Results related to SB 408 for 2011 were a pre-tax loss of $7.4 million, compared to a pre-tax gain of $7.7 million in 2010. 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	2012	2011	2010
Other operating revenues	$5.9	$3.7	$4.2

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

- 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.

2011 COMPARED TO 2010. The primary factor contributing to the change in other revenues was as follows:

- other revenues decreased $0.5 million primarily due to a net decrease in revenues from various regulatory adjustments in 2011.

Cost of Gas

Cost of gas as reported by the utility includes gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, production from gas reserves and company gas use. The OPUC and WUTC generally require natural gas commodity costs to be billed to customers at the actual cost incurred, or expected to be incurred, by the utility. Customer rates are set each year so that if cost estimates were met we would not earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have an incentive sharing mechanism whereby we either increase or decrease margin results based on a percentage of actual gas costs as compared to embedded gas costs in the PGA. Under this provision, our net income can be affected by differences between actual and expected gas costs, which occur primarily because of market fluctuations and volatility affecting unhedged gas purchases in the PGA. In addition, we entered into 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-based hedge contracts (derivative instruments), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage our exposure to rising gas prices. Gains and losses from these financial hedge contracts are generally included in our PGA prices and normally do not impact net income because the hedged prices are reflected in our annual rate changes, subject to a regulatory prudence review. However, hedge contracts entered into after the annual PGA rates are set in Oregon 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.

Cost of gas highlights include:

Dollars and therms in millions	2012	2011	2010
Cost of gas	$355.3	$458.5	$424.5
Total volumes sold and delivered (therms)	1,112	1,152	1,062
Average cost of gas (cents per therm)	$0.54	$0.59	$0.61
Total hedge loss	70.2	56.5	61.0
Gain from gas cost incentive sharing	3.8	2.1	1.6

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;

- 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; and
- hedge losses realized and included in cost of gas increased $13.7 million, or 24%. Since the underlying hedge prices were included in our PGA billing rates, these losses did not impact margin or net income.

2011 COMPARED TO 2010. The primary factors contributing to changes in cost of gas were as follows:

- cost of gas increased $34.0 million, or 8%, due to a 9% increase in total sales volumes on 12% colder weather, partially offset by a 4% decrease in the average cost of gas per therm;
- average cost of gas collected through rates decreased 2 cents per therm, primarily reflecting lower gas prices that were passed on to customers through PGA rate decreases effective November 1, 2010 and 2011; and
- hedge losses realized and included in cost of gas decreased $4.5 million, or 7%. As stated above, the underlying hedge prices were included in our PGA billing rates; therefore, these losses did not impact margin or net income.

Actual gas costs in 2012, 2011, and 2010 were below those embedded in rates. The effect on shareholders from the gas cost incentive sharing mechanism was a contribution to margin of $3.8 million in 2012, $2.1 million in 2011, and $1.6 million in 2010. 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 business segment. Pre-tax income from gas storage at Mist and third-party 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 the Gill Ranch gas storage facility. See Note 4.

Gas storage segment highlights include:

In millions, except EPS data	2012	2011	2010
Gas storage net income	$4.5	$4.1	$6.1
EPS - gas storage segment	0.17	0.15	0.23

2012 COMPARED TO 2011. The primary factors contributing to changes in our gas storage segment were as follows:

- 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.

2011 COMPARED TO 2010. The primary factors contributing to changes in our gas storage segment were as follows:

- net income decreased $2.0 million primarily due to a combination of lower storage and asset management revenues driven by lower gas prices and less market volatility.

Business Segments - Other

Our other business segment consists primarily of NNG Financial's investment in the Kelso-Beaver (KB) Pipeline, an equity investment in PGH, which in turn has invested in a cross-Cascade pipeline project, and other miscellaneous non-utility investments and business activities.

Other business highlights include:

In millions, except EPS data	2012	2011	2010
Assets:			
NNG Financial	$1.1	$1.1	$1.1
PGH investment	13.4	13.5	14.8
Net income metrics:			
Other net income (loss)	$0.2	$(0.7)	$0.3
EPS - other segment	—	(0.02)	0.01

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

- total assets at NNG Financial remained flat, primarily reflecting no change in our non-controlling minority interest in the KB interstate gas transmission pipeline;
- our equity investment in PGH remained relatively flat; and
- 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.

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2011 COMPARED TO 2010. The primary factors contributing to changes in our other business segment were as follows:

- total assets at NNG Financial remained flat, primarily reflecting no change in our non-controlling minority interest in the KB interstate gas transmission pipeline;
- our equity investment in PGH reflected an approximately $1.3 million charge taken in 2011; and
- net income decreased $1.0 million primarily due an approximately $1.3 million charge on our investment in PGH. See Note 12.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

In millions	2012	2011	2010
Operations and maintenance	$129.5	$125.4	$121.0

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.

2011 COMPARED TO 2010. Operations and maintenance expense increased $4.3 million or 4% in 2011 compared to 2010. The following summarizes the major factors that contributed to this increase:

- a $3.2 million increase in operating expenses at Gill Ranch related to the first full year of operations;
- a $2.3 million increase in utility payroll expense related to additional field support staff and general pay increases;
- a $1.2 million increase in utility health care costs and other related employee benefit expense;
- a $1.5 million increase in other non-payroll expense at the utility for costs related to the general rate case of $0.7 million, storage leases of $0.3 million, and pipeline integrity and corporate ethics initiatives of $0.2 million; and
- a $0.2 million increase in utility bad debt expense (see further discussion below).

Partially offsetting the above factors were:

- a $1.8 million decrease in performance bonuses at the utility based on below-target results compared to last year;
- a $1.5 million decrease in pension expense due to the regulatory deferral of costs above the amount net in rates (see further discussion below); and
- a $1.0 million decrease in specific consulting and legal fees which were incurred by the utility in 2010 related to our successful property tax appeal.

Our bad debt expense as a percent of revenues was 0.15% for the year ended December 31, 2012, compared to 0.23% in 2011. Our bad debt expense decreased in 2012 partially due to the positive impact of customer refunds on delinquent balances during the period. Our bad debt expense results continue at historically low levels for the

Company despite challenging economic conditions in recent years. We believe credit risks are still somewhat elevated due to the continuing weak economy and high unemployment rates, but we expect our bad debt expense ratio over the long term to remain below 0.5% of revenues.

Our accounting expense for pension costs increased in 2012 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, 2012 and 2011, we deferred pension expenses totaling $7.9 million and $6.0 million, respectively. See Note 8. As a result, increased pension costs had a minimal effect on operations and maintenance expense in 2012 and 2011, 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 are principally comprised of property and payroll taxes and regulatory fees.

General tax highlights include:

In millions	2012	2011	2010
General taxes	$30.6	$29.3	$23.9

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.

2011 COMPARED TO 2010. General taxes increased $5.4 million or 23% in 2011 compared to 2010. The major factors that contributed to the increase are:

- a $5.2 million increase due to a refund of property taxes in 2010, which did not reoccur in 2011. See discussion below; and
- a $1.3 million increase in property taxes at Gill Ranch as a result of the first full year of operations.

In 2010, as a result of successful litigation with the Oregon Department of Revenue (ODOR) regarding property taxes on inventories held for sale, we recognized a net $6.1

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million increase in pre-tax income. This increase consisted of a $5.2 million property tax refund, $1.9 million of accrued interest income, and $1.0 million of increased operations and maintenance expense for legal and consulting services. We received all of the property tax refunds in 2010.

Depreciation and Amortization

Depreciation and amortization highlights include:

In millions	2012	2011	2010
Depreciation and amortization	$73.0	$70.0	$65.1

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

2011 COMPARED TO 2010. Depreciation and amortization expense increased $4.9 million in 2011 over 2010 primarily due to an increase of $3.7 million in Gill Ranch's depreciation, plus additional depreciation on investments in utility plant for customer growth and system improvements.

Other Income and Expense, Net

Other income and expense, net highlights include:

In millions	2012	2011	2010
Gains from company-owned life insurance	$2.3	$2.2	$2.0
Interest income	0.2	0.1	2.0
Income (loss) from equity investments	—	(1.6)	0.6
Net interest on deferred regulatory accounts	4.8	6.0	4.7
Gain (loss) on sale of investments	(0.2)	(0.1)	0.2
Other non-operating	(2.2)	(2.1)	(2.4)
Total other income and expense, net	$4.9	$4.5	$7.1

2012 COMPARED TO 2011. The $0.4 million increase in other income and expense, net for 2012 compared to 2011 was primarily due to a $1.3 million loss from our equity investment in PGH in 2011, which did not reoccur in 2012. This increase was partially offset by $1.2 million of lower interest from net regulatory account balances, which reflected lower average regulatory account balances in 2012 due to environmental insurance recoveries received at the end of 2011 as well as accumulated gas cost savings from November 2011 through June 2012. The Company's refund of gas cost savings increased the regulatory account balances, which resulted in higher interest in the second half of 2012 compared to the first half of 2012. See discussion of Palomar in "Strategic Opportunities—Pipeline Diversification" above and in Note 12.

2011 COMPARED TO 2010. The $2.6 million decrease in other income, net for 2011 compared to 2010 was primarily due to $1.9 million of interest income received from the property tax refund in 2010, which did not occur in 2011, and a $1.4 million loss from equity investments due to Palomar charges, partially offset by a $1.3 million increase in interest

and carrying costs from regulatory account balances largely due to smaller balances in gas costs between 2011 and 2010.

Interest Expense, Net

Interest expense, net highlights include:

In millions	2012	2011	2010
Interest expense, net	$43.2	$42.1	$42.6

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.

2011 COMPARED TO 2010. Interest expense, net of amounts capitalized, in 2011 decreased by $0.5 million compared to 2010. The decrease was primarily due to $1.9 million of savings in interest expense on long-term debt as a result of bonds that were redeemed in 2010, partially offset by a $1.1 million increase for gas storage interest expense related to the Gill Ranch base gas agreement, as well as the issuance of $50 million of 3.176% Company first mortgage bonds (FMBs) in September 2011 and the issuance of $40 million of subsidiary senior secured debt with an average interest rate of 7.38% for Gill Ranch in November 2011.

Interest expense also reflects a lower average interest rate used in calculating the allowance for funds used during construction (AFUDC). AFUDC rates, comprised of short-term and long-term capital costs as appropriate, were 0.3% in 2012, 0.5% in 2011 and 0.6% in 2010.

Income Tax Expense

Income tax expense highlights include:

In millions	2012		2011		2010	
Income tax expense	$44.1		$43.4		$49.5	
Effective tax rate	42.4	%	40.4	%	40.5	%

2012 COMPARED TO 2011. The increase in income tax expense of $0.7 million or 2% and the increase in the effective tax rate was primarily due to a one-time $2.7 million tax charge related to the Oregon general rate case. This increase in taxes was partially offset by lower pre-tax consolidated earnings.

2011 COMPARED TO 2010. The decrease in income tax expense of $6.1 million, or 12% was primarily due to lower pre-tax consolidated earnings.

EFFECTIVE TAX RATES. For the 2012 tax year, the higher effective tax rate was primarily due to the $2.7 million tax charge related to the Oregon general rate case. For the 2011 tax year, the lower effective tax rate was primarily due to a decrease in state tax expense from Measure 67. For the 2010 tax year, the higher effective tax rate was primarily the result of increased amortization of our regulatory tax account on pre-1981 utility plant assets (see "Regulatory Matters—Application of Critical Accounting Policies and

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Estimates," below) and a lower non-taxable gain on company-owned life insurance. For more information on our income taxes, including a reconciliation between the statutory federal and state income tax rates and the effective rate, see Note 2 and Note 9.

For the 2012 tax year, we have stated our deferred tax expense using an estimated blended state tax rate that takes into account different tax rates, tax brackets, and state apportionment that impact our estimated future state income tax liabilities.

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 have access to capital markets at reasonable costs. Our consolidated capital structure was as follows:

	December 31,			
	2012		2011	
Common stock equity	45.4	%	46.5	%
Long-term debt	42.8		41.7	
Short-term debt, including current maturities of long-term debt	11.8		11.8	
Total	100.0	%	100.0	%

Liquidity and Capital Resources

At December 31, 2012, we had $8.9 million of cash and cash equivalents compared to $5.8 million at December 31, 2011. We also had $4.0 million in restricted cash at Gill Ranch as of both December 31, 2012 and 2011, 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, and our use of proceeds from utility specific issuances are restricted to certain utility purposes. Our use of retained earnings is not subject to those same restrictions.

For the utility segment, our short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, borrowings from multi-year credit facilities, cash available from surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We

use utility long-term debt proceeds to finance utility capital expenditures, refinance maturing debt of the utility and provide for general corporate purposes of the utility.

Current market conditions are better than 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 market conditions, we expect that our near term liquidity needs can be met by using cash balances 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, 2012, we had OPUC approval to issue up to $75 million of additional long-term debt under the existing shelf registration for approved purposes.

In the event that our senior unsecured long-term debt credit ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit or other form of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on December 31, 2012, we could have been required to post $1.6 million of collateral to our counterparties, assuming our long-term debt ratings were at non-investment grade levels, which would be a very significant change from current rating levels for NW Natural. See Note 13 and “Credit Ratings” below.

In July 2010, the U.S. Congress passed and President Obama signed into law the “Dodd-Frank Wall Street Reform and Consumer Protection Act” (Dodd-Frank Act or DFA). The legislation established a new statutory framework for the comprehensive regulation of financial institutions that participate in the 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 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, tax benefits and liabilities, environmental expenditures and insurance recoveries, and customer refunds of gas cost savings.

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 MAP-21 Act. See "Application of Critical Accounting Policies—Accounting for Pensions and Postretirement Benefits" below.

With respect to federal income tax liabilities, extensions have been 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 reduces our tax liability for those tax years and is expected to provide cash flow benefits in subsequent years.

With respect to environmental expenditures, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through insurance and utility rates over the next several years, although the amount and timing of these expenditures and recoveries is uncertain. See Note 15, "Results of Operations—Regulatory Matters—Environmental Costs" above.

With respect to customer refunds or credits, gas prices were significantly lower than the gas prices embedded in customer rates between November 1, 2011 and March 31, 2012. As a result, our PGA incentive sharing mechanism deferred 90% of these gas cost savings attributed to Oregon, and 100% of the savings attributed to Washington, into a regulatory account for refund back to customers. See "Results of Operations—Regulatory Matters—Regulatory Mechanisms—Purchased Gas Adjustment" above. Ordinarily, these refunds would be credited to customer rates in the next year's PGA filing, but in the second quarter of 2012 the Company received regulatory approval to immediately credit $35 million to Oregon customers and $4 million to Washington customers through billing credits. In addition, the Company also received approval to provide its Oregon utility customers with a $9 million interstate storage credit from our regulatory incentive sharing mechanism related to gas storage and asset management services. These credits were applied to customer bills in June and July of 2012.

Our gas storage segment's short-term liquidity is supported by cash balances, internal cash flow from operations, external financing, and, to a certain extent, funding from its parent company. Gill Ranch has limited operational history, having begun operations in October 2010. Although we anticipate operating cash flows to be sufficient for liquidity purposes, the amount and timing of these cash flows are uncertain. 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, 2012. 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 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 agreements, Gill Ranch is also subject to a debt service reserve requirement of 10% of the outstanding principal amount, initially $4 million, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on the incurrence of additional debt. As of and for the year ended December 31, 2012, we were in compliance with all covenants and restrictions under the debt agreements.

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

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 amount and timing of dividends payable on our common stock is at the sole discretion of our Board of Directors. Subject to Board approval, we expect to continue paying quarterly cash dividends on common stock. However, the declarations and amount of future dividends will depend upon our earnings, cash flows, financial condition and other factors including Board approval.

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, 2012 by maturity and type of obligation:

	Payments Due in Years Ending December 31,						
In millions	2013	2014	2015	2016	2017	Thereafter	Total
Commercial paper	$190.3	$—	$—	$—	$—	$—	$190.3
Long-term debt maturities	—	60.0	40.0	65.0	40.0	486.7	691.7
Interest on long-term debt	40.1	40.0	38.5	35.5	30.3	249.7	434.1
Postretirement benefit payments(1)	21.7	22.3	22.9	23.7	24.5	140.1	255.2
Capital leases	0.6	0.3	0.2	—	—	—	1.1
Operating leases	5.4	5.7	5.5	5.5	5.5	33.1	60.7
Gas purchases(2)	104.4	12.2	—	—	—	—	116.6
Gas pipeline capacity commitments	94.3	86.1	72.7	61.4	48.5	240.9	603.9
Gas reserves(3)	56.6	49.2	41.8	—	—	—	147.6
Other purchase commitments(4)	—	0.5	0.1	—	—	13.6	14.2
Other long-term liabilities(5)	15.3	—	—	—	—	—	15.3
Total	$528.7	$276.3	$221.7	$191.1	$148.8	$1,164.1	$2,530.7

(1) The majority of these estimated postretirement benefit payments are related to our qualified defined benefit pension plans, which are funded by plan assets and future cash contributions. 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, 2012. 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. 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 twelve 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, 2012, 623 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 new five-year labor agreement called the Joint Accord. The 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 current Joint Accord 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.

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, 2012 and 2011, our utility had commercial paper outstanding of $190.3 million and $141.6 million, respectively. The effective interest rate on the utility's commercial paper outstanding at December 31, 2012 and 2011 was 0.3%.

Credit Agreements

In December 2012, we entered into a new multi-year credit agreement for unsecured revolving loans totaling $300 million with a maturity date of December 20, 2017 and an available extension of commitments for two additional one-year periods, subject to lender approval. Our prior $250 million agreement, dated May 31, 2007, was terminated upon the closing of this new agreement. All lenders under the new agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2012 as follows:

In millions

Lender rating, by category	Loan Commitment
AA/Aa	$123
A/A	177
BBB/Baa	—
Total	$300

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

Our credit agreement allows us to request increases in the total commitment amount, up to a maximum of $450 million. The agreement also permits the issuance of letters of credit in an aggregate amount of up to $200 million. Any principal and unpaid interest amounts owed on borrowings under the credit agreements is due and payable on or before the maturity date. There were no outstanding balances under this or our prior credit agreement at December 31, 2012 or 2011. Both the current and former 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, 2012 and 2011, with consolidated indebtedness to total capitalization ratios of 54.6% and 53.5%, respectively.

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

Credit Ratings
Our debt credit ratings are a factor in our liquidity, affecting our access to the capital markets including the commercial paper market. Our debt credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. In December 2012, Moody's downgraded our short-term debt rating from P-1 to P-2. In February 2013, S&P upgraded our secured long-term first mortgage bond rating from A+ to AA-. These changes have not materially impacted our liquidity, access to the short-term commercial paper markets, or our borrowing costs. There were no other changes in our credit ratings during 2012.

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	Negative

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	2012	2011	2010

Company First Mortgage Bonds			
4.11% Series B due 2010	$—	$—	$10
7.45% Series B due 2010	—	—	25
6.665% Series B due 2011	—	10	—
7.13% Series B due 2012	40	—	—
	$40	$10	$35

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	2012	2011	2010
Cash provided by operating activities	$168.8	$233.5	$126.5

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

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colder weather at the end of 2011, which were collected early in 2012.

Also affecting cash flow from operating activities is the amount of cash contributions made to the utility's qualified defined benefit pension plans. During the year ended December 31, 2012, we contributed $23.5 million to these plans, which was significantly higher than the $5.4 million in non-cash expense recognized on the income statement. In 2011, we contributed $22.0 million and had $7.2 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 funding relief approved under the new MAP-21 Act in July 2012. 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 (the Tax Relief Act). The Tax Relief Act allowed 100% bonus depreciation on 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 during 2012. These and other tax benefits resulted in a net operating tax loss for 2010, which was carried back to the tax year 2009 and resulted in a federal income tax refund of $22.3 million received in 2011 and an additional $2.1 million received in 2012. We generated taxable income in 2011 that was fully offset by net operating loss (NOL) carried forward from 2010. We continued to generate NOL carryforwards during 2012. As of December 31, 2012, we had an estimated federal income tax receivable balance of $2.3 million and an estimated NOL carryforward balance of $83.4 million to 2013. In 2011, Oregon conformed with federal bonus depreciation, contributing to a state NOL carryforward of $76.6 million to 2013. We anticipate being able to use the full amount of the 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.

2011 COMPARED TO 2010. The significant factors contributing to the $107.0 million increase in operating cash flow for 2011 compared to 2010 are as follows:

- an increase of $85.7 million from accrued taxes, primarily related to bonus depreciation which resulted in federal tax refunds of $36.6 in 2011 and a NOL carryforward;
- an increase of $34.7 million from changes in deferred gas costs, which reflects a higher level of gas cost savings which will be refunded to utility customers in subsequent years' PGA;
- an increase of $33.4 million from insurance recoveries for environmental claims, net of deferred environmental expenditures in 2011; and
- an increase of $12.0 million from changes in accounts payable due to decreased construction activity at Gill Ranch.

Partially offsetting these increases was:

- a decrease of $29.5 million from changes in deferred tax liabilities primarily reflecting higher tax benefits in 2010 compared to 2011, largely driven by utility and Gill Ranch

bonus depreciation for investments placed in service during 2010;

- a decrease of $22.1 million from changes in receivables primarily due to higher balances at the end of 2009, which benefited cash flows in 2010; and
- a decrease of $12.0 million from higher pension contributions due to a decline in interest rates and asset values, which increased pension funding requirements.

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

Investing Activities

Investing activity highlights include:

In millions	2012	2011	2010
Total cash used in investing activities	$184.7	$153.1	$212.9
Capital expenditures	132.0	100.5	248.5
Utility gas reserves	54.1	50.6	—

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.

2011 COMPARED TO 2010. The $59.8 million decrease in cash used in investing activities was due to lower capital expenditures primarily due to decrease in non-utility construction activity in 2011 as our Gill Ranch facility was primarily constructed in 2010. Offsetting this decrease was our investment in utility gas reserves.

Over the five-year period 2013 through 2017, 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 $150 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 2013, we expect to spend between $10 and $15 million on non-utility capital projects. Non-utility spend for gas storage and other investments after 2013 will depend largely on future decisions about potential expansion opportunities in gas storage and pipeline projects. Gas storage segment capital expenditures in 2013 are expected to be paid primarily from working capital, and potentially with additional funds from NW Natural.

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Financing Activities

Financing activity highlights include:

In millions	2012	2011	2010
Total cash provided by (used in) financing activities	$18.9	$(78.0)	$81.4
Change in short-term debt	48.7	(115.8)	155.4
Change in long-term debt	10.0	80.0	(35.0)
Cash dividend payments	(48.0)	(46.7)	(44.7)

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 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.

2011 COMPARED TO 2010. The $159.4 million increase to cash used in financing activities is primarily due to our short-term debt balances, which decreased $115.8 million. We retired $10 million of long-term debt and issued $50 million of utility long-term debt and $40 million of subsidiary long-term debt by Gill Ranch.

We have a stock repurchase program approved through May 2013 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 2012, 2011 or 2010 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 the 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 $19.1 million in 2012, an increase of $2.8 million from 2011.

The fair market value of pension assets in this plan increased to $249.6 million at December 31, 2012 from $216.0 million at December 31, 2011. The increase was due to a return on plan assets of $26.7 million plus $23.5 million in employer contributions, partially offset by benefit payments of $16.5 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 $154.4 million at December 31, 2012. We plan to make contributions during 2013 of up to $15 million.

We also contribute 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 $0.4 million to the Union Plan in both 2012 and 2011. See Note 8 for further pension disclosures.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2012, 2011, and 2010, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission (SEC) method, were 3.30, 3.41, and 3.73, 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. See Exhibit 12.

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, 2012, we had a regulatory asset of $126.5 million for deferred environmental costs, which includes $69.7 million for additional costs expected to be paid in the future and $23.4 million of accrued interest. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 15 and "Results of Operations—Regulatory Matters—Rate Mechanisms—Environmental Costs" above.

New Accounting Pronouncements

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

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APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

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) require 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 expenses from, or are required to refund them 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 all of our regulatory assets and liabilities at December 31, 2012 and 2011 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, 2012 and 2011 was $131.4 million and $156.6 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. Estimated unbilled revenue at December 31, 2012 and 2011 was $57.0 million and $61.9 million, respectively. The decrease in accrued unbilled revenue at year-end 2012 was primarily due to lower volumes in December 2012, reflecting warmer weather late in the month, and lower 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, 2012 was adjusted up or down by 1%:

In millions	2012 Up 1%	Down 1%
Unbilled revenue increase (decrease)	$2.0	$(1.9)
Utility margin decrease	(0.4)	0.4
Net income decrease	(0.2)	0.2

SENATE BILL 408 AND 967. From 2007 through 2010, utility revenues included the recognition of a regulatory adjustment for income taxes paid (commonly referred to as SB 408). Under 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.

Accounting for 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, 2012 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.

Derivative contracts not qualifying for regulatory deferral are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2012, all of our derivatives were effective economic hedges and either qualified or were expected to qualify for regulatory deferral or hedge accounting treatment. We use the hypothetical derivative method under accounting standards for derivatives and hedging to determine the hedge effectiveness for our interest rate swaps and the dollar offset method for other derivative contracts under accounting standards for derivatives and hedging. The effectiveness test applied to financial derivatives is dependent on the type of derivative and its use.

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

In millions	2012	2011	2010
Net utility gain (loss) on:			
Commodity-price swaps	$(69.5)	$(53.8)	$(60.4)
Commodity-price options	(0.7)	(2.7)	(0.6)
Subtotal	(70.2)	(56.5)	(61.0)
Foreign currency forward purchases	—	(0.1)	0.1
Total net loss realized	$(70.2)	$(56.6)	$(60.9)

Realized gains (losses) from commodity hedges and foreign currency forward purchase contracts shown above were recorded as reductions (increases) to cost of gas and were included in our annual PGA rates.

Accounting for Pensions and Postretirement Benefits

We maintain a qualified non-contributory defined benefit pension plan covering a majority of our utility employees, several non-qualified supplemental pension plans for eligible executive officers and certain key employees, and other postretirement employee benefit plans covering

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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 were not available to employees at any of our subsidiary companies. We currently offer our utility and subsidiary employees an enhanced Retirement K Savings Plan benefit. The postretirement Welfare Benefit Plan for non-union employees was also closed to new participants several years ago.

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

Accounting standards also require balance sheet recognition of the overfunded or underfunded status of pension and postretirement benefit plans in AOCI, net of tax, based on the fair value of plan assets compared to the actuarial value of future benefit obligations. However, the retirement benefit costs related to our qualified defined benefit pension and postretirement benefit plans are generally recovered in utility rates, which are set based on accounting standards for pensions and postretirement benefit expenses. We also received approval from the OPUC pursuant to regulatory accounting 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 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. In 2012, the cumulative amount deferred for future pension cost recovery was $15.0 million. The regulatory balancing account earns a carrying cost at the authorized cost of capital rate set by the OPUC.

A number of factors are considered in developing pension and postretirement benefit assumptions, including evaluations of relevant discount rates, an evaluation of expected long-term investment returns, expected changes in salaries and wages, analyses of past retirement plan experience and current market conditions and input from actuaries and other consultants. For the December 31, 2012 measurement date, we reviewed and updated:

- our weighted-average discount rate assumptions for pensions and other postretirement benefits, which went from 4.51% to 3.85% and from 4.33% to 3.56%, respectively. The new rate assumptions were determined for each plan based on a matching of benchmark interest rates to the estimated cash flows, which reflects 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 was reduced from 8.00% to 7.50%; and
- other key assumptions, which were based on actual plan experience and actuarial recommendations.

At December 31, 2012, our net pension liability (benefit obligations less market value of plan assets) for the qualified defined benefit plan increased $7.4 million compared to 2011. The increase in our net pension liability is primarily due to the $41.1 million increase in our pension benefit obligation, offset by an increase of $33.6 million in plan assets. The liability for non-qualified plans increased $3.7 million, and the liability for other postretirement benefits increased $3.1 million in 2012.

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 evaluate an analysis of 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, 2012, the actual annualized returns on plan assets, net of management fees, for the past one-year, five-years, 10-years and since inception were 12.4%, 0.9%, 7.1% and 10.0%, respectively.

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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 2012 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2012
Discount rate:	(0.25)%		
Qualified defined benefit plans		$1.2	$13.6
Non-qualified plans		—	0.9
Other postretirement benefits		0.1	0.9
Expected long-term return on plan assets:	(0.25)		
Qualified defined benefit plans		0.6	N/A

In July 2012, President Obama signed into law the Moving Ahead for Progress in the 21st Century Act (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. For 2013, the new corridor will be set at no less than 85% and no more than 115% of the corresponding 25-year average segment rate. In 2014, the corridor widens to 80% to 120% of the 25-year average, and the corridor continues to widen by 5% each year thereafter until reaching 70% to 130%. Under current market conditions, we estimate the segment rate for the 2013 Plan Year will increase from approximately 4.90% to 6.25%, and this 1.35% increase in interest rates would reduce our minimum contribution requirement by approximately $15 million, from roughly $26 million under the unadjusted 24-month segment rate to roughly $11 million under the adjusted 24-month segment rate using the 85% to 115% corridor.

Accounting for 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, 2012 and 2011, our net long-term deferred tax liability totaled $446.6 million and $413.2 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, 2012, 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 have 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, 2012 and 2011, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $60.3 million and $68.5 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, 2012, 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.

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

Accounting for 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 depend 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 range of potential liabilities could be significantly different than 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 $69.7 million as of December 31, 2012. 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. Pursuant to the 2012 Oregon general rate case, environmental cost deferrals will be recovered under the new SRRM subject to a reduction for separate insurance recoveries, a prudence review, and an earnings test that will be defined in a separate regulatory proceeding, which is currently open. 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 both the insurance recovery 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 and Note 15.

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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 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 commodity-price financial swap and option contracts (financial hedge contracts) to convert certain natural gas supply contracts from floating prices to fixed or capped prices. We also hedge 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. At December 31, 2012 and 2011, notional amounts under foreign currency forward contracts totaled $13.2 million and $12.3 million, respectively. As of December 31, 2012, all foreign currency forward contracts mature within one year. If all of the foreign currency forward contracts had been settled on December 31, 2012, a gain of $0.1 million would have been realized. See Note 13.

Credit Risk

CREDIT EXPOSURE TO NATURAL GAS SUPPLIERS. Certain gas suppliers have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers at liquid exchange points. We evaluate and monitor suppliers' creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit, or surety bonds, in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We expect these costs would be subject to our PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the monthly market index price tied to liquid exchange points, and we have significant 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, 2012, our overall credit exposure relating to commodity hedge 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, 2012, we do not have any actual derivative credit risk exposure, which reflects amounts that financial derivative counterparties owe to us.

The following table summarizes our overall 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 Loss			
In millions	2012		2011	
AAA/Aaa	$—		$—	
AA/Aa	(5.0	)	(57.6	)
A/A	—		(5.9	)
BBB/Baa	—		—	
Total	$(5.0	)	$(63.5	)

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

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day with a single counterparty are netted and a single payment is delivered or received depending on which party is due funds.

Additionally we have master contracts in place with each of our derivative counterparties that include provisions for posting or calling for collateral. Generally we can obtain cash or marketable securities as collateral with one day’s notice. We use various collateral management strategies to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in the significant posting of collateral, if any. We have performed stress tests on the portfolio and concluded 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, which reflects amounts we believe are owed to us, could be material. 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, 2012, approximately 9% of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 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.

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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, 2012. 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.

Based on our assessment and those criteria, management has concluded that we maintained effective internal control over financial reporting as of December 31, 2012.

The effectiveness of internal control over financial reporting as of December 31, 2012 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

March 1, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying table of contents present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, based on criteria established in Internal Control - Integrated Framework 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
March 1, 2013

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

In thousands, except per share data	Year Ended December 31, 2012	2011	2010
Operating revenues	$730,607	$828,055	$792,115
Operating expenses:			
Cost of gas	355,335	458,508	424,494
Operations and maintenance	129,477	125,417	121,020
General taxes	30,598	29,281	23,872
Depreciation and amortization	73,017	70,004	65,124
Total operating expenses	588,427	683,210	634,510
Income from operations	142,180	144,845	157,605
Other income and expense, net	4,936	4,523	7,102
Interest expense, net	43,157	42,088	42,578
Income before income taxes	103,959	107,280	122,129
Income tax expense	44,104	43,382	49,462
Net income	59,855	63,898	72,667
Other comprehensive income:			
Change in employee benefit plan liability, net of taxes of $1,339 for 2012, $1,161 for 2011, and $674 for 2010	(2,156)	(1,779)	(1,027)
Amortization of non-qualified employee benefit plan liability, net of taxes of ($434) for 2012, ($383) for 2011, and ($257) for 2010	665	583	391
Comprehensive income	$58,364	$62,702	$72,031
Average common shares outstanding:			
Basic	26,831	26,687	26,589
Diluted	26,907	26,744	26,657
Earnings per share of common stock:			
Basic	$2.23	$2.39	$2.73
Diluted	2.22	2.39	2.73
Dividends declared per share of common stock	1.79	1.75	1.68

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2012	2011
Assets:		
Current assets:		
Cash and cash equivalents	$8,923	$5,833
Accounts receivable	61,229	77,449
Accrued unbilled revenue	56,955	61,925
Allowance for uncollectible accounts	(2,518)	(2,895)
Regulatory assets	52,448	94,673
Derivative instruments	1,950	2,853
Inventories	67,602	74,363
Gas reserves	14,966	4,463
Income taxes receivable	2,552	7,045
Other current assets	19,592	22,980
Total current assets	283,699	348,689
Non-current assets:		
Property, plant, and equipment	2,786,008	2,661,102
Less: Accumulated depreciation	812,396	767,226
Total property, plant, and equipment, net	1,973,612	1,893,876
Gas reserves	84,693	47,451
Regulatory assets	387,888	371,392
Derivative instruments	3,639	—
Other investments	67,667	68,263
Restricted cash	4,000	4,000
Other non-current assets	13,555	12,903
Total non-current assets	2,535,054	2,397,885
Total assets	$2,818,753	$2,746,574

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
In thousands	2012	2011
Liabilities and equity:		
Current liabilities:		
Short-term debt	$190,250	$141,600
Current maturities of long-term debt	—	40,000
Accounts payable	85,613	86,300
Taxes accrued	9,588	10,747
Interest accrued	5,953	5,857
Regulatory liabilities	20,792	31,046
Derivative instruments	10,796	57,317
Other current liabilities	45,444	41,597
Total current liabilities	368,436	414,464
Long-term debt	691,700	641,700
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	446,604	413,209
Regulatory liabilities	288,113	278,382
Pension and other postretirement benefit liabilities	215,792	201,530
Derivative instruments	578	6,536
Other non-current liabilities	74,497	76,265
Total deferred credits and other non-current liabilities	1,025,584	975,922
Commitments and contingencies (see Note 14 and Note 15)	—	—
Equity:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,917 and 26,756 at December 31, 2012 and 2011, respectively	356,571	348,383
Retained earnings	385,753	373,905
Accumulated other comprehensive loss	(9,291)	(7,800)
Total equity	733,033	714,488
Total liabilities and equity	$2,818,753	$2,746,574

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, 2009	$337,361	$328,712	$(5,968)	$660,105
Comprehensive income	—	72,667	(636)	72,031
Dividends paid on common stock	—	(44,652)	—	(44,652)
Tax expense from employee stock option plan	(125)	—	—	(125)
Stock-based compensation	554	—	—	554
Issuance of common stock	5,188	—	—	5,188
Balance at Dec. 31, 2010	342,978	356,727	(6,604)	693,101
Comprehensive income	—	63,898	(1,196)	62,702
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	373,905	(7,800)	714,488
Comprehensive income	—	59,855	(1,491)	58,364
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	$385,753	$(9,291)	$733,033

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
In thousands	2012	2011	2010
Operating activities:			
Net income	$59,855	$63,898	$72,667
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	73,017	70,004	65,124
Deferred tax liabilities	42,780	46,877	76,410
Non-cash expenses related to qualified defined benefit pension plans	5,448	7,191	8,009
Contributions to qualified defined benefit pension plans	(23,500)	(22,045)	(10,000)
Deferred environmental expenditures, net of recoveries	(12,503)	25,586	(7,826)
Other	3,990	280	(2,853)
Changes in assets and liabilities:			
Receivables	22,170	(6,246)	15,830
Inventories	6,761	6,022	572
Taxes accrued	3,334	34,189	(51,524)
Accounts payable	(602)	148	(11,846)
Interest accrued	96	675	(253)
Deferred gas costs	(17,644)	8,565	(26,090)
Other, net	5,636	(1,682)	(1,751)
Cash provided by operating activities	168,838	233,462	126,469
Investing activities:			
Capital expenditures	(132,029)	(100,534)	(248,505)
Utility gas reserves	(54,085)	(50,597)	—
Restricted cash	—	(3,076)	34,619
Other	1,437	1,142	1,015
Cash used in investing activities	(184,677)	(153,065)	(212,871)
Financing activities:			
Common stock issued, net	6,758	3,040	4,598
Long-term debt issued	50,000	90,000	—
Long-term debt retired	(40,000)	(10,000)	(35,000)
Change in short-term debt	48,650	(115,835)	155,435
Cash dividend payments on common stock	(48,007)	(46,690)	(44,652)
Other	1,528	1,464	1,046
Cash provided by (used in) financing activities	18,929	(78,021)	81,427
Increase (decrease) in cash and cash equivalents	3,090	2,376	(4,975)
Cash and cash equivalents, beginning of period	5,833	3,457	8,432
Cash and cash equivalents, end of period	$8,923	$5,833	$3,457
Supplemental disclosure of cash flow information:			
Interest paid	$43,061	$41,413	$41,037
Income taxes paid	2,979	1,756	22,600

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidation of Northwest Natural Gas Company (NW Natural or the Company) and all companies that we directly or indirectly control, either through majority ownership or otherwise. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), and NNG Financial Corporation (NNG Financial). Investments in corporate joint ventures and partnerships that we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method or the cost method, which includes NWN Energy’s investment in Palomar Gas Holdings, LLC (PGH) and NNG Financial's investment in 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 business and other non-utility investments and business activities.

Certain prior year balances in our consolidated financial statements and notes have been reclassified to conform with the current presentation. Specifically, the consolidated statement of comprehensive income has been reorganized, and cost of gas is now included in the section for total operating expenses. Net operating revenues, which was primarily used to show profit margins from the sale of gas, is no longer presented as a subtotal in the statement of comprehensive income. These changes, including the one noted above, 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 Public Utility Commission of Oregon (OPUC) and Washington Utilities and Transportation Commission (WUTC), and natural gas storage services, which are regulated by either the Federal Energy Regulatory Commission (FERC) or the California Public Utilities Commission (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, 2012 and 2011 the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets	
In thousands	2012	2011
Current:		
Unrealized loss on derivatives(1)	$10,796	$57,317
Pension and other postretirement benefit liabilities(2)	17,247	15,491
Other(3)	24,405	21,865
Total current	$52,448	$94,673
Non-current:		
Unrealized loss on derivatives(1)	$578	$6,536
Pension balancing(2)	15,022	6,008
Income tax asset	55,879	65,264
Pension and other postretirement benefit liabilities(2)	182,688	170,512
Environmental costs(4)	126,482	105,670
Other(3)	7,239	17,402
Total non-current	$387,888	$371,392

	Regulatory Liabilities	
In thousands	2012	2011
Current:		
Gas costs	$9,100	$17,994
Unrealized gain on derivatives(1)	1,950	2,853
Other(3)	9,742	10,199
Total current	$20,792	$31,046
Non-current:		
Gas costs	$—	$8,420
Unrealized gain on derivatives(1)	3,639	—
Accrued asset removal costs	281,213	267,355
Other(3)	3,261	2,607
Total non-current	$288,113	$278,382

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

(2) Certain pension costs of the utility 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 or earn a rate of return or carrying charge. See Note 8.

(3) 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.

(4) Environmental costs relate to specific sites approved for regulatory deferral. In Oregon we earn a rate of return on amounts paid, whereas amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended. Environmental costs related to Washington were deferred beginning in 2011, with cost recovery and a carrying charge to be determined in a future proceeding. In the 2012 rate case, the OPUC authorized a Site Remediation and Recovery Mechanism (SRRM) that allows the Company to recover

prudently incurred environmental costs, subject to an earnings test that will be defined in a future rate proceeding.

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 realized. 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 cost incurred and deferred at December 31, 2012 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 against earnings in the period such determination is made.

New Accounting Standards

Adopted Standards

FAIR VALUE MEASUREMENT. In May 2011, the Financial Accounting Standards Board (FASB) issued amendments to the authoritative guidance on fair value measurement. The amendments are primarily related to disclosure requirements for Level 3 fair value assets and were effective for periods beginning after December 15, 2011. The adoption of this standard did not have a material effect on our financial statement disclosures.

Recent Accounting Pronouncements

BALANCE SHEET OFFSETTING. In December 2011, the 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 is effective for annual reporting periods beginning after January 1, 2013, and we do not expect this standard to have a material effect on our financial statement disclosures.

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. See Note 10.

In accordance with long-standing regulatory treatment, our depreciation rates are comprised 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.

Our provision for depreciation of utility plant and property is computed under the straight-line method in accordance with depreciation studies approved by regulatory authorities. The weighted average depreciation rate for utility assets in service was approximately 2.8% in 2012, 2011, and 2010, reflecting the approximate weighted average economic life of the property. This includes 2012 weighted average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.2% for gas storage facilities, 4.7% for general plant, and 4.8% for intangible and other fixed assets.

Allowance for Funds Used During Construction
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 return on equity (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 2012, 0.5% in 2011, and 0.6% in 2010.

Cash and Cash Equivalents
For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with maturity dates of three months or less. At December 31, 2012 and 2011, outstanding checks of approximately $2.3 million and $3.9 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, 2012 and 2011 was $57.0 million and $61.9 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. Under SB 408, we 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 the difference between income taxes paid and income taxes authorized to be collected in customer rates. We recorded the refund, or surcharge, each quarter based on estimates of the annual amount to be recognized. In 2011, SB 408 was repealed and replaced by Senate Bill 967. SB 967 required utilities to eliminate amounts accrued under SB 408 for the 2010 and 2011 tax years, thereby denying recovery by NW Natural of the surcharge accrued for 2010, which resulted in a one-time pre-tax charge of $7.4 million in the second quarter of 2011. Pursuant to SB 967, we changed our revenue recognition policy effective January 1, 2011 and no longer recognize a regulatory adjustment for income taxes for SB 408.

Non-utility revenues are derived primarily from the gas storage business segment. At Mist, revenues are recognized upon delivery of services to customers. Revenues from our asset management partner are recognized over the life of the asset management contract for guaranteed amounts, if any, and are recognized as earned for amounts above the guaranteed amount. At Gill Ranch, 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. Asset management revenue is recognized using a straight-line, pro rata methodology over the term of each contract and provides us with the majority of the pre-tax income from our independent energy marketing company. See Note 4.

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 added to the general allowance 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 credit worthiness and the level of natural gas prices. Each quarter the allowance for uncollectible accounts is adjusted, as necessary, based on information currently available.

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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, exclude cushion gas and consist 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 recorded at original cost and classified as long-term assets.

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

Our utility and gas storage inventories totaled $58.8 million and $65.6 million at December 31, 2012 and 2011, respectively, and our materials and supplies inventories totaled $8.8 million at December 31, 2012 and 2011.

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 and calculate using the estimated gas reserves and the 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. Derivative contracts entered into for utility customer requirements after the annual PGA rate has been set are subject to the PGA incentive sharing mechanism. Effective November 1, 2008, Oregon approved a PGA sharing mechanism under which we are required to select either an 80% deferral 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, 2012, 2011 and 2010, we selected a 90% deferral of gas cost differences. In Washington, 100% of our gas cost differences 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 and to prevent 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 necessary to support normal business activities. We do not enter into derivative instruments for trading purposes and we believe that any increase in market risk created by holding derivatives should be offset by the exposures they modify.

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.

Revenue Taxes
Revenue-based taxes are primarily franchise taxes, which are collected from customers and remitted to taxing authorities. Revenue taxes are recorded gross and are included in operating revenues in the statement of comprehensive income.

Income Tax Expense
NW Natural and its wholly-owned subsidiaries file consolidated federal, state, and local income tax returns. Current income taxes are allocated based on each entity’s

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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 $60.3 million and $68.5 million at December 31, 2012 and 2011, 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 book 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.

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

3. EARNINGS PER SHARE

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

In thousands, except per share data	2012	2011	2010
Net income	$59,855	$63,898	$72,667
Average common shares outstanding - basic	26,831	26,687	26,589
Additional shares for stock-based compensation plans (See Note 6)	76	57	68
Average common shares outstanding - diluted	26,907	26,744	26,657
Earnings per share of common stock - basic	$2.23	$2.39	$2.73
Earnings per share of common stock - diluted	$2.22	$2.39	$2.73
Additional information:			
Antidilutive shares not included in net income per diluted common share calculation	1	2	1

4. SEGMENT INFORMATION

We operate in two primary reportable business segments, local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as “other.” We refer to our local gas distribution business as the “utility,” and our “gas storage” and “other” business segments as “non-utility.” Our 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 our Mist underground storage facility in Oregon (Mist) and third-party asset management services. Our “other” segment includes NNG Financial and our equity investment in PGH, which is pursuing development of the Palomar 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 50% to 60% of our utility’s total volumes delivered and 80%

to 90% of our utility's margin. Industrial customers account for the remaining 40% to 50% of volumes and 5% to 15% of utility margin. The remaining 10% or less of utility margin is derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism and other service fees.

Industrial customers 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 a significant portion of our utility revenues or utility margins.

Gas Storage

Our gas storage business segment includes natural gas storage services provided to customers primarily from two underground natural gas storage facilities, our Gill Ranch gas storage facility, which commenced commercial operation in October 2010, 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, 2012, 2011 and 2010, this business segment derived a majority of its revenues from asset management services and from firm and interruptible gas storage contracts.

Mist Gas Storage Facility

Earnings from non-utility assets at the Mist facility are primarily related to firm storage capacity revenues. Earnings for the gas storage segment 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.

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.

Other

We have non-utility investments and other business activities which are aggregated and reported as a business segment called "other." Although in aggregate these investments and activities are currently not material to consolidated operations, we identify and report them as a stand-alone segment based on our organizational structure and decision-making process because these business investments and activities are not specifically related to our utility or gas storage segments. This segment 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. This segment 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 $1.1 million at both December 31, 2012 and 2011.

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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
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	55,125	4,521	209	59,855
Capital expenditures	130,151	1,541	337	132,029
Total assets at December 31, 2012	2,511,288	291,568	15,897	2,818,753
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	60,527	4,101	(730)	63,898
Capital expenditures	94,049	6,485	—	100,534
Total assets at December 31, 2011	2,435,888	294,637	16,049	2,746,574
2010				
Operating revenues	$770,642	$21,250	$223	$792,115
Depreciation and amortization	62,661	2,463	—	65,124
Income from operations	145,688	11,855	62	157,605
Net income	66,262	6,110	295	72,667
Capital expenditures	85,929	161,634	942	248,505

The following table presents additional summary information concerning utility margin. The gas storage and other segments emphasize operating revenues and net income growth as opposed to margin growth because these segments do not incur cost of sales expenses like the utility and, therefore, use revenues and net income to assess performance.

In thousands	2012	2011	2010
Utility margin calculation:			
Utility operating revenues	$699,862	$801,478	$770,642
Less: Utility cost of gas	355,335	458,508	424,494
Utility margin	$344,527	$342,970	$346,148

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5. COMMON STOCK

Common Stock

As of December 31, 2012 and 2011, our common shares authorized were 100,000,000. As of December 31, 2012, we had reserved for issuances 137,798 shares of common stock under the Employee Stock Purchase Plan (ESPP) and 197,112 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 529,925 options outstanding at December 31, 2012, 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 2013 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, 2012. 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 for the years 2012, 2011, and 2010:

In thousands	Shares
Balance, December 31, 2009	26,533
Sales to employees under ESPP	24
Exercise of stock options under Restated SOP, net	111
Balance, December 31, 2010	26,668
Sales to employees under ESPP	15
Exercise of stock options under Restated SOP, net	24
Sales to shareholders under DRPP	49
Balance, December 31, 2011	26,756
Sales to employees under ESPP	18
Exercise of stock options under Restated SOP, net	47
Sales to shareholders under DRPP	96
Balance, December 31, 2012	26,917

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6. STOCK-BASED COMPENSATION

Our stock-based 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 the second quarter of 2012. Together these plans are designed to promote stock ownership in NW Natural by employees and officers.

Long-Term Incentive Plan
The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. Under the amended 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 600,000 shares were authorized for issuance as of December 31, 2011. An additional 250,000 shares were authorized for issuance as stock options in 2012. Shares awarded under the LTIP may be purchased on the open market or issued as new shares.
Of the 850,000 shares authorized for any LTIP award at December 31, 2012, 311,571 shares of common stock were available for any type of award under the LTIP, assuming that market, performance, and service based grants currently outstanding are awarded at the target level. Additionally, the 250,000 shares of common stock added in 2012 were available for option grants at December 31, 2012. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2012 or 2011. 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 for 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 based on three-year performance periods. At December 31, 2012, certain performance share measures had been achieved for the 2010-12 award period. Accordingly, participants are estimated to receive 9,022 shares of common stock and 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. At December 31, 2011 and 2010, we awarded 8,428 and 8,007 shares of common stock, respectively, for the 2009-11 and 2008-10 award periods, plus 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. In 2011 and 2010, we expensed $0.4 million and $0.2 million, respectively, for both the 2009-11 and 2008-10 performance share award periods, and on a cumulative basis we accrued a total of $0.8 million and $0.7 million, respectively, related to the 2009-11 and 2008-10 performance periods.

At December 31, 2012, the aggregate number of performance shares granted and outstanding at the target and maximum levels were as follows:

	Performance Shares Awards Outstanding		2012	Cumulative Expense
Performance Period	Target	Maximum	Expense	At Dec. 31, 2012
2010-12	$41,500	$83,000	$452	$1,170
2011-13	37,950	75,900	294	570
2012-14	35,340	70,680	635	635
Total	$114,790	$229,580	$1,381	

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 compensation based on performance levels achieved and an estimated fair value using a Black-Scholes or binomial model. The weighted-average grant

date fair value of unvested shares at December 31, 2012 and 2011 was $51.42 and $25.06 per share, respectively. The weighted-average grant date fair value of shares vested during the year was $45.05 per share and for shares granted during the year was $22.35 per share.

Restricted Stock Units
In 2012, the Company began granting RSUs under the LTIP instead of stock options under the Restated SOP. RSUs

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include a performance based threshold and a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of the RSU. During the year ended December 31, 2012, the Company granted 25,224 RSUs under the LTIP with grant date fair values ranging from $44.43 to $48.25 per share.

Restated Stock Option Plan

The Restated SOP was terminated for new option grants in 2012; however, options that had been granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture or exercise. Any new grants of stock options would be made under the LTIP. No new stock options were granted during 2012.

At December 31, 2012, a total of 529,925 shares of common stock remained reserved for issuance under the Restated SOP with none 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		2010	
Risk-free interest rate	2.0	%	2.3	%
Expected life (in years)	4.5		4.7	
Expected market price volatility factor	24.5	%	23.2	%
Expected dividend yield	3.8	%	3.8	%
Forfeiture rate	3.1	%	3.2	%
Weighted average grant date fair value	$6.73		$6.36	

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.

Information regarding the Restated SOP activity for the three years ended December 31, 2012 is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value (In millions)
Balance outstanding, Dec. 31, 2009	484,935	$39.57	$2.7

Granted	119,750	44.25	n/a
Exercised	(111,525)	39.01	0.9
Forfeited	(2,700)	43.00	n/a
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
Exercisable, Dec. 31, 2012	366,887	41.16	1.2

In the year ended December 31, 2012, cash of $0.7 million was received for option shares exercised and $0.1 million related tax benefit was realized. For the years ended December 31, 2012, 2011, and 2010, the total fair value of options that vested was $0.6 million, $0.6 million and $0.5 million, respectively. The weighted average remaining life of options exercisable and outstanding at December 31, 2012 was 5.1 years and 5.8 years, respectively. As of December 31, 2012, there was $0.5 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 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 $21,244 worth of stock through payroll deductions over a 12-month period, with shares issued at the end of the 12-month subscription period.

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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	2012	2011	2010
Operations and maintenance expense, for stock-based compensation	$1,668	$1,477	$1,032
Income tax benefit	(707)	(597)	(418)
Net stock-based compensation effect on net income	$961	$880	$614
Amounts capitalized for stock-based compensation	$294	$261	$182

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, 2012 and 2011, the amounts of commercial paper debt outstanding were $190.3 million and $141.6 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, 2012, our commercial paper had a maximum maturity of 254 days and an average maturity of 84 days. There were no bank loans outstanding at December 31, 2012 or 2011.

On December 20, 2012, NW Natural entered into a five year $300 million credit agreement. The agreement has a maturity date of December 20, 2017, pursuant to which we may extend commitments for two additional one-year periods subject to lender approval. 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. NW Natural's prior $250 million agreement, dated May 31, 2007, was terminated upon the closing of this new credit agreement. There were no outstanding balances under the agreement and no letters of credit issued or outstanding at December 31, 2012 and 2011.

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, 2012 and 2011.

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. 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, 2017 amount to: none in 2013; $60 million in 2014; $40 million in 2015; $65 million in 2016; and $40 million in 2017.

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The following table presents our debt outstanding as of December 31, 2012, 2011, and 2010:

In thousands	2012	2011
First Mortgage Bonds		
6.665% Series B due 2011	$—	$—
7.13 % Series B due 2012	—	40,000
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
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	—
	651,700	641,700
Subsidiary Senior Secured Debt		
Gill Ranch debt due 2016	40,000	40,000
	691,700	681,700
Less: Current maturities of long-term debt	—	40,000
Total long-term debt	$691,700	$641,700

First Mortgage Bonds
NW Natural issued $50 million of FMBs in October 2012 with a coupon rate of 4.00% and a maturity date of October 31, 2042. In September 2011, the utility issued $50 million of FMBs due September 15, 2021.

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, 2012, 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, initially $4 million, 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, 2012.

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	2012	2011
Carrying amount	$691,700	$681,700
Estimated fair value	$834,664	808,724

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8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain qualified non-contributory defined benefit pension plans covering a majority of our utility employees with more than one year of service, 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. We will begin to refer to these plans as one plan in future filings. 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, for the years ended December 31, 2012 and 2011, and a summary of the funded status and amounts recognized in the consolidated balance sheets using measurement dates as of December 31, 2012 and 2011:

	Postretirement Benefit Plans			
	Pension Benefits		Other Benefits	
In thousands	2012	2011	2012	2011
Reconciliation of change in benefit obligation:				
Obligation at January 1	$391,127	$339,338	$30,049	$27,676
Service cost	8,047	7,122	592	614
Interest cost	17,295	18,134	1,267	1,404
Net actuarial (gain) or loss	37,615	44,802	3,182	2,225
Benefits paid	(18,195)	(18,269)	(1,971)	(1,870)
Obligation at December 31	$435,889	$391,127	$33,119	$30,049
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$215,970	$219,014	$—	$—
Actual return on plan assets	26,683	(6,684)	—	—
Employer contributions	25,145	21,909	1,971	1,870
Benefits paid	(18,195)	(18,269)	(1,971)	(1,870)
Fair value of plan assets at December 31	$249,603	$215,970	$—	$—
Funded status at December 31	$(186,286)	$(175,157)	$(33,119)	$(30,049)

Our qualified defined benefit pension plan has an aggregate benefit obligation of $404.0 million and $362.9 million at December 31, 2012 and 2011, respectively, and fair values of plan assets of $249.6 million and $216.0 million, respectively.

The following table presents amounts recognized in regulatory assets or in the statement of comprehensive income for the years ended December 31, 2012, 2011 and 2010:

	Regulatory Assets						Other Comprehensive Income		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2012	2011	2010	2012	2011	2010	2012	2011	2010
Net actuarial loss	$26,504	$66,404	$17,115	$3,182	$2,225	$2,387	$3,511	$2,948	$1,716
Amortization of:									

Transition obligation	—	—	—	(411)	(411)	(411)	—	—	—
Prior service cost	(230)	(230)	(230)	(197)	(197)	(197)	35	(122)	43
Actuarial loss	(14,482)	(10,731)	(6,740)	(435)	(289)	(131)	(1,150)	(854)	(707)
Total	$11,792	$55,443	$10,145	$2,139	$1,328	$1,648	$2,396	$1,972	$1,052

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The following table presents amounts recognized in regulatory assets and accumulated other comprehensive income (AOCI) at December 31, 2012 and 2011:

	Regulatory Assets				AOCI	
	Pension Benefits		Other Postretirement Benefits		Pension Benefits	
In thousands	2012	2011	2012	2011	2012	2011
Net transition obligation	$—	$—	$—	$411	$—	$—
Prior service cost	1,097	1,328	882	1,079	(12)	(48)
Net actuarial loss	188,278	176,255	9,681	6,934	15,327	12,966
Total	$189,375	$177,583	$10,563	$8,424	$15,315	$12,918

In 2013, an estimated $17.2 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $16.8 million of actuarial losses, and $0.4 million of prior service costs. A total of $1.3 million will be amortized from AOCI 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 our common stock. 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, 2012:

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	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 $31.9 million and $28.2 million at December 31, 2012 and 2011, respectively. These plans are not subject to regulatory deferral, and the changes in actuarial gains and losses, prior service costs and transition assets or obligations are recognized in AOCI under common stock equity, 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.

Our plans for providing postretirement benefits, other than pensions, also 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 were recognized as a regulatory asset.

Net periodic benefit costs consist of service costs, interest costs, 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.

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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, 2012, 2011, and 2010 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2012	2011	2010	2012	2011	2010
Service cost	$8,047	$7,122	$6,688	$592	$614	$588
Interest cost	17,295	18,134	18,029	1,267	1,404	1,436
Expected return on plan assets	(19,082)	(17,867)	(18,207)	—	—	—
Amortization of transition obligations	—	—	—	411	411	411
Amortization of prior service costs	195	352	187	197	197	197
Amortization of net actuarial loss	15,631	11,584	7,447	435	289	131
Net periodic benefit cost	22,086	19,325	14,144	2,902	2,915	2,763
Amount allocated to construction	(5,820)	(4,905)	(3,729)	(882)	(878)	(904)
Amount deferred to regulatory balancing account[1]	(7,876)	(6,008)	—	—	—	—
Net amount charged to expense	$8,390	$8,412	$10,415	$2,020	$2,037	$1,859

[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		
	2012	2011	2010	2012	2011	2010
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	4.51 %	5.49 %	6.01 %	4.33 %	5.16 %	5.78 %
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	8.00 %	8.25 %	8.25 %	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	3.85 %	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

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2012 were 8.5% for medical and 10.5% for prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 5.0% by 2023.

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	$65	$(58)

Effect on the accumulated postretirement benefit obligation	943	(841)

The impact of a change in retirement benefit costs on operating results would be less than the amounts shown above because 30% to 40% of these amounts would be capitalized to utility plant as payroll overhead charges to construction work orders, and a certain amount of increases or decreases would be recorded to the regulatory balancing account for pensions, with the remaining amount recognized in current earnings.

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The following table provides information regarding employer contributions and benefit payments for the two qualified pension plans, non-qualified pension plans and other postretirement benefit plans for the years ended December 31, 2012 and 2011, and estimated future contributions and payments:

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2011	$22,325	$1,870
2012	25,559	1,971
2013 (estimated)	13,803	2,004
Benefit Payments:		
2010	18,645	1,476
2011	18,269	1,870
2012	18,195	1,971
Estimated Future Benefit Payments:		
2013	19,732	2,004
2014	20,244	2,080
2015	20,788	2,108
2016	21,490	2,169
2017	22,245	2,213
2018-2022	128,609	11,514

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). 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. Our qualified defined benefit pension plans are currently underfunded by $154.4 million at December 31, 2012. Including the impacts of MAP-21, we expect to make contributions during 2013 of up to $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 $0.4 million in 2012, 2011, and 2010 which is approximately 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 can withdraw from the Western States Plan at any time. However, if the plan is underfunded at the time we withdraw, we would be assessed a withdrawal liability. In accordance with accounting rules for multiemployer plans, we have not recognized these potential withdrawal liabilities on the balance sheet. Currently, we have no intent to withdraw from the plan, so we have not recorded a withdrawal liability.

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 2012, $2.4 million in 2011, and $2.1 million in 2010. 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.

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 published net asset value (NAV). The level 2 assets consist of a mutual fund where NAV is not publicly 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

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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 publicly 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 MARKET EQUITY. These are level 1 assets representing mutual funds with published NAV's. These mutual funds are valued at NAV. 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 publicly published. 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 a published NAV. This mutual fund is valued at 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 publicly 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 published NAV. This mutual fund is valued at 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 published NAV. This mutual fund is valued at 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 publicly 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 a published NAV. This mutual fund is valued at NAV. This asset class includes an investment in a broad range of assets and strategies primarily including fixed income and equity securities, along with commodities.

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 net asset value 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 as of December 31, 2012 and 2011:

In thousands	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, 2011			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$36,236	$—	$—	$36,236
U.S. small/mid cap equity	—	27,310	—	27,310
Non-U.S. equity	22,158	11,587	—	33,745
Emerging markets equity	10,208	—	—	10,208
Fixed income	19,121	—	—	19,121
Long government/credit	—	18,897	—	18,897
Real estate funds	—	—	15,317	15,317
Absolute return strategy	—	30,475	—	30,475
Real return strategy	15,475	—	—	15,475
Cash and cash equivalents	—	9,290	—	9,290
Total investments	$103,198	$97,559	$15,317	$216,074

	December 31,	
Receivables	2012	2011
Accrued interest and dividend income	$388	$414
Due from broker for securities sold	4,459	321
Total receivables	$4,847	$735
Liabilities		
Due to broker for securities purchased	$935	$839
Total investment in retirement trust	$249,603	$215,970

Level 3 Investments

The following table presents the beginning balance, activity and ending balance of Level 3 investments that have their fair values established using significant unobservable inputs as of December 31, 2012:

	Level 3 Assets
In thousands	Real Estate Funds
January 1, 2012 balance	$15,317
Sales	(15,317)
December 31, 2012 balance	$—

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9. INCOME TAX

A reconciliation between income taxes calculated at the statutory federal tax rate and the provision for income taxes reflected in the consolidated financial statements is as follows:

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Dollars in thousands	2012	2011	2010
Income taxes at federal statutory rate	$36,386	$37,550	$42,745
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,773	4,945	5,803
Amortization of investment and energy tax credits	(350)	(442)	(525)
Differences required to be flowed-through by regulatory commissions	1,718	1,647	1,647
Gains on company and trust-owned life insurance	(800)	(786)	(715)
Regulatory asset impairment	2,700	—	—
Other, net	(323)	468	507
Total provision for income taxes	$44,104	$43,382	$49,462
Effective tax rate	42.4%	40.4%	40.5%

The increase in the effective income tax rate for 2012 compared to the same period in 2011 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 amounts resulting from the 2009 Oregon tax rate change.

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

In thousands	2012	2011	2010
Current			
Federal	$1,693	$130	$(28,592)
State	99	(929)	1,441
	1,792	(799)	(27,151)
Deferred			
Federal	31,767	35,481	69,159
State	10,545	8,700	7,454
	42,312	44,181	76,613
Total provision for income taxes	$44,104	$43,382	$49,462
Total income taxes paid	$2,979	$1,756	$22,600

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

In thousands	2012	2011	2010
Regulated utility:			
Current	$1,909	$(4,646)	$(1,464)
Deferred	39,864	50,152	47,741
Deferred investment and energy tax credits	(350)	(422)	(525)
	41,423	45,084	45,752
Non-utility business segments:			
Current	(117)	3,846	(25,687)
Deferred	2,798	(5,548)	29,397

	2,681	(1,702)	3,710
Total provision for income taxes	$44,104	$43,382	$49,462

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	2012	2011
Deferred tax liabilities:		
Plant and property	$322,527	$292,235
Regulatory adjustment for income taxes paid	—	2,106
Regulatory income tax assets	60,253	65,755
Regulatory liabilities	51,424	35,638
Non-regulated deferred tax liabilities	43,824	43,373
Total	$478,028	$439,107
Deferred tax assets:		
Regulatory assets	$(7,724)	$4,727
Unfunded pension and postretirement obligations	6,024	5,119
Non-regulated deferred tax assets	(1,235)	1,161
Alternative minimum tax credit carryforward	1,986	1,626
Loss and credit carryforwards	32,997	14,255
Total	32,048	26,888
Deferred income tax liabilities, net	445,980	412,219
Deferred investment tax credits	624	990
Deferred income taxes and investment tax credits	$446,604	$413,209

We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2012.

On December 17, 2010, President Obama signed into law the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act), 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 (“the Act”). This Act extended 50% bonus depreciation under §168(k) through 2013 for MACRS property with a recovery period of 20 years or less.

The Company estimates that it has net operating loss (NOL) carryforwards to 2013 of $83.4 million for federal and $76.6

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million for Oregon. 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 the Company's consolidated balance sheet. As of December 31, 2012, we had no reserves for uncertain tax positions.

The Company settled the Oregon Department of Revenue (ODOR) 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. As of December 31, 2012, the Company is subject to examination by the Internal Revenue Service for the years 2009 through 2012.

Interest and penalties related to any future income tax deficiencies are recorded within income tax expense in the consolidated statements of 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	2012	2011
Utility plant in service	$2,435,886	$2,323,467
Utility construction work in progress	46,831	36,051
Less: Accumulated depreciation	789,201	749,603
Utility plant, net	1,693,516	1,609,915
Non-utility plant in service	296,781	293,205
Non-utility construction work in progress	6,510	8,379
Less: Accumulated depreciation	23,195	17,623
Non-utility plant, net	280,096	283,961
Total property, plant, and equipment	$1,973,612	$1,893,876

The weighted average depreciation rate for utility assets was 2.8% in 2012, 2011, and 2010. The weighted average depreciation rate for non-utility assets was 2.2% in 2012 and 2011, and 2.5% in 2010.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $281.2 million and $267.4 million at December 31, 2012 and 2011, 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 agreements with 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 4% of our gas supplies for the year ended December 31, 2012. The following table outlines our net gas reserves investment at December 31:

In thousands	2012	2011
Gas reserves, current	$14,966	$4,463
Gas reserves, non-current	92,179	48,597
Less: Accumulated amortization	7,486	1,146
Total gas reserves	99,659	51,914
Less: Deferred taxes on gas reserves	28,329	15,630
Net investment in gas reserves	$71,330	$36,284

Variable Interest Entity Analysis

We concluded that the arrangement with Encana qualifies as a variable interest entity (VIE), but that we are not the primary beneficiary of these activities as defined by the authoritative guidance related to consolidations due to the fact that our interest represents a minor portion of total extraction activities. We account for our investment in this VIE on the cost basis, and it is included under gas reserves on our balance sheet. Our maximum loss exposure related to this VIE is limited to our current investment balance.

12. INVESTMENTS

Investments include financial investments in life insurance policies, which are accounted for at fair value, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity or cost methods. The following table summarizes our other investments at December 31:

In thousands	2012	2011
Investments in life insurance policies	$51,439	$51,911
Investments in gas pipeline joint ventures	14,216	14,340
Other	2,012	2,012
Total other investments	$67,667	$68,263

Investment in Life Insurance Policies

We have invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term

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employee and director benefit plan liabilities. The amount in the above table is reported as 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 and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

Variable Interest Entity Analysis

PGH is a development stage VIE. As of December 31, 2012, 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 to the project since this impairment, and we have determined that our remaining equity investment was not impaired at December 31, 2012 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2012. 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 swap, option and combinations of option contracts for the purpose of hedging natural gas. We primarily use these derivative financial instruments to manage commodity price variability related to our natural gas purchase requirements. A small portion of our derivative hedging strategy involves foreign currency exchange transactions related to purchases of natural gas from Canadian suppliers.

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

	At December 31,	
Dollars in thousands	2012	2011
Open position absolute notional amount:		
Natural gas (in millions of therms)	39.5	35.9
Foreign exchange	$13,231	$12,313

Derivatives entered into prudently for future gas years prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate is set for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for either an 80% or 90% deferral of any gains and losses as regulatory assets or liabilities, with the remaining 10% or 20% recognized in current income. All of our commodity hedging for the 2012-13 gas year was completed prior to the start of the gas year, and these hedge prices were included in the Company's PGA filing.

Certain natural gas purchases from Canadian suppliers are payable in Canadian dollars, including both commodity and demand charges, which expose us to adverse changes in foreign currency rates. Foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for our commodity and commodity-related demand charges paid in Canadian dollars. Foreign currency contracts for commodity costs are purchased on a month-to-month basis because the Canadian cost is priced at the average noon-day exchange rate for each month. Foreign currency contracts for demand costs have terms ranging up to 12 months. The gains and losses on the shorter-term currency contracts for commodity costs are recognized immediately in cost of gas. The gains and losses on the currency contracts for demand charges are not recognized in current income because they are subject to a regulatory deferral tariff and, as such, are recorded as a regulatory asset or liability. The mark-to-market adjustment at December 31, 2012 was an unrealized gain of $0.1 million. This unrealized gain is subject to regulatory deferral and, as such, was recorded as a derivative instrument, which is offset by recording a corresponding amount to a regulatory liability account.

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Derivative hedge contracts are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2012, all of our derivatives were effective economic hedges and either qualified or were expected to qualify for regulatory deferral or hedge accounting treatment. The effectiveness test applied to financial derivatives is

dependent on the type of derivative and its use. We use the hypothetical derivative method under accounting standards for derivatives and hedging to determine the hedge effectiveness for our interest rate swaps and the dollar offset method for other derivative contracts under accounting standards for derivatives and hedging. All derivatives were effective as of December 31, 2012.

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments for the years ended December 31, 2012 and 2011. All of our currently outstanding derivative instruments are related to regulated utility operations as illustrated by the derivative gains and losses being deferred to balance sheet accounts in accordance with regulatory accounting standards.

	2012		2011	
In thousands	Natural gas commodity(1)	Foreign exchange (2)	Natural gas commodity(1)	Foreign exchange (2)
Cost of sales	$(5,850)	$—	$(60,799)	$—
Other comprehensive income (loss)	—	65	—	(201)
Less:				
Amounts deferred to regulatory accounts on balance sheet	5,850	(65)	60,799	201
Total impact on earnings	$—	$—	$—	$—

(1) Unrealized gain (loss) from natural gas commodity hedge contracts is recorded in cost of sales and reclassified to regulatory deferral accounts on the balance sheet.
(2) Unrealized gain (loss) from foreign exchange forward purchase contracts is recorded in other comprehensive income, and reclassified to regulatory deferral accounts on the balance sheet.

No collateral was posted with or by our counterparties as of December 31, 2012 or 2011. 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 2011 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 contracts outstanding, which reflect unrealized losses of $5.8 million at December 31, 2012, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$—	$—	$—	$—	$1,623
Without Adequate Assurance Calls	$—	$—	$—	$—	$1,457

As of December 31, 2012 and 2011, we realized net losses of $70.2 million and $56.5 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts.

We are exposed to derivative credit 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

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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 derivatives at December 31, 2012 currently does not extend beyond February 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 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, 2012. As of December 31, 2012 and 2011, the fair value was a liability of $5.8 million and $61.0 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, 2012 and 2011.

14. COMMITMENTS AND CONTINGENCIES

Leases

We lease land, buildings and equipment under agreements that expire in various years through 2108. Rental expense under operating leases was $4.8 million, $5.4 million and $5.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. The table below reflects the future minimum lease payments due under non-cancelable leases at December 31, 2012. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, vehicles and computer equipment.

In thousands	Operating leases	Capital leases	Minimum lease payments
2013	$5,415	$547	$5,962
2014	5,655	335	5,990
2015	5,498	136	5,634
2016	5,478	42	5,520
2017	5,474	1	5,475
Thereafter	33,187	—	33,187
Total	$60,707	$1,061	$61,768

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, 2012:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2013	$104,443	$90,823	$3,464
2014	12,166	86,119	—
2015	—	72,707	—
2016	—	61,398	—
2017	—	48,503	—
Thereafter	—	240,929	—
Total	116,609	600,479	3,464
Less: Amount representing interest	129	87,263	—
Total at present value	$116,480	$513,216	$3,464

Our total payments for fixed charges under capacity purchase agreements were $94.3 million in 2012, $94.2 million in 2011, and $91.4 million in 2010. Included in the amounts were reductions for capacity release sales of $4.2 million for 2012, $3.1 million for 2011, and $4.2 million for 2010. 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.

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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.

Environmental site remediation costs are deferred under regulatory approval from the OPUC and WUTC. In addition, the OPUC authorized an SRRM that allows the Company to recover prudently incurred environmental site remediation costs, subject to an earnings test that will be defined in a future proceeding. Actual cost recovery under SRRM will depend upon future insurance recoveries, future expenditures, annual prudence reviews, and the impacts of any earnings test the OPUC may adopt in a subsequent proceeding. 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 Item 3. Legal Proceedings). NW Natural seeks damages in excess of $50 million in losses it has incurred to date, as well as declaratory relief for additional losses it expects to incur in the future.

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other noncurrent liabilities on the balance sheet at December 31:

	Current Liabilities		Non-Current Liabilities	
Thousands	2012	2011	2012	2011
Portland Harbor site:				
Gasco/Siltronic Sediments	$2,207	$1,614	$36,087	$35,797
Other Portland Harbor	1,767	1,893	3,160	7,066
Gasco Upland site	18,722	14,092	5,028	8,900
Siltronic Upland site	637	887	379	128
Central Service Center site	140	—	396	495
Front Street site	993	1,697	—	—
Oregon Steel Mills	—	—	185	120
Total	$24,466	$20,183	$45,235	$52,506

In addition, 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:

Thousands	2012	2011
Cash paid	$71,124	$55,553
Total regulatory asset deferral[1]	126,482	105,670

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

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 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 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

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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 EPA to evaluate and design specific remedies for sediments adjacent to the Gasco upland and 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 $38.3 million to $350 million. We have recorded a liability of $34.0 million for the sediment clean-up, which reflects the low end of the EE/CA range. We have recorded an additional liability of $4.3 million for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

Other Portland Harbor. NW Natural incurs costs related to its membership in the LWG which is performing the RI/FS for EPA. NW Natural also incurs costs related to natural resource damages. In 2008, the Portland Harbor Natural Resource Trustee Council advised a number of potentially responsible parties that it intended to pursue natural resource damage claims at the Portland Harbor Superfund site. The Company and other parties have signed a cooperative agreement with the Natural Resource Trustees to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. We have accrued a liability for these claims which is at the low end of the range of the potential liability. 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 1956 (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 this portion of the site remediation which is at the low end of the range of potential liability.

In 2012, ODEQ approved our final design remediation plan for the groundwater source control portion and we began construction in October 2012. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding the effectiveness of the source control system, we have

estimated a range of liability between $14 million and $30 million, for which we have recorded an accrued liability which is at the low end of the range of the potential liability. We are uncertain about the range due to potential additional ODEQ requirements and actions needed to meet those requirements, including uncertainty about how to meet the agreed standards set by ODEQ subsequent to the initial testing of the system and as part of the final remedy for the upland portion of the Gasco site.

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 and the high end of the range cannot be reasonably estimated.

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 in which releases of hazardous substances have been confirmed 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 as we would expect to receive insurance recovery or rate recovery. See also Part II, Item 1, “Legal Proceedings.”

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

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NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Quarter ended			
In thousands, except share data	March 31	June 30	Sept. 30	Dec. 31
2012				
Operating revenues	$309,639	$103,991	$87,501	$229,476
Net income (loss)	40,607	1,409	(10,558)	28,397
Basic earnings (loss) per share[1]	1.52	0.05	(0.39)	1.06
Diluted earnings (loss) per share[1]	1.51	0.05	(0.39)	1.05
2011				
Operating revenues	$315,133	$157,354	$90,916	$264,652
Net income (loss)	40,773	2,193	(8,312)	29,244
Basic earnings (loss) per share[1]	1.53	0.08	(0.31)	1.09
Diluted earnings (loss) per share[1]	1.53	0.08	(0.31)	1.09

[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.

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

COLUMN A	COLUMN B	COLUMN C Additions		COLUMN D Deductions	COLUMN E
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
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
2010					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$3,125	$1,717	$—	$1,892	$2,950

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, 2012 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 23, 2013 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 23, 2013 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2012	Positions held during last five years
Gregg S. Kantor	55	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	51	Executive Vice President Operations and Regulation (2013-); Senior Vice President and Chief Financial Officer (2004-2013).
Margaret D. Kirkpatrick	58	Senior Vice President and General Counsel (2013-); Vice President and General Counsel (2005-2013).
Lea Anne Doolittle	57	Senior Vice President and Chief Administrative Officer (2013-); Senior Vice President (2008-); Vice President, Human Resources (2000-2007).
J. Keith White	59	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	59	Vice President, Utility Services (2007-); Director of Utility Operations, Districts and Managed Labor Relations (2004-2006).
Grant M. Yoshihara	57	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
C. Alex Miller	55	Vice President Regulation and Treasurer (2013-); Vice President, Finance and Regulation (2009-2013); Assistant Treasurer (2008-); General Manager of Rates and Regulatory Affairs (2002-2009).
Stephen P. Feltz	57	Senior Vice President and Chief Financial Officer (2013-); Assistant Secretary (2007-); Treasurer and Controller (1999-2013).
MardiLyn Saathoff	56	Vice President Legal, Risk and Land (2013-); Deputy General Counsel (2010-2013); Chief Governance Officer and Corporate Secretary (2008-); Chief Compliance Officer and Assistant General Counsel, Tektronix, Inc. (2005-2008).
David A. Weber	53	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 23, 2013. 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.

ITEM 11. EXECUTIVE COMPENSATION

The information concerning “Executive Compensation” and “Report of the Organization and Executive Compensation Committee” contained in our definitive Proxy Statement for the May 23, 2013 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2012 is reflected in Part III, Item 10, above.

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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, 2012 (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)	114,707	n/a	451,922
LTIP Restricted Stock Units (Target Award)(1)(2)	24,864	n/a	451,922
LTIP Stock Options(2)	—	—	250,000
Restated Stock Option Plan	529,925	$42.22	—
Employee Stock Purchase Plan	17,560	39.56	120,238
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)(3)	2,748	n/a	n/a
Directors Deferred Compensation Plan (DDCP)(3)	59,324	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)(4)	125,282	n/a	n/a
Total	874,410		822,160

(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-based awards outstanding at December 31, 2012, the number of shares shown in column (a) would increase by 114,707 shares and the number of shares shown in column (c) would decrease by the same amount of shares.

(2) The aggregate 451,922 shares available for future issuance under the LTIP as Restricted Stock Units or Performance Share Awards are also available for issuance of LTIP Stock Options. Therefore, a total of 701,922 shares are available for LTIP Stock Option issuance at December 31, 2012. The 250,000 shares available for LTIP Stock Options at December 31, 2012 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. 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 or 10 years as elected by the participant in accordance with the terms of the DCP. 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" contained in our definitive Proxy Statement for the May 23, 2013 Annual Meeting of Shareholders is incorporated herein by reference.

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

The information captioned "Transactions with Related Persons" and "Corporate Governance" in the Company's definitive Proxy Statement for the May 23, 2013 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2012 and 2011 Audit Firm Fees" in the Company's definitive Proxy Statement for the May 23, 2013 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 93.

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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: March 1, 2013

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	March 1, 2013
/s/ Stephen P. Feltz Stephen P. Feltz Senior Vice President and Chief Financial Officer	Principal Financial Officer	March 1, 2013
/s/ Brody J. Wilson Brody J. Wilson Acting Controller	Principal Accounting Officer	March 1, 2013
/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	)))
/s/ C. Scott Gibson C. Scott Gibson	Director	))

		March 1, 2013
/s/ Tod R. Hamachek	Director	)
Tod R. Hamachek		)
		)
/s/ Jane L. Peverett	Director	)
Jane L. Peverett		)
		)
/s/ George J. Puentes	Director	)
George J. Puentes		)
		)
/s/ Kenneth Thrasher	Director	)
Kenneth Thrasher		)

NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Annual Report on Form 10-K
For the Fiscal Year Ended December 31, 2012

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).

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.
*10s.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2010-2012) (incorporated herein by reference to Exhibit 10t. to Form 10-K for 2011, File No. 1-15973).
*10t.	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).
*10u.	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).
10v.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2013-2015).
*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).
*10y.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan relating to a special award to an executive officer (incorporated herein by reference to Exhibit 10z. to Form 10-K for 2009, File No. 1-15973).
10aa.	Form of Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan (2013).
*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.	Annual Incentive Plan for NW Natural Gas Storage, LLC, as amended February 2, 2012.
10dd.	Long Term Incentive Plan for NW Natural Gas Storage, LLC.

10ee. Form of Change in Control Severance Agreement between the Company and an executive officer.

101. The following materials from Northwest Natural Gas Company Annual Report on Form 10-K for the fiscal year ended December 31, 2012, 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