NORTHWEST NATURAL GAS CO
Form 10-K
February 28, 2012

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, 2011

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, 2011, the registrant had 26,672,812 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 $1,189,774,420.

At February 24, 2012, 26,791,793 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 2012 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, 2011
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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 or one trillion Btu's.

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 sold: 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.

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 -260 degrees Fahrenheit.

Purchased gas adjustment (PGA): a regulatory mechanism for adjusting customer rates to reflect changes in the expected cost to acquire and deliver natural gas supplies.

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.

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.

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 equitable rates and balance the interests of all classes of customers and our shareholders.

Utility margin: utility gross revenues less the associated cost of gas sold, including regulatory adjustments and applicable revenue taxes. Also referred to as utility net operating revenues.

Weather normalization: a rate mechanism applied to residential and commercial customers' bills to adjust residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average.

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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;
- liquidity and financial positions;
- project development and expansion;
- competition;
- procurement and development of new gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- rate case;
- 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;
- adequacy of, 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 uncer–tainties, 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) 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, its subsidiaries and joint ventures. A reference to NW Natural ("we," "us" or "our") in this report means NW Natural and its subsidiaries and joint ventures unless otherwise noted.

### Business Segments

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 that we aggregate and report as Other.

### Local Gas Distribution

We are principally engaged in the distribution of natural gas in Oregon and southwest Washington. We refer to this business segment as our local gas distribution segment or utility. Our local gas distribution segment involves building and maintaining a safe and reliable pipeline distribution system, purchasing gas from producers and marketers, contracting for the transportation of gas over pipelines from regional supply basins to our service territory, and reselling the gas 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). Local gas distribution also includes transporting gas owned by customers from an interstate pipeline connection, or city gate, to the customers' facilities for a fee, also approved by the OPUC or WUTC. Approximately 90 percent of our consolidated assets and consolidated net income have been related to the local gas distribution segment over the last few years. The OPUC has allocated to us as our exclusive service area 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. 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 124 cities and neighboring communities in 15 Oregon counties, as well as in 16 cities and neighboring communities in three Washington counties. The city of Portland is the principal retail and manufacturing center in the Columbia River Basin, and is a major port for trade with Asia.

See Note 4 to the Consolidated Financial Statements for information on local gas distribution assets and results of operations for the years ended December 31, 2011, 2010 and 2009.

Regulation and Rates

Our utility segment is subject to regulation with respect to, among other matters, rates and systems of accounts by the OPUC, the WUTC, and Federal Energy Regulatory Commission (FERC). The OPUC and WUTC also regulate NW Natural's issuance of securities. In 2011, approximately 90 percent of our utility gas volumes were delivered to, and utility operating revenues were derived from, Oregon customers and the balance from Washington customers. . The OPUC and the WUTC generally require the natural gas commodity cost to be billed to customers at the same cost incurred or expected to be incurred by the utility. We have not historically earned a profit or incurred a loss on gas commodity purchases; however, in Oregon we have an incentive sharing provision whereby we can either increase or decrease margin revenues from gas cost variances as compared to gas costs embedded in the PGA. Under this provision, our net income is affected by differences between actual and expected purchased gas costs, which occur primarily because of market fluctuations and volatility affecting unhedged gas purchases. In addition, we recently entered into a regulatory agreement where we receive a rate base return on our investment in gas reserves. See Part II, Item 7., "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment and Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves".

We file general rate case and rate tariff requests periodically with the OPUC, WUTC and FERC to change the rates we charge our utility and storage customers. On December 30, 2011, we filed an application for a general rate increase at the OPUC. We requested an increase in authorized annual Oregon jurisdictional revenues of $43.7 million, or 6.2 percent, with an overall rate of return on capital of 8.28 percent, including a return on common equity of 10.3 percent, and an authorized equity to capitalization ratio of 50 percent. We also requested the establishment of a rate mechanism through which deferred costs related to our environmental liabilities will be recovered through rates. The new rates are requested to be effective by November 1, 2012. We expect the OPUC to make a decision on this rate case by the end of October 2012.

Our most recent general rate case in Washington was approved in December 2008, and new rates were effective on January 1, 2009 (see Part II, Item 7., "Results of Operations—Regulatory Matters—General Rate Cases," below).

We are required under our Mist interstate storage certificate authority to file with FERC every five years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for the interstate storage service. For further information, see Part II, Item 7., "Results of Operations—Regulatory Matters," and "Business Segments—Gas Storage," below.

Gas Supply

Our gas supply strategy is based on forecasted customer requirements, which considers estimated load growth by type of customer, attrition, conservation, distribution system constraints, interstate pipeline capacity and contractual limitations and the forecasted transfer of large customers between sales service and transportation-only service. We perform sensitivity analyses based on factors such as weather variations and price elasticity effects. We have a diverse portfolio of short-, medium- and long-term firm gas supply contracts that are supplemented during periods of peak demand with gas from storage facilities either owned by or contractually committed to us.

To achieve our gas supply strategy, we employ a gas purchasing strategy that emphasizes a diversity of supply sources; a diverse portfolio of contract types and durations; strategic uses of gas storage facilities and capacity recall agreements; a variety of gas cost management strategies; and physical acquisition of gas supplies.

We purchase our gas supplies at liquid trading points to facilitate competition and price transparency. These trading points include the NOVA Inventory Transfer (NIT) point in Alberta (also referred to as AECO), Huntingdon/Sumas and Station 2 in British Columbia, and multiple receipt points in the U.S. Rocky Mountains.

Diversity of Supply Sources

We purchase natural gas for our core utility customers from three supply basins located between western Canada and the U.S. Rocky Mountain areas. Currently, about 65 percent 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 the broader U.S. market prices. Additionally, we expect increased availability of gas supplies throughout North America as a result of the extraction of shale gas resources and the building of new transmission pipeline projects to increase capacity out of the U.S. Rocky Mountain region.

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Diverse Supply Portfolio of Contract Types and Durations

We maintain a diverse portfolio of short-, medium-, and long-term firm gas supply contracts. We typically enter into gas purchase contracts for:

- year-round baseload supply;
- additional baseload supply for the winter heating season;
- winter heating season contracts where we have the option to call on all or some of the supplies on a daily basis; and
- spot purchases, taking into account forecasted customer requirements, storage injections and withdrawals and seasonal weather fluctuations.

At December 31, 2011, we have contracts with gas suppliers for deliveries ranging from three months to four years, which provide for a maximum of 2.0 million therms of firm gas per day during the winter heating season and 0.7 million therms per day year-round. These contracts have a variety of pricing structures and purchase obligations. In addition, we have another 1.3 million therms per day of firm gas supplies whereby we can purchase supplies for delivery to our system during the winter heating season. During 2011, we purchased a total of 808 million therms of gas under contracts with durations outlined in the chart below.

| Contract Duration (primary term) | Percent of Purchases |
|---|---|
| Long-term (one year or longer) | 29 |
| Short-term (more than one month, less than one year) | 26 |
| 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 the independent energy marketing company (see "Gas Cost Management Strategy—Asset management," below), no individual supplier generally provides more than 10 percent of our supply requirements. In 2011, one supplier provided 11 percent of our supply requirements. Firm year-round supply contracts have remaining terms ranging from one to four years. Currently, all firm gas supply contracts use price formulas tied to monthly index prices.

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 primarily under short-term contracts. During 2011, new short-term purchase contracts were entered into with 17 suppliers, which in addition to our year- round contracts provide for a total of up to 2.0 million therms per day. We intend to enter into new purchase contracts during 2012 for roughly the same volume of gas with existing or new suppliers, as needed, to replace contracts that will expire in 2012.

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.

We continue to purchase a small amount of gas from a non-affiliated producer in the Mist gas field in Oregon. The production area is situated near our underground gas storage facilities. Current production supplies are less than 2 percent of our total annual purchase requirements. Production from these wells varies as existing wells are depleted and new wells are drilled.

In 2011, we entered into an agreement with Encana Oil & Gas (USA) Inc. (Encana) to develop physical gas reserves that are expected to supply a portion of our utility customers' requirements over the next 30 years. The volume of gas produced and allocated to us under the agreement will increase in the early years as we continue to invest in drilling, with volumes expected to peak at about 13 percent of our utility's gas supply requirement in gas year 2015-2016. Over the first 10 years of the agreement (2011-2020), volumes are expected to average approximately 8 to 10 percent of the annual gas purchase requirements of our utility customers. In 2011, volumes from gas reserves were less than one percent of our annual gas purchases.

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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 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 2011, a total of 100,000 therms per day of Mist storage capacity that had previously been available for non-utility gas storage services was recalled and committed to use for core utility customers. There was no Mist recall in 2010, but 100,000 therms per day were recalled in May 2009. The core utility currently has 2.6 million therms per day of deliverability and approximately 9.5 Bcf of working gas capacity available at the Mist storage facility.

We also have contracts with Northwest Pipeline (Northwest Pipeline), a subsidiary of The Williams Companies, for firm gas storage from an underground facility at Jackson Prairie near Chehalis, Washington, that provides us with daily firm deliverability of about 0.5 million therms and total seasonal capacity of about 11.2 million therms. 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.

We also contract for storage service in Alberta for amounts totaling just under 20 million therms. 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.

LNG storage. We own and operate two LNG storage facilities in our Oregon service territory that liquefy gas for storage during the summer months so that it is available for withdrawal during periods of peak demand in the winter heating season. These two facilities provide a maximum combined daily deliverability of 1.8 million therms and a total seasonal capacity of 16 million therms. 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 4.8 million therms.

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 core utility customers primarily consists of the purchase price paid to suppliers (including the cost to acquire supplies in the form of gas reserves), charges paid to pipeline companies to store and transport gas to our distribution system, and gains or losses related to gas commodity hedge contracts entered into in connection with the purchase of gas for core utility customers.

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While volatility in natural gas commodity prices has ebbed and flowed over the last several years due to a number of factors, recent success in new drilling technologies and substantial new supplies from shale gas formations around the U.S. and Canada have resulted in increased North American supplies of natural gas and lower gas prices. At the same time, pipeline transportation rates charged by Canadian pipelines and U.S. interstate pipeline transportation service providers have been relatively stable over the last several years, due in part to a 2006 rate case settlement for the U.S. interstate pipelines. 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. Pipeline transportation rate increases or decreases are generally passed on to our customers through annual PGA updates.

We engage in 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 instruments that effectively convert the floating index price in a physical gas supply contract to a fixed price (referred to as commodity price swaps);
- negotiating financial derivative instruments that effectively set a ceiling or floor price, or both, on a floating price physical supply contract (referred to as commodity price options such as calls, puts, and collars);
- buying gas and injecting it into storage;
- buying a physical supply of gas reserves for longer term price stability; and
- using an asset management service provider to produce revenues that reduce our utility's net cost of gas sold;

Fixed-price contracts. We negotiate fixed price contracts directly with gas suppliers for a portion of our gas purchases. When we enter into these fixed-price contracts with our suppliers, the price is typically set based on the prevailing index price plus or minus a spread based on the forward price curve of natural gas at that time.

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 variety of investment-grade credit counterparties, typically with credit ratings of AA- or higher. See Part II, Item 7A., "Quantitative and Qualitative Disclosures About Market Risk—Credit Risk—Credit exposure to financial derivative counterparties." 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.

Storage supplies. We seek to mitigate the effects of higher gas commodity prices and price volatility on core utility customers by using our underground gas storage facilities, LNG facilities and other methods of gas storage strategically in an attempt to manage the cost of gas commodity purchases. We purchase and inject gas into storage during the summer months when demand and gas prices are generally lower. About 19 percent of our annual gas supply requirements is stored for withdrawal during the winter months in five different market-area storage facilities and one contract for supply-basin storage. We are able to draw on these supplies during peak demand, thereby reducing the need for higher-priced spot gas purchases.

Gas reserves. In addition to hedging gas prices with financial derivative instruments and gas storage, we recently signed an agreement with Encana to acquire physical gas supplies to provide a portion of our core utility customers' requirements over 30 years. During the first 10 years of the agreement, we believe the volumes of gas received under the Encana agreement will provide approximately 8 to 10 percent of the average annual requirements of our utility customers.

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 in this regard. 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 provides cost savings that reduces our utility's cost of gas sold, and generates incremental revenues from a regulatory incentive-sharing mechanism that are included in our gas storage business segment.

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Gas Distribution Operations

The goals of our gas distribution operations for core utility customers are:

- Safety—Building and maintaining a safe pipeline distribution system;
- Reliability—Ensuring a gas resource portfolio that is sufficient to satisfy core utility customer requirements under extremely cold weather conditions;
- Lowest reasonable cost—Applying strategies to acquire gas supplies at the lowest reasonable cost for utility customers;
- Price stability—Making the best use of physical assets and financial instruments to manage commodity price volatility; and
- Cost recovery—Managing gas purchase costs prudently to minimize the risks associated with regulatory review and recovery of gas acquisition costs.

Safety

Safety and protection of our employees, our customers and the public at large is 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 system integrity programs 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 regulatory oversight of the safety of their operations. The "Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011" signed into law in early 2012, requires 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, requirements for operators to reverify the maximum allowable operating pressures for transmission pipelines, and other requirements. We intend to work diligently with industry associations and federal and state regulators to comply with all new laws and regulations. We expect that costs associated with compliance with 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. For this purpose, we develop a composite design year and include 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. We also assume that all usage by interruptible customers will be curtailed on the design day. Our projected sources of delivery for design day firm utility customer sendout total approximately 9.2 million therms. Of this total, we are currently capable of meeting nearly 60 percent 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. Optimal utilization of storage on our design day reduces the cost and dependency on firm interstate pipeline transportation. 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. That January 2004 cold weather event lasted about 10 days, and the actual firm customer sendout each day provided data that confirmed our load forecasting models with little re-calibration. Similar cold temperatures experienced in December 2008 and December 2009 produced very high sendout days, but firm sendout in those years was still at least 3 percent below our 2004 record. Accordingly, 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).

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The following table shows the sources of supply that are projected to be used to satisfy the design day sendout for the 2011-2012 winter heating season:

Projected Sources of Utility Supply for Design Day Sendout

| Sources of Utility Supply | Therms (in millions) | Percent |
|---|---|---|
| Firm supply purchases | 3.3 | 36 |
| Mist underground storage (utility only) | 2.6 | 28 |
| Company-owned LNG storage | 1.8 | 20 |
| Off-system firm storage contracts | 1.1 | 12 |
| Recall agreements | 0.4 | 4 |
| Total | 9.2 | 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 changes, and establish a plan for getting 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 prudency 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 prudency review. We filed our 2011 IRP with Oregon in January 2011, and with Washington in March 2011. Subsequent to these filings, we filed a modified IRP in both states on September 1, 2011 to address new assumptions about the schedule for the east segment of the Palomar pipeline (see Part II, Item 7., “2012 Outlook-Strategic Opportunities-Pipeline Diversification,” below). The OPUC review of our 2011 IRP filing is in process.

Lowest Reasonable Cost

We apply cost management strategies, including fixed-price contracts, financial derivative instruments, storage supplies, gas reserve purchases and asset management, in seeking 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. Our gas storage 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. (See “Strategic Use of Gas Storage and Capacity Recall” above). In addition, we recently signed an agreement with Encana to acquire physical gas supplies to provide a portion of our core utility customers’ requirements over 30 years. During the first 10 years of the agreement, we believe the volumes of gas received under the Encana agreement will provide approximately 8-10 percent of the average annual requirements of our utility customers. (see “Diverse Supply Portfolio of Contract Types and Durations” above). We also mitigate year-to-year commodity price volatility through financial hedge contracts such as commodity price swaps and options. (see “Gas Cost Management Strategy—Financial derivatives instruments” above and Part II, Item 7A., “Quantitative and Qualitative Disclosures About Market

Risk—Credit Risk—Credit exposure to financial derivative counterparties.”)

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Cost Recovery

Mechanisms for gas cost recovery are designed to be fair and to balance the interests of our customers and shareholders. In general, utility rates are designed to recover the cost of, but not earn a return on, the gas commodity sold. We attempt to minimize risks associated with gas cost recovery through:

- re-setting customer rates annually for changes in forecasted gas costs and recovery of customer deferrals of prior year's actual versus forecasted gas costs (see Part II, Item 7., "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment");
- aligning customer and shareholder interests, such as through the use of our PGA incentive sharing mechanism, weather normalization, conservation, 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.

Customers

At year-end 2011, we had approximately 680,000 utility customers, consisting of approximately 616,000 residential, 63,000 commercial and 1,000 industrial customers. Approximately 90 percent of our utility customers are located in Oregon, and 10 percent are located in Washington. 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.

Competition and Marketing

Competition with Other Energy Products

We have no direct competition in our service area from other natural gas distributors. However, for residential customers we compete primarily with electricity, fuel oil, propane and renewable energy providers. We also compete with electricity, fuel oil and renewable energy for commercial applications. In the industrial market, we compete with all forms of energy, including competition from third-party sellers of natural gas commodity. Competition among energy suppliers is based on price, efficiency, reliability, performance, market conditions, technology, legislative policy, and environmental impact. Whether or not we provide the gas supplies to serve our transportation-eligible customers, our net margins are not materially affected because we generally do not make any margin on the commodity sold to our utility customers (see "Industrial Markets," below and "Regulation and Rates" above).

Residential and Commercial Markets

The relatively low market saturation of natural gas in residential single-family dwellings in our service territory, estimated at less than 60 percent, and our operating convenience and environmental advantage over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2011, the net increase in residential customers was 5,072 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 2011 was 5,546. This represents a 12-month growth rate of 0.8 percent, which is down slightly from 2010 and well below historical growth rates due to the slow economic recovery and weak job market.

On an annual basis, residential and commercial customers typically account for about 55 to 60 percent of our utility's total volumes delivered and about 85 to 90 percent of gross operating revenues, while industrial customers account for about 40 to 45 percent of volumes and about 10 percent of gross operating revenues. The remaining gross operating revenues are derived from miscellaneous services and other regulatory revenues.

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Industrial Markets

Competition to serve the industrial and large commercial market in the Pacific Northwest has been relatively unchanged since the early 1990s in terms of numbers and types of competitors. Competitors consist of gas marketers, oil/propane sellers and electric utilities.

The OPUC and WUTC have approved transportation tariffs under which we may contract with customers to deliver customer-owned gas. Transportation tariffs are priced at our sales service rate less the commodity cost included in that rate. Therefore, our transportation margins (i.e. sales minus the cost of gas sold) are generally unaffected financially if industrial customers buy commodity supplies directly from producers or marketers rather than purchasing gas from us, as long as they remain on a tariff or contract with the same level of service. Other than our incentive sharing arrangements and rate base return on gas reserves, we do not generally make any margin on the sale of the gas commodity. However, industrial customers may select between firm and interruptible service as well as other levels of service, and these choices can positively or negatively affect margin. Firm service schedules have a higher profit margin than interruptible service. The relative level and volatility of 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 have caused some industrial customers to alternate between sales and transportation service or between higher and lower levels of service. See "Regulation and Rates" above for a full discussion on incentive sharing agreements.

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

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 Northwest Pipeline's interstate pipeline system, which would allow them to bypass our local 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.

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 other options to further diversify our pipeline transportation paths. Specifically, we are jointly developing plans to build a pipeline (Palomar pipeline) that would connect TransCanada Pipelines Limited’s (TransCanada) Gas Transmission Northwest (GTN) interstate transmission line to our local gas distribution system. We entered into an agreement with GTN for the purpose of jointly developing, owning and operating this proposed pipeline. Additionally, we entered into precedent agreements to become a shipper on the Palomar pipeline. 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., “2012 Outlook—Strategic Opportunities—Pipeline Diversification”).

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Pipeline transportation agreements

We incur monthly demand charges related to the following firm pipeline contracts.  The largest of our transportation agreements with Northwest Pipeline extends through September 2018 and provides for firm transportation capacity of up to 2.1 million therms per day.  This agreement provides access to natural gas supplies in British Columbia and the U.S. Rocky Mountains.

Our second largest transportation agreement with Northwest Pipeline extends through November 2016. It provides up to 1.0 million therms per day of firm transportation capacity from the point of interconnection with Northwest Pipeline and GTN systems in eastern Oregon to our service territory.  GTN's pipeline runs from the U.S./Canadian border through northern Idaho, southeastern Washington and central Oregon to the California/Oregon border.  We have firm long-term capacity on GTN's pipeline and two upstream pipelines in Canada, which match the amount of Northwest Pipeline capacity northward into Alberta, Canada.

We also have an agreement with Northwest Pipeline that extends into 2044 for approximately 350,000 therms per day of firm transportation capacity from the U.S. Rocky Mountain region.  Additionally, in 2008 we executed an agreement with a third party to take assignment of their firm transportation contract starting January 1, 2017, with the term extending through 2046.  This contract consists of 120,000 therms per day on Northwest Pipeline from the U.S. Rocky Mountain region.

In addition, we have firm long-term pipeline transportation contracts with two other major transporters located in Canada.  One contract extends through October 2014 and provides approximately 580,000 therms per day of firm gas transportation from Station 2 in northern British Columbia to the Huntingdon/Sumas connection with Northwest Pipeline at the U.S./Canadian border.  Another contract extends through October 2020 and provides approximately 480,000 therms per day of firm transportation from southeastern British Columbia to the same Huntingdon/Sumas connection with Northwest Pipeline.  Our capacity on this second contract is matched with companion contracts for pipeline capacity on the TransCanada systems in British Columbia and Alberta, allowing purchases to be made from the gas fields of Alberta, Canada.

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, including the non-utility portion of our Mist gas storage facility near Mist, Oregon and our 75 percent ownership share of the Gill Ranch gas storage facility near Fresno, California.  Because 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, 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 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 capture market opportunities. See Note 4 for more information on gas storage assets and results of operations for the three years ended December 31, 2011.

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Regulation and Rates

Our gas storage segment is subject to regulation with respect to, among other matters, rates, terms of services, 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, and at least every five years we are required to file with FERC either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for the interstate storage service. For further information, See Part II, Item 7., "results of Operations – Regulatory Matters," below.

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 core local gas distribution customers. Since 2001, we have made gas storage capacity at Mist 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. Currently, the Mist facilities consist of seven depleted natural gas reservoirs with a combined working gas capacity of approximately 16 Bcf, a combined deliverability of approximately 0.5 Bcf per day, a central compression facility, gathering pipelines and other related facilities.

In addition to earning revenue from storage contracts, 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. In Oregon, 80 percent of the pre-tax income is retained by the gas storage segment when the costs of the capacity used have not been included in utility rates, and 33 percent of the pre-tax income is retained when the capacity costs have been included in utility rates. The remaining 20 percent and 67 percent of pre-tax income in each case are credited to a deferred regulatory account for refund to core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage services and third-party asset management activities.

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 owns a 75 percent undivided interest in this facility and is the sole operator of the facility. The Gill Ranch 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 percent of the available storage capacity at the facility. Gill Ranch's share is designed to provide 15 Bcf of working gas capacity, which we expect to be in full use by the end of 2012.

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.

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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 Storage1 | 6 | | 258 | 103 |
| Gill Ranch Storage | 15 | 2 | 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 designed to provide 15 Bcf out of a total of 20 Bcf.
3. Our share of the expected daily maximum injection and withdrawal rates.

Gas Storage Operations

Asset management. With respect to the Mist gas storage facility, we contract with an independent energy marketing company to provide asset management services for our utility pipeline transportation contracts, our utility gas supplies and our unused utility and non-utility storage assets, primarily through the use of commodity transactions and pipeline capacity release transactions (see "Facilities—Mist Gas Storage Facility," above). Similarly, we contract with an independent energy marketing company to manage the value of our unused storage assets at the Gill Ranch gas storage facility (see "Facilities—Gill Ranch Gas Storage Facility," above). The results of asset management services at both facilities 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.

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 from the management of available surplus storage capacity and related transportation capacity. Temporary surplus capacity is quite often available during the spring and summer months when the demand for gas by utility customers is low.

Although we expect much of the storage revenue at Gill Ranch to be in the form of fixed monthly demand charges, total cash flows from the Gill Ranch storage facility 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 compression is used primarily for the injection of gas rather than for withdrawal, we expect power costs to be incurred disproportionately 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 storage 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 percent of our existing non-utility gas storage capacity at Mist, with the largest customer accounting for about half of total capacity. These three customers have contracts that expire at various dates through April 2017.

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 percent 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.

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

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 storage capacity used by this business segment 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.

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. We believe the earliest timeframe for completing the next expansion is 2016. In the meantime, we expect to continue working on preliminary design and project scope, which will likely include the development of storage wells, potentially a second compression station, and additional pipeline gathering 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, Gill Ranch 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 an aggregate of 20 Bcf or 50 percent of total estimated storage capacity.

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 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 a gas transmission pipeline in Oregon (see Part II, Item 7., “2012 Outlook—Strategic Opportunities—Pipeline Diversification,” below); a minority interest in other pipeline assets held by our wholly-owned subsidiary NNG Financial; and other operating and non-operating expenses of the parent company that are not included in utility or gas storage operations. Less than 1 percent of our consolidated assets and consolidated net income are related to activities in the “Other” business segment. This pipeline is regulated by FERC. See Note 4 for summary information on this Other segment’s assets and results of operations for the three years ended December 31, 2011.

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Environmental Issues

Properties and Facilities

We have properties and facilities that 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 own, or previously owned, properties currently being investigated that may require environmental response. Based on our current assessment of regulatory and insurance recovery of environmental costs, we do not expect that the ultimate resolution of these matters will have a material adverse effect on our financial condition, results of operations or cash flows; however, if it is determined that both the insurance recovery and future rate recovery of such costs are not probable, then the costs not expected to be recovered will be charged to expense in the period such determination is made and could have a material impact on our financial condition or results of operations. See Note 15 for a further discussion of potential environmental responses, related costs and regulatory and insurance recovery.

Greenhouse Gas Issues

We recognize that our businesses are likely to be impacted by carbon constraints. A variety of legislative and regulatory measures to address greenhouse gas emissions are in various phases of discussion or implementation. These include proposed international standards, proposed federal legislation, proposed or enacted federal regulations, and proposed or enacted state actions to develop statewide or regional programs, each of which has imposed or would impose measures to achieve reductions in greenhouse gas emissions. For example, in December 2009, the EPA published its findings that concentrations of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment as drivers of climate change, and that emissions from motor vehicles contribute to that threat. Based on these findings by the EPA, the agency proceeded with the adoption and implementation of regulations to regulate emissions of greenhouse gas starting in January 2011 from new motor vehicles and from stationary sources of air pollution such as power plants and oil refineries. One of these new regulations, which the EPA refers to as the "Tailoring Rule," requires that permits held by larger sources of air pollution address greenhouse gases, and also requires additional permitting and implementation of best available control technology for limiting greenhouse gas emissions at certain new facilities and at existing facilities when they implement modifications that increase emissions of greenhouse gas above threshold levels. Lawsuits have been filed challenging the EPA's regulation of greenhouse gas emissions, and members of the U.S. Congress have discussed proposing legislation that would limit the EPA's ability to regulate 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 CO2 equivalents per year. The first reports were due on March 31, 2011 for emissions occurring on or after January 1, 2010. 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 first report under these more recent regulations is due by March 31, 2012.

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The outcome of these and other international, federal and state climate change initiatives 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 low carbon fuel standard passed in 2009, 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, 2011, the utility workforce consisted of 598 members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO, and 452 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, 2011, our subsidiaries had a combined workforce of 21 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 2012, utility capital expenditures are estimated to be between $145 and $160 million, and non-utility capital investments are estimated to be between $10 and $15 million. For the five-year period ending in 2016, capital expenditures for the utility are estimated to be between $400 and $500 million, while the amount for gas storage and other investments after 2012 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 copied at the Public Reference Room of the SEC, 100 F Street, N.E., Washington, D.C. 20549. You can obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (http://www.sec.gov) that 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.

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We have adopted a Code of Ethics for all employees and officers that is available on our website. We intend to disclose amendments to, and any waivers from the Code of Ethics on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about us are also available at the website. Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, NW Natural, One Pacific Square, 220 N.W. Second Avenue, Portland, Oregon 97209, telephone 503-226-4211 ext. 3412.

## 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 in general, and failure of regulatory authorities to approve rates which provide for timely recovery of our costs and an adequate return on invested capital in particular, or an unfavorable outcome in ratemaking 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 capital invested, the amounts and types of securities we may issue, services we provide, facilities we own or operate, terms of customer services, system of accounts, the nature of investments we may make, safety standards, deferral and recovery of various expenses, including, but not limited to, pipeline replacement and environmental remediation costs, transactions with affiliated interests, actions investors may take with respect to our company 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 the Federal Energy Regulatory Commission 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 any costs they consider unreasonable or imprudently incurred, and the rates allowed by the FERC may be insufficient for recovery of costs incurred. For example, we expect to continue to make expenditures to expand, improve and operate our utility distribution and gas storage systems. Regulators can deny such expansions or improvements or recovery of expenditures we make if they find that such expenditures were not prudently incurred according to their regulatory standards. 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.

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We filed a general rate case in Oregon on December 30, 2011. While the OPUC is required to establish rates that are fair, just and reasonable, they have significant discretion in applying this standard. The ratemaking process typically involves 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 same common objective of limiting rate increases or even reducing rates. Our rate case proposes to establish rates based on forecasted operating and capital expenditures that rely on many assumptions concerning future conditions and operating results. In the ratemaking process, regulators and interveners can challenge these assumptions and may assert different assumptions or apply different interpretations to the data. We cannot predict the ultimate outcome of any ratemaking proceeding, including the extent to which certain costs, such as significant capital projects, are recoverable; what rates of return will be allowed; and whether, or in what form, our regulatory mechanisms, such as our weather normalization mechanism or conservation tariff, will be renewed. Additionally, we may agree to conditions as part of a settlement or regulatory proceeding, or there may be determinations made in regulatory investigations, that reduce our earnings and liquidity, all of which could adversely affect our results of operations and financial condition.

Economic risk. Changes in the economy and in the financial markets may have a negative impact on our financial condition and results of operations.

Changes in economic activity in our markets and in global financial markets can result in a decline in or sustained lower levels of energy consumption, which could have a negative effect on our financial condition and results of operations. In recent years, the U.S. and world economies have slowed, credit markets have tightened, unemployment rates and mortgage defaults have risen, and the value of homes and other personal as well as business investments have declined, which has adversely affected the income and financial resources of many domestic households and businesses. It is unclear whether the federal responses, as well as international, to these conditions will lessen the severity or duration of this economic downturn, or could possibly trigger inflationary conditions. Our operations and financial results are affected by these economic conditions. Less new housing construction, fewer conversions to natural gas, fewer customer additions, higher levels of residential foreclosures and vacancies, tighter lending restrictions, higher levels of personal and business bankruptcies or reduced spending could all result in a decline in or sustained lower levels of energy 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 cost of 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. 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, disputes may arise between potentially responsible parties and regulators 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 and remediation that may be required, or disputes arising in relation thereto or the outcomes of those disputes, because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liabilities on all potentially responsible parties. This uncertainty and disputes arising therefrom could lead to 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.

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Business development risk. The development, construction, startup and operation of our business development projects may involve unanticipated changes or delays that could negatively impact our costs as well as 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 the Palomar gas transmission 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, or financing, to complete our projects in a cost-efficient or timely manner. If we do not obtain the necessary regulatory approvals in a timely manner, development projects may be delayed or abandoned. There also may be 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, natural gas storage and transportation markets are highly competitive, both within the natural gas industry and with alternative sources of energy. To fund our business development projects, we will need to secure financing from willing investors at reasonable costs. We may be unable to finance our business development projects at acceptable interest rates or within a scheduled timeframe for completing the project. One or more of these events could result in the project becoming impaired, and such impairment could have an adverse effect on our financial condition and results of operations.

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

We use joint ventures and other business arrangements to manage and diversify the risks of certain utility and non-utility development projects, including Palomar pipeline, Gill Ranch storage and Encana gas reserves. Also, we may acquire or develop part-ownership interests in other similar projects in the future. Under these types of business 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 related to a project. 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. With respect to our gas reserves venture, the drilling of new wells for gas may not produce the expected volumes of gas, or any gas. Additionally, environmental regulations may require operational improvements to mitigate potential environmental damage, increasing operating costs to us. Although we have contractual and other legal remedies to mitigate these risks and enforce our interests, dry wells, increased operational costs, or a participant in one of these business arrangements acting contrary to our interests, it could adversely impact the project as well as our financial condition, results of operations and cash flows.

Global climate change risk. Future legislation may impose carbon constraints to address global climate change, exposing us to regulatory and financial risk. Additionally, certain properties and facilities may be subject to physical risks associated with climate change.

There are a number of new 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. The adoption of current or future proposed legislation by the U.S. Congress or similar legislation by states, or the adoption of related regulations by federal or state regulatory bodies such as the EPA, imposing reporting obligations on, or limiting emissions of greenhouse gases from our equipment or operations could have far-reaching and significant impacts on our business as well as the broader energy industry. Such current or future legislation or regulation could also impose on us operational requirements or restrictions or additional charges to fund energy efficiency initiatives. 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 on us increased costs 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.

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These and other physical changes could result in changes in customer demand, increased costs associated with repairing and maintaining distribution systems resulting in increased maintenance and capital costs, increased financing needs, limits on our ability to meet peak customer demand, increased regulatory oversight, and lower customer satisfaction. Also, to the extent that climate change adversely impacts the economic health of our region, it may adversely impact customer demand and revenues. Such physical risks could have an adverse effect on 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:

Ÿ earthquakes, floods, storms, landslides and other adverse weather conditions and hazards;
Ÿ leaks or other losses of natural gas or other hydrocarbons as a result of the malfunction of equipment or facilities;
Ÿ damages from third parties, including construction, farm and utility equipment or other surface users;
Ÿ operator errors;
Ÿ 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;
Ÿ 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;
Ÿ collapse of underground storage caverns;
Ÿ migration of natural gas through faults in the rock or to some area of the reservoir where existing wells cannot drain the gas effectively;
Ÿ blowouts (uncontrolled escapes of gas from a pipeline or well) or other accidents, fires and explosions; and
Ÿ 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. Natural gas that moves outside of the effective drainage area through migration could be permanently lost and would need to be replaced. 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 and other extreme events to which we may not able to promptly respond.

Local or national disasters, pandemic illness, terrorist activities 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 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. We maintain emergency planning and training programs to remain ready to respond to events that could cause business interruption. However, 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.

We provide pension plans and postretirement healthcare benefits to most eligible full-time employees and retirees. 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 including but not limited to the Health Care Reform Act in 2010, 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 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 Office and Professional Employees International Union 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 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. Changes in regulations or the imposition of additional 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.

Environmental regulation risk. We are subject to environmental regulations 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 and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Revised environmental regulations which result in increased compliance costs or additional operating restrictions 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.

Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could adversely affect our financial results.

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. However, we anticipate companies in the natural gas distribution business may be subjected to even greater federal, state and local regulatory oversight over the safety of their operations. 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. Although we believe these costs will ultimately be recoverable through our rates to customers, the costs of complying with such increased regulation could have at least a short-term 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.

In our utility segment, 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. We attempt to manage these exposures and mitigate our risks through adherence to established risk limits and risk management procedures, including hedging activities that are in accordance with our policy guidelines. We use both financial and physical hedging mechanisms, including our recent gas reserve transaction in which we are acquiring long-term gas reserves through an investment with Encana Oil & Gas (USA). These risk limits and risk management procedures 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 which could adversely impact our financial condition, results of operations, and cash flows.

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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, thereby limiting our exposure to earnings volatility on a year-to-year basis. However, the hedge transactions we enter into for the utility are subject to a prudency review by the OPUC and WUTC, and, if deemed imprudent, those expenses may be disallowed, which could have an adverse effect on our financial condition and results of operations. In addition, 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. Although our valuations take into account the expected probability of default and the potential loss due to a default by our counterparties, an actual default by a particular counterparty could have a greater impact than we estimate. 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.

Changes in accounting standards. Changes in accounting standards may adversely impact our financial condition and results of operations.

Our business is currently subject to accounting standards issued by the Financial Accounting Standards Board. Changes in these standards could adversely impact our financial condition or results of operations. Recently, the SEC has been considering whether issuers in the United States should be required to prepare financial statements in accordance with International Financial Reporting Standards (IFRS) instead of the current generally accepted accounting principles (GAAP) in the United States. IFRS is a comprehensive set of accounting standards promulgated by the International Accounting Standards Board (IASB), which are currently in effect for most other countries in the world. If the SEC decides to adopt IFRS, we expect that U.S. companies would not be required to report under these new standards until 2015 or 2016 at the earliest. Unlike U.S. GAAP, IFRS does not currently provide an industry accounting standard for rate-regulated activities. As such, if IFRS were adopted in its current state, we may be precluded from applying certain regulatory accounting principles, including the recognition of certain regulatory assets and regulatory liabilities. The potential issues associated with rate-regulated accounting, along with other potential changes associated with the adoption of IFRS, may have a significant impact on our financial condition and results of operations. Also, the U.S. Financial Accounting Standards Board is considering several changes to U.S. GAAP, some of which may be significant, as part of a joint effort with the IASB to converge accounting standards over the next several years. If approved, adoption of these changes may adversely impact our financial condition and results of operations.

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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, imports and exports of natural gas, transportation constraints, availability of pipeline capacity, transportation capacity cost increases, federal and state energy and environmental regulation and legislation, the degree of market liquidity, supply disruption, natural disasters, wars 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 at the utility is generally passed through to our customers through an annual PGA rate adjustment. Recent years have seen a substantial decline in natural gas prices as new drilling technologies have been employed to produce abundant U.S. supplies of natural gas. If this trend in commodity prices were to reverse and thereby result in significant increases in the commodity price of natural gas, it would raise the cost of energy to our utility customers, potentially causing those customers to conserve or switch to alternate sources of energy. Significant price increases could also cause new home builders and commercial developers to select heating systems other than natural gas. Decreases in the volume of gas we sell could reduce our earnings in the absence of decoupled rate structures, and a decline in customers could slow growth in our future earnings.

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 several months or even a year 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. This could contribute to higher short-term debt levels, greater expense associated with collection efforts and increased bad debt expense.

In Oregon and Washington, our utility has PGA tariffs which provide for annual revisions in rates resulting from changes in the cost of purchased gas including the expected impact on bad debt expense. The Oregon PGA tariff provides an incentive to the Company to achieve lower gas costs such that a small percentage, set annually, of any cost savings (i.e. the difference between the estimated average PGA gas cost in rates and the actual average gas cost incurred) be recognized as current income or expense. Accordingly, higher average gas costs than those assumed in setting rates can adversely affect our operating cash flows, liquidity and results of operations. 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.

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. Continued weakness in the residential new construction and conversion markets, and continued decline in average use of natural gas by our residential and commercial customers, 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.

Higher natural gas prices have at times eroded, or in some cases eliminated, the competitive price advantage of natural gas over other energy sources. 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 or environmental impact of 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 substantially all of 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, as well as our ability to acquire supplies directly from new sources. Certain factors including the following may affect our ability to acquire and deliver natural gas to our current and future customers: suppliers' or other third parties' control over drilling of new wells and operating facilities to transport natural gas to our distribution system; competition for the acquisition of natural gas; priority allocations on transmission pipelines; impact of severe weather disruptions to natural gas supplies; failure of third parties to deliver gas for which we have contracted; the regulatory and pricing policies of federal, state and local government agencies; and the availability of Canadian reserves for export to the United States. If we are unable to obtain, or are limited in our ability to obtain, natural gas from our current suppliers or new sources, our financial results could be adversely impacted.

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 or a failure to renew our weather normalization mechanism 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, approximately 9 percent of our Oregon residential and commercial customers have opted out of the weather normalization mechanism, and 10 percent of our customers are located in Washington where we do not have a weather normalization mechanism. Furthermore, continuation of the weather normalization mechanism in Oregon after October 2012 is subject to regulatory approval. As a result, we may not be fully protected against warmer than average or colder than average weather, both of which may have an adverse effect on our financial condition, results of operations and cash flows.

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Customer conservation risk. Customers' conservation efforts or a failure to renew our conservation tariff 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, which can decrease our sales of natural gas and adversely affect our results of operations. In Oregon, we have a conservation tariff which is designed to recover lost margin due to declines in residential and commercial customers' consumption. The conservation tariff is scheduled to expire in October 2012. The failure of the OPUC to extend the conservation tariff in the future could adversely affect our financial condition, results of operations and cash flows. We do not have a conservation tariff in Washington, so our results of operations are negatively affected by increasing conservation efforts.

Business improvements 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, which provides an integrated suite of business application software; an automated dispatch system, which provides integrated planning, scheduling and dispatching of field resources; an automated meter reading system, which allows for electronic reading of customers meters; a customer information system, which allows us to calculate and bill customers for gas service including adjustments such as the weather normalization impact; 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. Although we have, when possible, developed alternative sources of technology and built redundancy into our computer networks and tools, there can be no assurance that these efforts to date would protect us against all potential issues or disaster occurrences related to the loss of any such technologies or their use.

Furthermore, our operations are subject to cyber-security risks related to breaches in technologies that are used in our natural gas distribution and storage operations and other business processes. Additionally, our utility is subject to breaches of security pertaining to sensitive customer, employee and vendor information maintained by the utility in the normal course of business. Although we have preventive and detective measures in place to reduce the risk of such security breaches, they could occur and result in a loss of confidential or proprietary data or security breaches of other technology business tools, 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.

Risks Related Primarily to Our Gas Storage Business

Long-term stabilization of gas price risk. Any significant stabilization of natural 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. However, the market for natural gas may not continue to experience volatility and seasonal price sensitivity in the future at the levels previously seen. 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 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 has been successfully completed to meet our contractual obligations and project specifications with respect to injection, withdrawal and gas specifications, the facility is new, has a limited operating history, and is not expected to reach full design capacity until the end of 2012. If we fail to achieve design capacity, 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 13,900 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.

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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 percent 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 11,300 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 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. In December 2011, NW Natural reached a settlement with Associated Electric & Gas Insurance Services Limited and dismissed that insurer from the litigation.

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

(A) 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:

| | 2011 | | 2010 | |
|---|---|---|---|---|
| Quarter Ended | High | Low | High | Low |
| March 31 | $48.72 | $43.92 | $47.54 | $41.05 |
| June 30 | 46.40 | 43.57 | 49.18 | 41.90 |
| September 30 | 46.77 | 39.63 | 49.00 | 42.63 |
| December 31 | 48.98 | 42.52 | 50.86 | 44.02 |

The closing quotations for our common stock on December 31, 2011 and 2010 were $47.93 and $46.47, respectively.

(B) As of December 31, 2011, there were 6,745 holders of record of our common stock.

(C) 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 | 2011 | 2010 |
|---|---|---|
| February 15 | $0.435 | $0.415 |
| May 15 | 0.435 | 0.415 |
| August 15 | 0.435 | 0.415 |
| November 15 | 0.445 | 0.435 |
| Total per share | $1.750 | $1.680 |

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.

(D) 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 2011:

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ISSUER PURCHASES OF EQUITY SECURITIES

| Period | (a) Total Number of Shares Purchased(1) | (b) Average Price Paid per Share | (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(2) | (d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(2) |
|---|---|---|---|---|
| Balance forward | | | 2,124,528 | $ 16,732,648 |
| 10/01/11 - 10/31/11 | - | $- | - | - |
| 11/01/11 - 11/30/11 | 3,262 | $47.00 | - | - |
| 12/01/11 - 12/31/11 | - | $- | - | - |
| Total | 3,262 | $47.00 | 2,124,528 | $ 16,732,648 |

(1) During the quarter ended December 31, 2011, 3,262 shares of our common stock were purchased on the open market to meet the requirements of our deferred compensation programs. During the quarter ended December 31, 2011, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a share repurchase program under which we purchase NWN common stock on the open market or through privately negotiated transactions. The program is currently authorized by the Board through May 31, 2012, with approval 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, 2011, 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, | | | | |
|---|---|---|---|---|---|
| Thousands, except per share amounts | 2011 | 2010 | 2009 | 2008 | 2007 |
| Net operating revenues | $369,433 | $367,581 | $376,887 | $356,215 | $369,042 |
| Net income | 63,898 | 72,667 | 75,122 | 69,525 | 74,497 |
| Earnings per share of common stock: | | | | | |
| Basic | 2.39 | 2.73 | 2.83 | 2.63 | 2.78 |
| Diluted | 2.39 | 2.73 | 2.83 | 2.61 | 2.76 |
| Dividends paid per share of common stock | 1.75 | 1.68 | 1.60 | 1.52 | 1.44 |
| Total assets - at end of period | 2,746,574 | 2,616,616 | 2,399,252 | 2,378,152 | 2,014,061 |
| Common stock equity | 714,488 | 693,101 | 660,105 | 628,373 | 594,751 |
| Long-term debt | 641,700 | 591,700 | 601,700 | 512,000 | 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) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated activities for the years ended December 31, 2011, 2010, and 2009. Unless otherwise indicated, references in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in this report.

The consolidated financial statements include the accounts of NW Natural and its direct and indirect wholly-owned subsidiaries which include: Gill Ranch Storage, LLC (Gill Ranch), NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), and NNG Financial Corporation (NNG Financial). These statements also include accounts related to an 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). These accounts 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 local gas distribution business (local distribution company), and the term "non-utility" is used to describe our regulated gas storage businesses (gas storage) as well as our other regulated and non-regulated investments and business activities (other). For a further discussion of our business segments, see Note 4.

In addition to presenting results of operations and earnings amounts in total, certain measures are expressed in cents per share. These amounts reflect factors that directly impact earnings. We believe this per share information is useful because it enables readers to better understand the impact of these factors on consolidated earnings. All references in this section to earnings per share are on the basis of diluted shares. We also present free cash flow as we believe this supplemental information enables the reader of the financial statements to better understand our cash generating ability and to benefit from seeing cash flow results from management's perspective in addition to the traditional GAAP presentation (see "Cash Flows – Financing Activities," below). We use such non-GAAP (i.e. non-generally accepted accounting principles) measures in analyzing our financial performance because we believe that they provide useful information to our investors and creditors in evaluating NW Natural's financial condition and results of operations.

### Executive Summary

Highlights of 2011 include:

- Consolidated earnings of $63.9 million and $2.39 per share in 2011, compared to $72.7 million and $2.73 in 2010;
- Net income from utility operations decreased $5.7 million, from $66.3 million in 2010 to $60.5 million in 2011;
- Net income from gas storage operations decreased $2.0 million, from $6.1 million in 2010 to $4.1 million in 2011;
- Net operating revenues (margin) increased 1 percent, from $367.6 million in 2010 to $369.4 million in 2011;
- Total operating expenses increased 7 percent, from $210.0 million in 2010 to $224.6 million in 2011;
- Cash flow from operations increased $107.0 million, from $126.5 million in 2010 to $233.5 million in 2011;
- Utility customer growth rate was 0.8 percent in 2011, compared to 0.9 percent in 2010; and
- Dividends paid increased 4 percent, from $1.68 per share in 2010 to $1.75 in 2011, reflecting the 56th consecutive year of dividend increases to shareholders.

Our primary businesses consist of regulated utility and gas storage operations.  Factors critical to the success of the utility include: maintaining a safe and reliable distribution system; acquiring an adequate supply of natural gas; providing distribution services at competitive prices; and being able to recover our operating and capital costs in the rates charged to customers in a reasonable and timely manner. Our utility business is regulated by two state commissions, the Public Utility Commission of Oregon (OPUC) and the Washington Utilities and Transportation Commission (WUTC).  Factors critical to the success of our gas storage business include: developing and operating storage capacity at competitive market prices; retaining customers and successfully marketing available storage capacity to new customers; planning for the replacement of capacity that is expected to be recalled by the utility to serve growing demands of its core customers; charging adequate rates to recover investment and operating costs; and being able to obtain financing to fund expansions and working capital requirements.  Our gas storage businesses are, in part, regulated by the California Public Utilities Commission (CPUC), the Federal Energy Regulatory Commission (FERC) and the OPUC.

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2012 Outlook

In 2012, we will be focused on strengthening our core businesses, enhancing our strategic position, advancing key business projects, and leveraging our organizational resources.

Strengthen Core Businesses. Our core businesses are local gas distribution (utility) and gas storage. In the utility, we will continue our efforts to develop, integrate, consolidate and streamline our operations using new technologies, which are expected to include a workforce scheduling system, a procurement system, and an automated dispatching system. In our storage business, we will focus on maximizing our storage capacity and optimizing our revenue opportunities. We believe that investing in operating efficiencies and in marketing opportunities for our core businesses positions us well for growth now and into the future as the economy recovers.

Enhance Strategic Position. We believe our core businesses are positioned strategically and competitively. The decline in gas prices and the abundance of shale gas supplies creates opportunities for both core businesses. Specifically, it creates opportunities for us to expand our market share in the utility by leveraging our natural gas' competitive price advantage. Moreover, our gas storage facilities strategically position us to quickly respond to market demand with storage capacity when gas prices increase or become more volatile. Together, our businesses competitively position us to meet market demands when the economy recovers.

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 acquiring long-term gas reserves on behalf of our utility customers, pursuing future storage opportunities at Mist, and improving our operations at Gill Ranch. We also continue to pursue regional solutions for reliable and safe energy needs through our investment in natural gas infrastructure, such as the Palomar pipeline.

Leverage Resources. Our employees are our most valued resource. To support and leverage this valuable resource, we will continue to invest in new technologies and improve our facilities. We believe this will allow us to maintain a positive and safe work environment, to provide on-going training and workforce development, and also to gain greater operational efficiency.

Issues, Challenges and Performance Measures

Economic weakness. Weakness in local, national and global economies continues to impact utility customer growth, business demand for natural gas and market prices for gas storage. Our utility's customer growth rate remained relatively flat for the third year in a row at 0.8 percent, compared to 0.9 percent in 2010 and 0.8 percent in 2009. The local economy is beginning to show signs of a slow recovery as unemployment rates in Oregon and southwest Washington dropped from approximately 10 percent in 2010 to about 9 percent at the end of 2011, and industrial demand for natural gas increased in 2011 by 1 percent over 2010. We believe our utility is well positioned to add customers as the economy recovers because of low and stable natural gas prices, our relatively low market penetration, our ongoing focus on converting homes and businesses to natural gas, and the potential for environmental initiatives that could favor natural gas use in our region.

Managing gas prices and supplies. Our gas acquisition strategy is regularly updated to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices so that we can effectively manage costs, reduce price volatility and maintain a competitive advantage. With recent developments in drilling technologies and substantial access to supplies from shale gas formations around the U.S. and in Canada, the supply outlook for North American natural gas is strong, which is contributing to lower and more stable gas prices.

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The Purchased Gas Adjustment (PGA) mechanisms in Oregon and Washington, along with our gas price hedging strategies, including gas reserves and storage supplies, enable us to reduce earnings exposure for the company and secure lower gas costs for our customers. These lower gas prices, coupled with our focus on customer service and cost-effective energy efficiency programs, can help strengthen natural gas' competitive advantage over other energy sources in key markets.

We typically hedge gas prices on approximately 75 percent of our anticipated year-round sales volumes based on normal weather. For the 2011-12 gas year (November 1, 2011 – October 31, 2012), we entered the gas year hedged at a level of approximately 75 percent of our forecasted sales volumes, including 51 percent financially hedged and 24 percent physically hedged with a combination of gas inventories in storage, local production from the Mist area, and production of gas reserves from our investment with Encana Oil & Gas (USA) Inc. (Encana). The production of gas reserves is related to a new investment we made beginning in 2011 to hold working interests in leases related to both currently producing and new wells in Encana's Jonah gas field located in Rock Springs, Wyoming. For further discussion of gas reserves, see Investments in Gas Reserves under Strategic Opportunities below and Gas Reserves under Rate Mechanisms below.

In addition to the amount of gas hedged for the current gas contract year, we are also hedged at approximately 32 percent for the 2012-13 gas year and between 9 and 13 percent hedged 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 levels may increase or decrease based on storage expansion or storage recall by the utility. As for gas reserves, these levels are estimates of production, which are subject to change based on possible unforeseen events that include the impact from speed of drilling and the volume of production.

Although stable gas prices provide opportunities to manage costs for our utility customers, they also present challenges for our gas storage business. Stable natural gas prices may reduce the pricing for storage services. We are focused on improving the results from our gas storage businesses.

Environmental costs. We accrue all material environmental loss contingencies related to our properties that require environmental investigation or remediation. Due to numerous uncertainties surrounding the preliminary nature of investigations or the developing nature of remediation requirements, actual costs could vary significantly from our loss estimates. As a regulated utility, we are allowed to defer certain costs pursuant to regulatory decisions. We currently have regulatory approval to defer certain environmental costs, and to seek recovery of these amounts in future rates to customers. However, we are expected to pursue recovery from insurance policies and only seek recovery from customers for amounts not covered by insurance. Ultimate recovery of environmental costs, either from regulated utility rates or from insurance, will depend on our ability to effectively manage costs and demonstrate that costs were prudently incurred. 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 our businesses are likely to be impacted by future carbon constraints, and 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 cause 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. Under EPA's greenhouse gas reporting rules adopted in 2009, we report system throughput to the EPA on an annual basis. The first report under these provisions was due to EPA in September 2011. EPA also issued additional greenhouse gas reporting regulations in 2010, which required mandatory reporting of unintended greenhouse gas releases from petroleum and natural gas facilities. The first report is due under these rules in September 2012. 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: further improving our utility gas distribution system; enhancing utility services and operations; optimizing and growing our non-utility gas storage businesses; investing in natural gas infrastructure projects when necessary to support the energy needs of our region; and maintaining a leadership role within the gas utility industry by addressing long-term energy policies and pursuing business opportunities that support new clean energy technologies. We intend to measure our performance and monitor progress on relevant metrics including, but not limited to: earnings per share growth; total shareholder return; return on invested capital; utility return on equity; utility customer satisfaction ratings; utility margin; utility capital and operations and maintenance expense per customer; and earnings before interest, taxes, depreciation and amortization and (EBITDA).

Strategic Opportunities

Business Process Improvements. We continue to evaluate, develop and implement business strategies to improve operational efficiencies and respond to economic and competitive challenges. Over the last few years, our efforts have been to develop, integrate, consolidate and streamline operations, while supporting our employees with training and new technology tools.

From 2006 through 2010, we reduced staffing levels in response to work load declines related to the low customer growth environment and efficiency improvements, resulting in a reduction of full-time, utility positions from over 1,300 in early 2006 to about 1,050 at the end of 2011. Technology investments, workforce reductions and other initiatives have contributed to a significant increase in productivity. The number of utility customers served per operating employee increased by 32 percent, from 738 at the end of 2005 to 976 at the end of 2011. These efforts are expected to contribute to long-term operational efficiencies and lower operating and capital costs throughout NW Natural. However, we continue to look for new ways to improve our business as service demands and system safety requirements increase and we remain committed to increasing shareholder value.

Gas Storage Development. We own and operate two underground gas storage facilities—the Mist facility in Oregon and the Gill Ranch facility in Fresno, California. Our wholly-owned subsidiary, Gill Ranch, holds a 75 percent undivided ownership interest in the Gill Ranch facility, with Pacific Gas and Electric Company (PG&E) owning the other 25 percent interest. The initial development of Gill Ranch was designed to provide us with 15 Bcf of gas storage capacity by the end of 2012, with pipeline capacity on 27 miles of gas transmission pipeline connecting the Gill Ranch facility to an interconnect on PG&E's transmission system. See Note 4.

Due to an abundant supply of natural gas and lower, more stable prices in North America, current storage values are expected to remain low in the near term, which will likely affect the prices at which Gill Ranch is able to contract. Gas prices have hit a 10-year low and this has resulted in certain natural gas producers reducing their levels of exploration and production. At the same time, we expect these lower gas prices to increase demand for natural gas as the pricing provides a competitive advantage over alternative fuel sources including potential demand for exporting natural gas. Combined, these forces may ultimately result in upward pressure on gas prices and return some price volatility to natural gas markets.

Our storage facilities help position us to capitalize on rising demand, increasing gas prices or greater market volatility because storage operations benefit from seasonal swings in commodity pricing and market volatility. Additionally, if market demand increases and we are able to obtain financing and regulatory permits, we have the ability to expand the Gill Ranch facility beyond its current capacity without further expansion of our gas transmission pipeline. We estimate that the current Gill Ranch storage facility could support an aggregate storage capacity of around 40 Bcf with certain infrastructure modifications, of which we would have the rights to 50 percent of the total.

The Pacific Northwest storage markets also are impacted by lower gas prices and lack of gas price volatility, although less than California markets primarily because of fewer regional competitors. Nevertheless, we continue to plan for expansion of our gas storage facilities at Mist in anticipation of increased natural gas demand for electric generation in the Pacific Northwest. Currently we do not have a set timeline for development, but we believe the earliest timeframe for completing the next Mist expansion is 2016. In the meantime, we expect to continue working on preliminary design and project scope, which will most likely include the development of storage wells, a second compression station and additional pipeline gathering facilities that would enable future storage expansions.

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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. 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 percent by our NWN Energy subsidiary and 50 percent by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. The Palomar pipeline was originally proposed with an east and a west segment, but Palomar currently plans to design and develop an east-only pipeline to serve our utility customers as well as growing natural gas markets in Oregon and other parts of the Pacific Northwest. In the second quarter of 2011, Palomar determined it should discontinue efforts to develop the west segment of the pipeline after the supporting shipper declared bankruptcy. As a result, we recorded a charge of $0.3 million for our portion of the unrecovered costs related to the west segment.

Regarding the proposed east pipeline segment, Palomar negotiated a non-binding memorandum of understanding with The Williams Companies' Northwest Pipeline (Northwest Pipeline), which contemplates Northwest Pipeline becoming a part owner in the Palomar project. This joint agreement would consolidate the region's efforts to develop a cross-Cascades pipeline around the use of the Palomar route. Northwest Pipeline owns and operates the single bi-directional pipeline that connects to NW Natural's utility distribution system.

The proposed east segment pipeline would be regulated by FERC. In March 2011, Palomar withdrew its original application with FERC for the proposed pipeline in Oregon, but at the same time informed FERC that it intends to file a new application with a modified scope that excludes the west segment, after it has conducted a new open season to obtain commercial support for the east segment. The timing for when the Palomar pipeline is expected to be built and placed into service will be dependent upon regulatory permits and commercial support from shippers.

In the fourth quarter of 2011, we recorded a charge of $1.0 million related to the investment in the east segment of the project. This charge was for costs that were determined to be less than probable of recovery in a FERC rate making proceeding because they might be deemed outdated when we refile with FERC. Our investment balance in Palomar at December 31, 2011 after the charge was $13.5 million, which represents our share of Palomar's development costs related to the east segment. See Note 12 and see also "Financial Condition—Cash Flows—Investing Activities," below for further discussion on the status of Palomar.

Gas Reserves. In addition to hedging gas prices with financial derivative contracts, we recently signed an agreement with Encana to acquire physical gas supplies to meet a portion of our Oregon utility customers' requirements over 30 years. During the first 10 years, we forecast the volumes of gas received under the Encana agreement to provide approximately 8 to 10 percent of the average annual requirements of our utility customers. Under the agreement, we expect to invest approximately $45 million to $55 million per year for five years, with our total investment expected to be about $250 million. We pay a fixed portion of drilling costs per well. Encana assigns to us working interests in leases to certain sections of the Jonah gas field, located near Rock Springs, Wyoming. These sections include both future and currently producing wells. The working interests will entitle us to receive a portion of the gas produced in these sections. Operation of the wells will be governed by a joint operating agreement under which Encana will be the operator, and we will pay our proportionate share of operating costs. See Results of Operations—Regulatory Matters—Rate Mechanisms—Gas Reserves below and 2012 Outlook—Issues, Challenges and Performance Measures—Managing gas prices and supplies above.

Consolidated Earnings and Dividends

Consolidated net income was $63.9 million, or $2.39 per share, for the year ended December 31, 2011, compared to $72.7 million, or $2.73 per share, and $75.1 million, or $2.83 per share, for the years ended December 31, 2010 and 2009, respectively. Consolidated earnings decreased in fiscal year 2011 primarily due to the loss of income from the repeal of Oregon's legislative rule on utility income tax true up, a refund of utility property taxes in 2010, and a lower earnings contribution from our gas storage segment, which includes the first full year of operations for subsidiaries Gill Ranch and NWN Gas Storage. These decreases were partially offset by increased margin results from sales and transportation revenues reported by our utility gas distribution business. Consolidated returns on average stockholders' equity for these three years were 9.1 percent, 10.7 percent and 11.7 percent, respectively. See "Application of Critical Accounting Policies and Estimates—Regulatory Accounting" for a discussion of the legislative rule.