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.

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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".

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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 Storage[1]	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.

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.

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.

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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.

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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.

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.

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.

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.

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.

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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.

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2011 compared to 2010:

The most significant factors contributing to the $8.8 million decrease in consolidated net income were:

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

Partially offsetting the above factors were:

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

2010 compared to 2009:

The most significant factors contributing to the $2.4 million decrease in consolidated net income were:

- a $13.5 million decrease in utility margin from the regulatory gas cost incentive sharing mechanism, which reflects gains of $15.1 million in 2009 compared to gains of $1.6 million in 2010;
- a $2.9 million net loss from Gill Ranch, and a $0.6 million net loss from NWN Gas Storage, primarily reflecting higher operating expenses related to start-up activities;
- a $2.8 million increase in income tax expense primarily reflecting higher taxable income from the utility, including higher amortization of regulatory tax balances related to pre-1981 assets which are offset by increased revenues collected in utility margin; and
- a $1.9 million increase in interest expense primarily reflecting the full year effect of lower-rate short-term debt refinanced with higher-rate long-term debt during 2009 and higher balances of total debt outstanding.

Partially offsetting the above factors were:

- a $14.3 million decrease in utility operating expenses primarily due to lower property tax, payroll, bad debt, and employee benefit costs;
- a $5.0 million increase in utility margin from residential and commercial customers, after adjustments for weather and decoupling mechanisms, primarily due to colder weather benefits in the second quarter of 2010 when weather normalization was not in effect, customer growth and the rate recovery of higher income tax expenses related to an increase in Oregon tax rates and the accelerated amortization of regulatory tax assets; and
- a $3.4 million increase in other income primarily due to higher carrying costs from utility deferred regulatory account balances and interest income from a utility property tax refund, partially offset by a decrease in non-utility gains from company-owned life insurance.

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Dividends paid on our common stock were $1.75 per share in 2011, compared to $1.68 per share in 2010 and $1.60 per share in 2009. The Board of Directors declared a quarterly dividend on our common stock of 44.5 cents per share, payable on February 15, 2012, increasing the indicated annual dividend rate to $1.78 per share.

Application of Critical Accounting Policies and Estimates

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

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

Management has discussed its current estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Within the context of our critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 2.

Regulatory Accounting

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

The conditions we must satisfy to adopt the accounting policies and practices of regulatory accounting, which are applicable to regulated companies, include:

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

Because our utility satisfies all three conditions, we continue to apply regulatory accounting to our utility operations. Future accounting changes, regulatory changes or changes in the competitive environment could require us to discontinue the application of regulatory accounting for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers. Based on current accounting, regulatory and competitive conditions, we believe that it is reasonable to expect continued application of regulatory accounting for our utility activities, and that all of our regulatory assets and liabilities at December 31, 2011 and 2010 are recoverable or refundable through future customer rates. The net balance in regulatory asset and liability accounts as of December 31, 2011 and 2010 was $156.6 million and $125.8 million, of assets, respectively. See "Industry Regulation" in Note 2.

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Revenue Recognition

Utility and non-utility revenues, which are derived primarily from the sale, transportation and storage of natural gas, are recognized upon the delivery of gas commodity or services rendered to customers. Revenues are accrued for gas delivered and services rendered to customers, but not yet billed, based on estimates from the last meter reading date to month end (accrued unbilled revenues). Accrued unbilled revenues are primarily based on a percentage estimate of amounts unbilled each month, which is dependent upon a number of factors, some of which require management's judgment. These factors include total gas receipts and deliveries, customer meter reading dates, customer usage patterns and weather. Accrued unbilled revenue estimates are reversed the following month when actual billings occur. Estimated unbilled revenues at December 31, 2011 and 2010 were $61.9 million and $64.8 million, respectively. The decrease in accrued unbilled revenues at year-end 2011 was primarily due to lower volumes in December 2011, reflecting warmer weather late in the month, and lower customer billing rates. If the estimated percentage of unbilled volume at December 31, 2011 was adjusted up or down by 1 percent, then unbilled revenues, net operating revenues and net income would have increased or decreased by an estimated $1.9 million, $0.5 million and $0.6 million, respectively.

From 2007 through 2010, utility revenues included the recognition of a regulatory adjustment for income taxes paid (commonly referred to as SB 408). Under SB 408, we were required to automatically implement a rate refund, or a rate surcharge, to utility customers on an annual basis. The refund or surcharge amount was based on estimated differences between income taxes paid and income taxes collected in customer rates. We recorded the refund, or surcharge, each quarter based on the annual amount to be recognized. On May 24, 2011 the Oregon Governor signed Senate Bill 967 (SB 967), which repealed SB 408. The new law required utilities in Oregon to reverse amounts accrued for the 2010 and 2011 tax years, which resulted in us recording a one-time pre-tax charge to earnings in the second quarter of 2011 in the amount of $7.4 million ($4.4 million after-tax or 17 cents per share). For further discussion, see "Results of Operations—Business Segments—Utility Operations—Regulatory Adjustment for Income Taxes Paid," below.

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

Accounting for Derivative Instruments and Hedging Activities

Our gas acquisition and hedging policies set forth guidelines for using financial derivative instruments to support prudent risk management strategies. These policies specifically prohibit the use of derivatives for trading or speculative purposes. The accounting rules for determining whether a contract meets the definition of a derivative instrument or qualifies for hedge accounting treatment are complex. The contracts that meet the definition of a derivative instrument are recorded on our balance sheet at fair value. If certain regulatory conditions are met, then the derivative instrument fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to regulatory accounting (see Note 2, "Industry Regulation"), and no unrealized gain or loss is recognized in current income. The gain or loss from the fair value of a derivative instrument subject to regulatory deferral is included in the recovery from, or refund to, utility customers in future periods (see "Regulatory Accounting," above). If a derivative contract is not subject to regulatory deferral, then the accounting treatment for unrealized gains and losses is recorded in accordance with accounting standards for derivatives and hedging (see Note 2, "Derivatives" and "Industry Regulation") which is either in current income or in accumulated other comprehensive income under common stock equity on the balance sheet. Our derivative contracts outstanding at December 31, 2011 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. Our estimate of fair value may change significantly from period-to-period depending on market conditions and prices. These changes may have an impact on our results of operations, but the impact would largely be mitigated due to the majority of our derivatives activities being subject to regulatory deferral treatment. For estimated fair value of unrealized gains and losses at December 31, 2011 and 2010, see Note 13.

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Commodity-based derivative contracts entered into by the utility after our annual PGA filing for the current gas contract period are subject to a regulatory incentive sharing mechanism in Oregon (see "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," below). The portion not deferred to a regulatory account pursuant to that sharing agreement is recognized either in current income for contracts not qualifying for hedge accounting or in accumulated other comprehensive income for contracts qualifying for hedge accounting.

Derivative contracts not qualifying for regulatory deferral are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2011, all of our derivatives were effective economic hedges and either qualified or were expected to qualify for regulatory deferral or hedge accounting treatment. We use the hypothetical derivative method under accounting standards for derivatives and hedging to determine the hedge effectiveness for our interest rate swaps and the dollar offset method for other derivative contracts under accounting standards for derivatives and hedging. The effectiveness test applied to financial derivatives is dependent on the type of derivative and its use.

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

Thousands	2011	2010	2009
Net gain (loss) on commodity-price swaps - utility	$(53,834)	$(60,362)	$(172,089)
Net gain (loss) on commodity-price options - utility	(2,695)	(610)	(5,809)
Net gain (loss) on interest rate swap - utility	-	-	(10,096)
Subtotal - utility	(56,529)	(60,972)	(187,994)
Net gain (loss) on foreign currency forward purchases - utility	(52)	72	88
Total net gain (loss) realized	$(56,581)	$(60,900)	$(187,906)

Realized gains (losses) from commodity hedges and foreign currency forward purchase contracts are recorded as reductions (increases) to the cost of gas and are included in the calculation of annual PGA rate changes. Realized gains (losses) from interest rate hedges are recorded as reductions (increases) to interest charges over the term of the underlying debt issuances. Unrealized gains and losses from commodity hedges, foreign currency hedges and interest rate hedges, which reflect quarterly mark-to-market valuations, are generally not recognized in current income or accumulated other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, and are offset by a corresponding balance in derivative instruments (see Note 13).

Accounting for Pensions and Postretirement Benefits

We maintain two qualified non-contributory defined benefit pension plans covering a majority of our regular employees with more than one year of service, several non-qualified supplemental pension plans for eligible executive officers and certain key employees, and other postretirement employee benefit plans. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. Only the two qualified defined benefit pension plans and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund the respective retirement benefits. Effective January 1, 2007 and 2010, the qualified defined benefit retirement plans for non-union employees and for union employees, respectively, were closed to new participants. These plans were not available to employees at any of our subsidiary companies. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and our subsidiary employees, are provided an enhanced Retirement K

Savings Plan benefit. Also, effective January 1, 2007 the postretirement Welfare Benefit Plan for Non-Bargaining Unit Employees was closed to new participants after December 31, 2006.

Net periodic pension and postretirement benefit costs (retirement benefit costs) and projected benefit obligations (benefit obligations) are determined in accordance with accounting standards for compensation and retirement benefits using a number of key assumptions including discount rates, rate of compensation increases, retirement ages, mortality rates and an expected long-term return on plan assets (see Note 9). These key assumptions have a significant impact on the pension amounts recorded and disclosed. Retirement benefit costs consist of service costs, interest costs, the amortization of actuarial gains, losses and prior service costs, the expected returns on plan assets and, in part, on a market-related valuation of assets, if applicable. The market-related asset valuation reflects differences between expected returns and actual investment returns, which we recognize over a three-year period or less from the year in which they occur, thereby reducing year-to-year volatility in retirement benefit costs.

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Accounting standards also require balance sheet recognition of the overfunded or underfunded status of pension and postretirement benefit plans in accumulated other comprehensive income (AOCI), net of tax, based on the fair value of plan assets compared to the actuarial value of future benefit obligations. However, the retirement benefit costs relating to our qualified defined benefit pension and postretirement benefit plans are generally recovered in utility rates which are set based on accounting standards for pensions and postretirement benefits, and as such we received approval from the OPUC pursuant to regulatory accounting to recognize the overfunded or underfunded status as a regulatory asset or regulatory liability based on expected rate recovery, rather than including it as AOCI under common equity (see “Regulatory Accounting”, above, and Note 2, “Industry Regulation”).

The retirement benefit cost for pensions consists of service costs, interest costs, the expected returns on plan assets, and the amortization of actuarial gains and losses. Effective January 1, 2011, we began deferring a portion of our pension expense to a regulatory account on the balance sheet pursuant to OPUC approval of pension expenses above or below the amount set in rates. In 2011, the cumulative amount deferred for future pension cost recovery was $6.0 million. The regulatory asset account earns a carrying cost at the authorized cost of capital rate set by the OPUC.

A number of factors are considered in developing pension and postretirement assumptions, including evaluations of relevant discount rates, an evaluation of expected long-term investment returns based on asset classes and target asset allocations, expected changes in salaries and wages, analyses of past retirement plan experience and current market conditions and input from actuaries and other consultants. For the December 31, 2011 measurement date, we reviewed and updated:

- our weighted-average discount rate assumptions for pensions and other postretirement benefits, which went from 5.49 percent to 4.51 percent and from 5.16 percent to 4.33 percent, respectively. The new rate assumptions were determined for each plan based on a matching of benchmark interest rates to the estimated cash flows, which reflects the timing and amount of future benefit payments. Benchmark interest rates are drawn from the Citigroup Above Median Curve, which consists of high quality bonds rated AA- or higher by Standard & Poor’s (S&P) or Aa3 or higher by Moody’s Investors Service (Moody’s);
- our expected annual rate of future compensation increases, which remained unchanged at a range of 3.25 to 5.0 percent;
- our expected long-term return on qualified defined benefit plan assets, which was reduced to 8.00 percent from 8.25 percent; and
    - other key assumptions, which were based on actual experience and actuarial recommendations.

At December 31, 2011, our net pension liability (benefit obligations less market value of plan assets) for the two qualified defined benefit plans increased $51.5 million compared to 2010. The increase in our net pension liability is primarily due to the $48.4 million increase in our pension obligation. The liability for non-qualified plans increased $3.3 million and the liability for other postretirement benefits increased $2.4 million in 2011.

We determine the expected long-term rate of return on plan assets by averaging the expected earnings for the target asset portfolio. In developing our expected return, we evaluate an analysis of historical actual performance and long-term return projections, which gives consideration to the current asset mix and our target asset allocation. As of December 31, 2011, the actual annualized returns on plan assets, net of management fees, for the past one-year, five-years, 10-years and since inception were 2.4 percent, 0.2 percent, 4.8 percent and 9.9 percent, respectively.

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

Thousands, except percent	Change in Assumption	Impact on 2011 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2011
Discount rate:	(0.25 %)		
Qualified defined benefit plans		$ 1,162	$ 11,796
Non-qualified plans		8	53
Other postretirement benefits		54	754
Expected long-term return on plan assets:	(0.25 %)		
Qualified defined benefit plans		580	N/A

Accounting for Income Taxes

We account for income taxes in accordance with accounting standards that require the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amount and tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. At December 31, 2011 and 2010, our net long-term deferred tax liability totaled $413.2 million and $373.4 million, respectively. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our tax returns. For state income tax and local income taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is “more likely than not” that our deferred tax assets will not be realized. At December 31, 2011, we did not have a valuation allowance due to our expectation that all of these assets and liabilities will be realized.

These accounting standards also require the recognition of deferred income tax assets and liabilities for temporary differences where regulators require us to flow through deferred income tax benefits or expenses in the ratemaking process of the regulated utility (regulatory tax assets and liabilities). This is consistent with the ratemaking policies of the OPUC and WUTC. Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from, or refunded to, customers in future rates. At December 31, 2011 and 2010, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $68.5 million and $72.3 million, respectively, and recorded an offsetting deferred tax liability. We received authorization from the OPUC and WUTC in 2009 to accelerate the recovery of these pre-1981 regulatory assets through future utility rates. See Notes 2 and 10.

Uncertain tax positions are accounted for in accordance with accounting standards that require management’s assessment of the expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, we would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company’s consolidated balance sheet. As of December 31, 2011, we had no uncertain tax positions.

The IRS completed its examination of the 2006 through 2008 tax years in 2011. The examination resulted in payments of $1.5 million of tax and $0.2 million of interest. The Oregon Department of Revenue (ODOR) completed its field examination of our 2006 through 2009 consolidated Oregon income tax returns and issued preliminary assessments. If sustained by the ODOR, these assessments would result in an additional state tax liability of approximately $0.8 million, including interest and penalties. The Company is engaged in discussions with ODOR to resolve these issues; however, uncertainty exists with respect to the outcome of the audit as a result of information not yet fully considered by the ODOR. Resolution is expected to be reached within the next 12 months, and we have determined that it is more-likely-than-not that we will prevail on these issues. As such, no amounts have been recorded in our financial statements as of December 31, 2011 related to this matter.

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

Accounting for Contingencies

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

With respect to environmental liabilities and related costs, we develop estimates based on a review of information available from numerous sources, including completed studies and site specific negotiations. Using sampling data, feasibility studies, existing technology and enacted laws and regulations, we estimate that the total future expenditures for environmental investigation, monitoring and remediation are $72.7 million as of December 31, 2011. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, then it is our policy to accrue at the lower end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated.

We will continue to seek recovery of such costs through insurance and through customer rates, and we believe recovery of these costs is probable. If it is determined that both the insurance recovery and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made. See Note 15.

Results of Operations

Regulatory Matters

Regulation and Rates

Utility. We are subject to regulation with respect to, among other matters, rates and systems of accounts set by the OPUC, WUTC, and FERC. The OPUC and WUTC also regulate our issuance of securities by the utility. In 2011, approximately 90 percent of our utility gas volumes and revenues were derived from Oregon customers and approximately 10 percent from Washington customers. Future earnings and cash flows from utility operations will be determined by the Oregon and Washington economies in general, by the pace of growth in the residential and commercial markets in particular, and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, including operating and maintenance expenses and investment costs made in utility plant and other regulatory assets.

Gas Storage. Our gas storage business is subject to regulation with respect to, among other matters, issuance of securities and systems of accounts set by the OPUC, FERC, and the CPUC. The CPUC regulates Gill Ranch under a market based rates model which allows for the price for storage services to be set by market conditions. The OPUC and FERC regulate intrastate and interstate storage services, respectively, under a maximum cost of service model which allows for storage prices to be set at or below the cost of service as set in the last approved regulatory filing for each agency. In 2011, approximately 65 percent of our storage revenues were derived from FERC and Oregon approved rates to customers and approximately 35 percent from California approved rates to customers.

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General Rate Cases

Oregon. On December 30, 2011, we filed an application for a general rate increase at the OPUC. In the filing, we have requested an increase in authorized annual Oregon jurisdictional revenues of $43.7 million, equivalent to a rate increase of 6.2 percent. The amount and percent of this rate increase includes an estimated $15.1 million that represents the cumulative effect of declining use per customer. This cost is already included in customers' current rates through the operation of the Company's conservation tariff, which has been in place since 2003. The increase also includes costs related to pension contributions and additional utility services. The filing also requests an authorized overall rate of return on capital of 8.28 percent, with a return on common stock equity (ROE) of 10.3 percent and a capital structure of 50 percent common equity. In addition, we have requested the establishment of rate recovery mechanisms for deferred costs related to our environmental liabilities. The filing also requests rate redesign for residential customers with a higher fixed fee, which would effectively combine and incorporate the effects of the weather normalization and decoupling tariffs in the new fixed fee amount. The new rates are requested to be effective by November 1, 2012. We are unable to predict the outcome of this rate proceeding.

Our most recent general rate case in Oregon was effective September 2003. The OPUC authorized rates to customers based on an ROE of 10.2 percent. In 2007, in connection with the renewal of our conservation tariff and weather normalization rate mechanism, the OPUC approved a stipulation that restricted us from filing a general rate case in Oregon prior to September 2011. However, in 2011 the OPUC approved our gas reserve acquisition (see "Rate Mechanisms—Gas Reserves" below) with a condition that we file a general rate case by the end of 2011. These agreements did not impact our requirement to file annual rate adjustments to reflect changes in gas purchase costs under the PGA mechanism or our ability to collect or refund prior year's gas cost deferrals. See "Rate Mechanisms—Purchased Gas Adjustment," below.

Washington. Our most recent general rate case in Washington was in 2008, and in it the WUTC authorized rates to customers based on an ROE of 10.1 percent and an overall rate of return of 8.4 percent. These customer rates went into effect on January 1, 2009, with annual revenue requirements increased by $2.7 million or 3 percent.

FERC Jurisdiction. We are required under our Mist interstate storage certificate authority and rate approval orders to file every five years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for our interstate storage services. Our most recent filing of a cost and revenue study was in April 2008. As a result of that proceeding, the current maximum cost-based rates for our interstate gas storage services were approved by FERC, with maximum rates unchanged from prior levels approved by FERC in 2005. In addition, we made a filing in December 2008 to obtain FERC approval to revise the depreciation rates associated with Mist assets used to derive the cost-based interstate storage rates. These new depreciation rates were designed to match the depreciation rates for the same type of assets approved under state regulation. We did not make any changes to the previously approved maximum rates, and FERC approved the depreciation rate filing in May 2009. We are required to make our next cost and revenue study filing at FERC on or before December 11, 2013.

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

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including contract gas purchase prices, gas prices hedged with financial derivatives or physical gas reserves, gas inventory prices, interstate pipeline demand costs, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year.

In October 2011, the OPUC and WUTC approved PGA rate changes effective November 1, 2011. The effect of these rate changes was to decrease the average monthly bills of Oregon and Washington residential customers by about 2 percent. This was our third consecutive year of PGA rate decreases, and cumulatively our average utility residential customer bills declined 20 percent in Oregon and 26 percent in Washington since 2008.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80 percent or 90 percent deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20 percent or 10 percent of the difference between actual and estimated gas costs, respectively. In addition to the gas cost incentive sharing mechanism, we are subject to an annual earnings test to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33 percent of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80 percent deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90 percent deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90 percent deferral option for the 2009-10, the 2010-2011 and the 2011-2012 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2009 and 2010, the ROE threshold after adjustment for long-term interest rates was 11.5 percent and 11.02 percent, respectively. No amounts were required to be refunded to customers as a result of the 2009 utility earnings test, while we are refunding $0.2 million to customers in the current PGA for the 2010 utility earnings test. For 2011, we accrued an estimated $1.5 million for potential refund to customers in the next PGA.

There has been no change to the Washington PGA mechanism under which we defer 100 percent of the higher or lower actual gas costs, with those cost differences passed on to customers through an adjustment to future rates.

Gas Reserves. In April, 2011 the OPUC approved the Encana gas reserve transaction for utility customers and determined that the Company's costs under the agreement will be recovered, plus a rate base return on our investment, on an ongoing basis through our annual PGA mechanism, including the regulatory deferral and incentive sharing process for the commodity cost of gas. Annually, a forecast will be established for the amounts related to costs and volumes expected, and any variances between forecasted and actual results will be subject to our PGA incentive sharing in Oregon, up to a maximum variance of $10 million of which 10 percent (or $1 million maximum) would be recognized in current income. Variances in excess of $10 million, both negative and positive, will be deferred and passed through to customers in future rates at 100 percent.

Conservation Tariff. In October 2002, the OPUC authorized the implementation of a "conservation tariff" to adjust utility margin for changes in consumption patterns due to residential and commercial customers' conservation efforts. The conservation tariff is a decoupling mechanism that is intended to break the link between utility earnings and the quantity of gas consumed by customers, removing any financial incentive by the utility to discourage customers' efforts to conserve energy. In Washington, customer use is not covered by a conservation or decoupling tariff, and as such our utility earnings are affected by increases and decreases in usage based on customers' conservation efforts. Washington customers account for about 10 percent of our utility volumes and revenues.

The Oregon conservation tariff includes two components: (1) an annual price elasticity adjustment, which adjusts rates for increases or decreases from expected customer volumes due to changes in commodity costs or changes in our general rates; and (2) a monthly conservation adjustment, which adjusts margin revenues to account for the difference between actual and expected customer volumes (also referred to as the decoupling adjustment). The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the next annual PGA filing. Baseline consumption was determined by customer consumption data used in the 2003 Oregon general rate case and is adjusted annually for customer growth and the effect of the price elasticity adjustment discussed above. From 2003 to 2011, we have experienced approximately 14 percent decline in average use per residential customer and approximately 8 percent decline in average use per commercial customer. As a result of these declines, customers have paid surcharges related to a decoupling adjustment in seven of the past nine heating seasons. See "Business Segments - Utility Operations," below.

In 2005, an independent study was commissioned to measure the effectiveness of Oregon's conservation tariff mechanism. The results of this study recommended continuation of the tariff with minor modifications. The tariff modifications were approved by the OPUC, and the mechanism was extended through October 2012.

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Weather Normalization Tariff. In Oregon, we have an approved weather normalization mechanism applied to residential and commercial customer bills. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to bills between December 1 and May 15 of each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers (see "Business Segments - Utility Operations," below). The weather normalization mechanism for Oregon utility operations is approved through October 2012. Customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of December 31, 2011, 9 percent had opted out. We do not have a weather normalization mechanism approved for Washington customers, which account for about 10 percent of our utility volumes and revenues.

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

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

The OPUC has approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program, SIP, and the related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). We record the costs related to the integrity management program as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period, and recover the revenue requirement associated with the costs, subject to audit, through rate changes effective with the annual PGA in Oregon. Our SIP costs are tracked into rates annually, with rate recovery after the first $3.3 million of capital costs. An annual cap for expenditures has been set at $12 million, but extraordinary costs above the cap may be approved with written consent of the OPUC staff and other interested parties and approval of the OPUC. The SIP allows recovery of costs incurred in Oregon during the period from October 2008 through the effective date of our next general rate case. We do not have any special accounting or rate treatment for our SIP costs incurred in the state of Washington.

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

The WUTC has also authorized the deferral of environmental costs, if any, that are incurred in connection with services provided to Washington customers. The order granting approval of that request was effective January 26, 2011.

Pension Deferral. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates in our last general rate case, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility's authorized rate of return, which is currently 8.62 percent. The reduction to operations and maintenance expense for 2011 was $6.0 million. Future years' deferrals will depend on changes in plan assets and projected benefit liabilities using a number of key assumptions, as well as our pension contributions. We estimate deferrals totaling $8 million to $9 million in 2012. See "Application of Critical Accounting Policies and Estimates," above.

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Customer Credits for Gas Storage Sharing. In June 2011, $12.5 million was credited to Oregon utility customers from our regulatory incentive sharing mechanism related to gas storage and asset management services of pipeline capacity and gas storage at Mist (see "Gas Storage," below). In June 2010, we credited $11.0 million to customers under the same regulatory sharing mechanism. Our Washington utility customers receive their respective share of this credit as part of the annual PGA filing. In November 2011, a $0.9 million credit was placed in Washington utility customer rates for these activities, compared to a $1.2 million credit to Washington customers in November 2010.

Business Segments - Utility Operations

Utility net operating revenues (margins) are affected by customer growth, and to a certain extent, by changes in volume due to weather and customer consumption patterns because a significant portion of our revenues are derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff, which adjusts revenues to offset changes in margin resulting from increases or decreases in average use by residential and commercial customers, and a weather normalization tariff, which adjusts to offset changes in margin resulting from above- or below-average temperatures during the winter heating season (see "Results of Operations—Regulatory Matters—Rate Mechanisms," above). Both the conservation and weather normalization mechanisms have the effect of reducing the volatility of our utility earnings. We also have other regulatory mechanisms, which increase or decrease utility margins to account for other costs and revenues approved by the OPUC or WUTC. See "Results of Operations—Regulatory Matters—Rate Mechanisms," below.

2011 compared to 2010:

Our utility segment in 2011 earned $60.5 million, or $2.26 per share, compared to $66.3 million, or $2.49 per share in 2010. The major factors contributing to the change was a $14.9 million reduction in utility margins related to the repealed Oregon legislative rule on utility income taxes paid, including of a $7.4 million write-off in 2011 plus a $7.7 million revenue accrual recognized in 2010, and a net gain of $6.1 million recognized in 2010 related to a refund of property taxes plus accrued interest from a favorable tax ruling. These were partially offset by increases in residential and commercial customer margins of $11.3 million, including the effects of weather normalization and decoupling mechanisms, a slight gain in industrial customer margins of $0.2 million, and an increase in gas cost incentive sharing of $0.5 million. Total utility volumes sold and delivered in 2011 increased 9 percent over last year primarily due to the impact of colder weather on residential and commercial use.

Our weather normalization mechanism adjusted residential and commercial margins down by $13.1 million for the year ended December 31, 2011 based on weather that was 9 percent colder than average, compared to a margin increase of $14.0 million for the year ended December 31, 2010 when weather was 2 percent warmer than average. Our decoupling mechanism adjusted residential and commercial margins up by $19.3 million in 2011, after adjusting for expected price elasticity impacts from lower PGA prices effective November 1, 2010, compared to margin adjustments up by $15.5 million in 2010.

2010 compared to 2009:

Our utility segment in 2010 earned $66.3 million, or $2.49 per share, compared to $66.0 million, or $2.48 per share in 2009. The major factors contributing to the change were reduced operating expenses largely offset by lower utility margins. The lower margins consisted of a $13.5 million decrease from the prior year's gas cost incentive sharing, partially offset by a net $5 million increase from residential and commercial customers, including the effects of the weather normalization and decoupling mechanisms, and a $0.7 million increase in industrial margin. Total utility volumes sold and delivered in 2010 decreased by 6 percent over last year due to the effects of warmer weather on residential and commercial use and the lingering effects of a weak economy on commercial and industrial use. The regulatory adjustment for income taxes paid increased margin by $1.8 million compared to 2009.

Our weather normalization mechanism adjusted residential and commercial margins up by $14.0 million for the year ended December 31, 2010 based on weather that was 2 percent warmer than average, compared to a margin reduction of $15.2 million for the year ended December 31, 2009 when weather was 3 percent colder than average. Our decoupling mechanism adjusted residential and commercial margins up by $15.5 million in 2010, after adjusting for expected price elasticity impacts from lower PGA prices effective November 1, 2009, compared to margin adjustments totaling $11.6 million in 2009.

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The following table summarizes the composition of gas utility volumes and revenues for the years ended December 31, 2011, 2010 and 2009:

Thousands, except degree day and customer data	2011	2010	2009	Favorable/(Unfavorable) 2011 vs. 2010	2010 vs. 2009
Utility volumes - therms:					
Residential sales	425,139	368,682	412,867	56,457	(44,185)
Commercial sales	259,675	230,196	255,593	29,479	(25,397)
Industrial - firm sales	37,344	37,085	39,447	259	(2,362)
Industrial - firm transportation	129,898	127,796	124,218	2,102	3,578
Industrial - interruptible sales	59,308	58,387	72,525	921	(14,138)
Industrial - interruptible transportation	240,990	239,823	226,715	1,167	13,108
Total utility volumes sold and delivered	1,152,354	1,061,969	1,131,365	90,385	(69,396)
Utility operating revenues - dollars:					
Residential sales	$ 492,490	$ 456,174	$ 555,844	$ 36,316	$ (99,670)
Commercial sales	244,922	227,994	292,697	16,928	(64,703)
Industrial - firm sales	30,455	30,830	41,407	(375)	(10,577)
Industrial - firm transportation	6,250	5,702	5,671	548	31
Industrial - interruptible sales	34,961	36,164	62,116	(1,203)	(25,952)
Industrial - interruptible transportation	9,169	8,131	7,964	1,038	167
Regulatory adjustment for income taxes paid(1)	(7,162)	7,721	5,884	(14,883)	1,837
Other revenues	11,134	17,917	21,166	(6,783)	(3,249)
Total utility operating revenues	822,219	790,633	992,749	31,586	(202,116)
Cost of gas sold	458,508	424,494	611,088	(34,014)	186,594
Revenue taxes	20,741	19,991	24,656	(750)	4,665
Utility margin	$ 342,970	$ 346,148	$ 357,005	$ (3,178)	$ (10,857)
Utility margin:(2)					
Residential sales	$ 222,526	$ 197,045	$ 217,124	$ 25,481	$ (20,079)
Commercial sales	86,971	77,831	85,850	9,140	(8,019)
Industrial - sales and transportation	28,635	28,451	27,713	184	738
Miscellaneous revenues	4,875	4,658	6,670	217	(2,012)
Gain (loss) from gas cost incentive sharing	2,107	1,594	15,064	513	(13,470)
Other margin adjustments	(1,173)	(647)	2,308	(526)	(2,955)
Margin before regulatory adjustments	343,941	308,932	354,729	35,009	(45,797)
Weather normalization adjustment	(13,106)	13,996	(15,236)	(27,102)	29,232
Decoupling adjustment	19,297	15,499	11,628	3,798	3,871
Regulatory adjustment for income taxes paid(1)	(7,162)	7,721	5,884	(14,883)	1,837

Utility margin	$ 342,970	$ 346,148	$ 357,005	$ (3,178)	$ (10,857)
Customers - end of period:					
Residential customers	615,670	610,598	604,692	5,072	5,906
Commercial customers	62,948	62,489	62,169	459	320
Industrial customers	925	910	933	15	(23)
Total number of customers - end of period	679,543	673,997	667,794	5,546	6,203
Actual degree days	4,652	4,171	4,383		
Percent colder (warmer) than average weather(3)	9 %	(2) %	3 %		

(1) Regulatory adjustment for income taxes paid is described below.
(2) Amounts reported as margin for each category of customers are net of cost of gas sold and revenue taxes.
(3) Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, energy prices, competition from other energy sources and economic conditions in our service areas. Typically, 80 percent or more of our annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced due to our weather normalization mechanism in Oregon where about 90 percent of our customers are served. For more information on our weather mechanism, see "Regulatory Matters—Rate Mechanisms—Weather Normalization," above.

The primary changes that impacted margin from residential and commercial sales were as follows:

2011 compared to 2010:

- utility volumes were 14 percent higher, primarily reflecting 12 percent colder weather; sales volumes to core utility customers are sensitive to weather variations especially in the winter-heating season;
- utility operating revenues increased $53.2 million or 8 percent primarily due to the 14 percent volume increase;
- utility margin increased $11.3 million or 4 percent primarily due to customer growth of 0.8 percent and colder weather, with colder weather benefits partially offset by weather normalization adjustments that reduce customer bills and Company margins when weather is colder than average.

2010 compared to 2009:

- utility volumes were 10 percent lower, primarily reflecting 5 percent warmer weather, conservation efforts and weak economic conditions;
- utility operating revenues decreased $164.4 million or 19 percent primarily due to the 10 percent volume decline and customer rate decreases of 16 and 22 percent in Oregon and Washington, respectively, effective November 1, 2009; and
- utility margin increased $5 million or 2 percent primarily due to customer growth of 0.9 percent and the colder weather in the spring of 2010 that was not entirely offset by Oregon's weather normalization mechanism.

Industrial Sales and Transportation

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

2011 compared to 2010:

- volumes delivered to industrial customers increased 4.4 million therms, or 1 percent, reflecting increased energy demand, with the majority of the increased volume attributable to the manufacturing sector; and
- margins increased $0.2 million, or 1 percent.

2010 compared to 2009:

- volumes delivered to industrial customers increased 0.2 million therms; and
- margin increased $0.7 million, or 3 percent.

The slight margin increases in 2011 and 2010 were primarily due to an increase in industrial use of natural gas as a result of higher costs for oil and propane fuels, which caused some customers to switch to natural gas. Partially offsetting this trend was the loss of a few large industrial customers due to the economy.

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Regulatory Adjustment for Income Taxes Paid

From 2007 through 2010, Oregon law required the Company and certain regulated natural gas and electric utilities to annually review the amount of income taxes collected in rates from utility operations and compare it to the amount the utility actually pays to taxing authorities. Under this law, if the amount paid for income taxes related to utility operations is less than the amount collected from Oregon utility customers, then we were required to refund the excess to Oregon utility customers. Conversely, if the amount paid in income taxes was more than the amount collected from Oregon utility customers, then we were required to collect a surcharge from Oregon utility customers.

The Company's income tax review resulted in a surcharge to customers each year SB 408 was in effect. For 2009, the OPUC approved the Company's recovery of $5.1 million plus interest from customers. For the 2010 tax year, we originally estimated and accrued $7.1 million. However, when SB 967 was signed into law in May of 2011, it effectively repealed the regulatory adjustment for income taxes paid for the 2010 tax year and all years thereafter, thus resulting in the Company recording a $7.4 million write-off in the second quarter of 2011 to write-off the amount from SB 408, plus interest, related to 2010 tax year. Results related to SB 408 for 2011 were a pre-tax loss of $7.4 million, compared to pre-tax gains of $7.7 million in 2010 and $5.9 million in 2009.

SB 967 requires the OPUC to make decisions in future ratemaking proceedings on the amounts of income taxes to be recovered in customer rates. For additional information, see "Revenue Recognition" above under Application of Critical Accounting Policies and Estimates.

Other Revenues

Other revenues include miscellaneous fee income as well as regulatory revenue adjustments, which reflect current period deferrals to and prior year amortizations from, regulatory asset and liability accounts, except for gas cost deferrals which flow through cost of gas sold. Other revenues increased utility margins by $11.1 million in 2011, compared to $17.9 million in 2010 and $21.2 million in 2009.

2011 compared to 2010:

Other revenues decreased $6.8 to $11.1 million in 2011 primarily reflecting a decrease in the amortization of decoupling adjustments totaling $5.9 million and a decrease in other regulatory amortizations of $4.6 million, partially offset by a $1.0 million increase in the refund to utility customers related to gas storage incentive sharing mechanism and an increase in the current decoupling deferral of $3.8 million.

Decoupling amortizations and other regulatory amortizations from prior year deferrals are included in current or future revenues from residential, commercial and industrial firm customers.

2010 compared to 2009:

Other revenues decreased $3.2 to $17.9 in 2010 primarily reflecting an increase in the amortization of decoupling adjustments totaling $7.9 million, partially offset by a $4.0 million increase in the refund to utility customers related to gas storage incentive sharing mechanism.

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Cost of Gas Sold

The cost of gas sold includes gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, production from gas reserves, and company gas use. The OPUC and the WUTC generally require the natural gas commodity costs 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 can be 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 "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment and Regulatory Matters—Rate Mechanisms—Gas Reserves," above). We use natural gas commodity-based hedge contracts (derivatives), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage our exposure to rising gas prices. Gains and losses from financial hedge contracts are generally included in our PGA prices and normally do not impact net income because the hedge prices are usually 100 percent passed through to customers in annual rate changes, subject to a regulatory prudency review. However, utility hedge contracts entered into after the annual PGA rates are set in Oregon can impact net income because we would be required to share in any gains or losses compared to the corresponding commodity prices included in rates in the PGA. In Washington, 100 percent of the actual gas costs, including hedge gains and losses allocated to Washington gas sales, are passed through in customer rates (see "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," and "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above, and Note 15). The following summarizes the major factors that contributed to changes in cost of gas sold:

2011 compared to 2010:

- total cost of gas sold increased $34 million, or 8 percent, due to an 9 percent increase in total sales volumes partially offset by a 4 percent decrease in the average cost of gas sold per therm;
- the average gas cost collected through rates decreased from 61 cents per therm in 2010 to 59 cents per therm in 2011, primarily reflecting lower commodity prices that were passed through to PGA rate decreases effective November 1, 2010 and 2011; and
- hedge losses totaling $56.5 million were realized and included in cost of gas sold for the year ended December 31, 2011, compared to $61.0 million of hedge losses in the same period of 2010.

2010 compared to 2009:

- total cost of gas sold decreased $186.6 million, or 31 percent, due to a 6 percent decrease in total sales volumes and a 22 percent decrease in the average cost of gas sold per therm;
- the average gas cost collected through rates decreased from 78 cents per therm in 2009 to 61 cents per therm in 2010, primarily reflecting lower commodity prices that were passed through to PGA rate decreases effective November 1, 2009 and 2010; and
- hedge losses totaling $61.0 million were realized and included in cost of gas sold for the year ended December 31, 2010, compared to $187.9 million of hedge losses in the same period of 2009.

Actual gas costs in both 2011 and 2010 were slightly below those embedded in rates, while in 2009 actual gas costs were significantly lower. The effect on shareholders from the gas cost incentive sharing mechanism was a contribution to margin of $2.1 million in 2011, $1.6 million in 2010 and $15.1 million in 2009. For a discussion of our gas cost incentive sharing mechanism, see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above.

Gas Storage

Our gas storage segment consists of the non-utility portion of our Mist underground storage facility and our 75 percent ownership interest in the Gill Ranch facility. For the year ended December 31, 2011, we earned $4.1 million, or 15 cents per share, from gas storage compared to $6.1 million, or 23 cents per share, for 2010. The primary reason for the decline was lower storage pricing driven by lower, more stable gas costs.

At Mist, we provide gas storage services to customers in the interstate and intrastate markets primarily using storage capacity that has been developed in advance of core utility customers' requirements. Under a regulatory incentive sharing mechanism in Oregon, we retain 80 percent of pre-tax income from Mist gas storage services, and from asset management services, when the underlying costs of the capacity being used are not included in our utility rates, and 33 percent of pre-tax income from such storage and asset management services when the capacity being used is included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for credit to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage and asset management services.

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Our 75 percent undivided ownership interest in the Gill Ranch facility is held by our wholly-owned subsidiary Gill Ranch, which is also the operator of the project. Our portion of the facility is currently designed to provide 15 Bcf of gas storage capacity by the end of 2012. Gill Ranch commenced operations at the end of October 2010 and had approximately 13 Bcf of storage capacity available for contracting to customers beginning April 1, 2011, which was the beginning of the first full storage injection season at Gill Ranch, after a partial injection season, which commenced in October 2010. See Note 4.

Other

Our other business segment consists of NNG Financial, an investment in PGH, and other non-utility investments and business activities. NNG Financial had total assets of $1.1 million as of both December 31, 2011 and 2010 primarily reflecting a non-controlling minority interest in the Kelso-Beaver interstate gas transmission pipeline. Our equity investment in PGH as of December 31, 2011 and 2010 was $13.5 million and $14.8 million, respectively. Total earnings from our other business segment as of December 31, 2011 and 2010 was a net loss of $0.7 million and net income of $0.3 million, respectively. The loss for 2011 was primarily due to approximately $1.3 million of charges on our investment in PGH. See Note 4.

Consolidated Operations

Operations and Maintenance

Operations and maintenance expense was $125.3 million in 2011, compared to $121.0 million in 2010, an increase of $4.3 million or 4 percent. The following summarizes the major factors that contributed to changes in operations and maintenance expense:

2011 compared to 2010:

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

Partially offsetting the above factors were:

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

2010 compared to 2009:

- a $5.6 million decrease in utility payroll expense related to a reduced number of employees. There was a reduction of 105 employees or 9 percent over the two year period beginning January 2009;
- a $2.4 million decrease in utility bad debt expense (see further discussion below);
- a $1.9 million decrease in pension expense, due to the increase in market value of plan investments from contributions in 2009 and 2010;
- a $1.5 million decrease in health care and other employee benefit expense due to reduced employee count, offset by an increase in healthcare premiums (see further discussion below); and
- a $0.2 million decrease in damage claims in 2010.

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Partially offsetting the above increases were:

- a $4.9 million increase in gas storage expenses, primarily related to start-up costs including salaries and benefits, power costs, legal fees and investment bank consulting costs; and
- a $1.0 million increase for consulting and legal fees at the utility related to a successful property tax appeal.

Our bad debt expense as a percent of revenues was 0.23 percent for the year ended December 31, 2011, compared to 0.21 percent for the same period last year. The comparative increase in our bad debt expense ratio was largely due to lower than normal expense ratio in 2010 due to improved collections and higher recoveries of delinquent account balances. Despite the modest increase, we believe bad debt losses are comparable to last year and credit risks remain elevated due to the weak economy and high unemployment rates. Higher customer usage from colder weather these past few months may increase our exposure to credit losses in the near term, but we expect bad debt expense over the long term to remain below 0.5 percent of revenues.

Overall national healthcare spending has slowed as a result of the weak economy; however, healthcare trends for the cost of the services provided are forecasted to continue to rise at around 10 percent to 11 percent year over year. Initial projections for increases to employer paid premiums for 2012 are estimated to be between 7 percent and 9 percent. Based on our actual premium increase for 2012, NW Natural's employer paid portion of health premiums (medical, dental, vision) are expected to increase 6 percent.

In addition, total pension costs are expected to increase in 2012. However, effective January 1, 2011 the OPUC approved the deferral of utility pension expense above the amount recovered in rates, which was set in our last general rate case. The pension expense deferral is recorded to a regulatory balancing account, which reduced operations and maintenance expense by $6.0 million for 2011, and we expect additional cost deferrals to the pension balancing account in 2012 at or above the levels of 2011. For further explanation of the pension balancing account, see "Regulatory Matters—Rate Mechanisms—Pension Deferral," above.

General Taxes

General taxes, which are principally comprised of property and payroll taxes and regulatory fees, increased $5.4 million, or 23 percent, in 2011 compared to 2010, and decreased $4.4 million, or 16 percent, in 2010 compared to 2009. The major factors that contributed to changes in general taxes are:

2011 compared to 2010:

- a $5.2 million increase due to the refund of property taxes in 2010 pursuant to a favorable ruling from the Oregon Supreme Court regarding taxation of utility gas inventory held for sale (see further discussion below); and
- a $1.3 million increase in property taxes at Gill Ranch as a result of the first full year of operations.

2010 compared to 2009:

- a $5.2 million decrease due to the refund of property taxes received in 2010, as mentioned above, partially offset by an increase in property taxes related to a 2 percent increase in net utility plant balances.

Prior to 2011, we had been involved for a number of years in litigation with the ODOR over whether inventories held for sale were required to be taxed as personal property. In January 2010, the Oregon Supreme Court unanimously ruled in our favor, stating that these inventories were exempt from property tax. As a result of this ruling, we were entitled to a refund of approximately $5.2 million, plus accrued interest, for property taxes paid on inventories beginning with the 2002-03 tax year. We recognized a net $6.1 million increase in pre-tax income in the first quarter of 2010, which consisted of $5.2 million for the refund of property taxes, $1.9 million for accrued interest income, and $1.0 million of increased operations and maintenance expense for legal and consulting services. We received all of the property tax refunds in 2010.

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Depreciation and Amortization

Total depreciation and amortization expense in 2011 increased by $4.9 million, or 7 percent, as compared to a $2.3 million or 4 percent increase in 2010 over 2009. The increased expense in 2011 was primarily related to an increase of $3.7 million in Gill Ranch's depreciation, plus additional depreciation on investments in utility plant for customer growth and system improvements. The increased expense in 2010 was primarily related to $1.1 million of depreciation at Gill Ranch as they went into service in the fourth quarter of 2010, plus additional depreciation on investments in utility plant.

Other Income and Expense – Net

The following table provides details on other income and expense – net for the last three years:

Thousands	2011	2010	2009
Gains from company-owned life insurance	$2,247	$2,042	$3,416
Interest income	50	2,024	211
Income (loss) from equity investments	(1,641)	588	1,329
Net interest on deferred regulatory accounts	5,999	4,692	2,051
Gain (loss) on sale of investments	(96)	223	45
Other non-operating	(2,036)	(2,467)	(3,338)
Total other income and expense - net	$4,523	$7,102	$3,714

2011 compared to 2010:

Other income and expense – net decreased $2.6 million, primarily due to $1.9 million of interest income received from the property tax refund in 2010 which did not occur in 2011, a $1.4 million loss from equity investments due to Palomar charges (see Note 12), partially offset by a $1.3 million increase in interest and carrying costs from regulatory account balances largely due to smaller balances in gas costs between 2011 and 2010. See discussion of Palomar in "Strategic Opportunities—Pipeline Diversification" above.

2010 compared to 2009:

Other income and expense – net increased $3.4 million, primarily due to $1.9 million of interest income related to property tax refund plus a $2.6 million increase in interest from regulatory account balances largely due to smaller balances in gas costs between 2010 and 2009, partially offset by a $1.4 million decrease in income from life insurance due to higher policy gains realized in 2009.

Interest Expense – Net

Interest expense—net of amounts capitalized in 2011 decreased by $0.5 million, or 1 percent, compared to 2010, and increased in 2010 by $1.9 million, or 5 percent, compared to 2009. The current year decrease was primarily due to a $1.9 million savings from interest expense on long-term debt as a result of bonds that were redeemed in 2010, partially offset by a $1.1 million increase for gas storage interest expense related to the Gill Ranch base gas agreement, as well as the issuance of $50 million of 3.176 percent medium term notes (MTN's) in September 2011 and the issuance of $40 million of subsidiary senior secured notes with an average interest rate of 7.38 percent for Gill Ranch in November 2011. The increases in 2010 compared to 2009 reflect the issuance of long-term debt during 2009, which included $75 million of 5.37 percent MTN's issued in March 2009 and $50 million of 3.95 percent MTN's issued in July 2009, and higher short-term debt balances. Interest expense also reflects a lower average interest rate used in calculating the allowance for funds used during construction, which is referred to as AFUDC. AFUDC rates, comprised of short-term and long-term capital costs as appropriate, were 0.5 percent in 2011, 0.6 percent in 2010 and 1.0 percent in 2009.

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Income Tax Expense

The decrease in income tax expense of $6.1 million, or 12 percent, compared to 2010 was primarily due to lower pre-tax consolidated earnings. Effective tax rate for 2011 and 2010 was 40.4 percent, compared to 40.5 percent in 2010 and 38.3 percent in 2009. Income tax expense increased $2.8 million, or 6 percent, for the year ended December 31, 2010 compared to 2009, primarily due to higher pre-tax consolidated earnings and a slightly higher effective tax rate.

For the 2011 tax year, the lower effective tax rate was primarily due to a decrease in state tax expense (see further discussion below). For the 2010 tax year, the higher effective tax rate was primarily the result of increased amortization of our regulatory tax account on pre-1981 utility plant assets (see “Regulatory Matters—Rate Mechanisms,” above) and a lower non-taxable gain on company-owned life insurance. For more information on our income taxes, including a reconciliation between the statutory federal and state income tax rates and the effective rate, see Note 2 and Note 10.

In July 2009, the governor of Oregon signed House Bill 3405 establishing increases in the state income tax rate for corporations, and Oregon voters approved this legislation in January 2010. The corporate income tax rate in Oregon increased from 6.6 percent to 7.9 percent for tax years 2009 and 2010 when taxable income was greater than $250,000. For tax years 2011 and 2012, the state income tax rate decreased to 7.6 percent, and for years after 2012 the tax rate will return to 6.6 percent, except for corporations with taxable income over $10 million the tax rate will remain at 7.6 percent. Following existing accounting guidance on income taxes, we re-measured our deferred income tax assets and liabilities, resulting in an adjustment to increase the balance by $3.6 million in 2009. Approximately $3.5 million of the adjustment was attributed to our utility operations. As we anticipate future recovery in rates, we recorded a regulatory asset for the grossed up revenue requirement. With respect to our non-utility business segments, a $0.1 million adjustment was charged to income tax expense in 2009. In 2010 we decreased the deferred income tax liability by $0.8 million as a result of the decrease from 7.9 percent to 7.6 percent. This decrease was almost entirely attributable to the utility business.

Financial Condition

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45 to 50 percent common stock equity and 50 to 55 percent long-term and short-term debt. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources of financing are also used to fund long-term debt redemptions and short-term commercial paper maturities (see “Liquidity and Capital Resources,” below, and Notes 7 and 8). Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure was as follows for the years ended December 31, 2011 and 2010:

	December 31,			
	2011		2010	
Common stock equity	46.5	%	44.7	%

Long-term debt	41.7	%	38.1	%
Short-term debt, including current maturities of long-term debt	11.8	%	17.2	%
Total	100	%	100	%

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Liquidity and Capital Resources

At December 31, 2011, we had $5.8 million of cash and cash equivalents, compared to $3.5 million at December 31, 2010. We also had $4.0 million in restricted cash at Gill Ranch as of December 31, 2011, which is being held as collateral for long-term debt outstanding, compared to $0.9 million as of December 31, 2010, which was being held as collateral for equipment purchase contracts and construction loans. In order to maintain sufficient liquidity during periods of volatile capital markets, at times we will maintain higher cash balances, add short-term borrowing capacity, and potentially pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC, and our use of proceeds from utility specific issuances are restricted to certain utility purposes. Our use of retained earnings is not subject to those same restrictions.

For the utility segment, our short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, borrowings from multi-year credit facilities, cash available from surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use utility long-term debt proceeds to finance utility capital expenditures, refinance maturing debt of the utility and provide for general corporate purposes of the utility.

Capital markets over the past few years, including the commercial paper market, experienced significant volatility and tight credit conditions, but conditions have been improving as reflected by tighter credit spreads and increased access to new financing for investment grade issuers. With our current debt ratings (see “Credit Ratings,” below), we have been able to issue commercial paper and MTNs at attractive rates and have not needed to borrow from our back-up credit facilities. In the event that we are not able to issue new debt due to market conditions, we expect that our near term liquidity needs can be met by using cash balances or, for the utility segment, drawing upon our committed credit facilities. We also have a universal shelf registration filed with the SEC for the issuance of secured and unsecured debt or equity securities, subject to market conditions and regulatory approvals. As of December 31, 2011, we have OPUC approval to issue up to $125 million of additional MTNs under the existing shelf registration for approved purposes.

In the event that our senior unsecured long-term debt credit ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit or other form of collateral, which could expose us to additional cash requirements and may trigger significant increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on December 31, 2011, we could have been required to post up to $45.9 million of collateral to our counterparties, but that assumes our long-term debt ratings were downgraded to non-investment grade levels, which would be a very significant change from current rating levels for NW Natural (see Note 13 and “Credit Ratings,” below).

Additionally, in July 2010, the U.S. Congress passed and President Obama signed into law the “Wall Street Reform and Consumer Protection Act.” The legislation requires additional government regulation of derivative and over-the-counter transactions, and could expand collateral requirements. While we continue to evaluate the legislation to determine its impact, if any, on our hedging procedures, results of operations, financial position and liquidity, we do not expect to know the full impact of the legislation until final regulations implementing the legislation are issued.

Recent developments that may have a significant impact on our liquidity and capital resources include pension contribution requirements, tax benefits, and environmental expenditures and insurance recoveries. With respect to pension requirements, we expect to make significant contributions over the next seven years until we are fully funded under the Pension Protection Act rules (see “Pension Cost and Funding Status of Qualified Retirement Plans,” below). With respect to federal income tax liabilities, an extension was granted that allows us to take 100 percent bonus depreciation on qualified expenditures during 2011, and 50 percent bonus depreciation on a majority of our capital expenditures in 2012, which will significantly reduce our tax liability for the 2011 and 2012 tax years thereby providing cash flow benefits in late 2012 and 2013 (see “Cash Flows—Operating Activities,” below). With respect to environmental liabilities, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through insurance or utility rates over the next several years, although the amount and timing of these expenditures and recoveries is uncertain (see Note 15).

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Our storage segment's short-term liquidity is supported by cash balances, internal cash flow from operations, external financing, and to a certain extent on funding from its parent company. Gill Ranch has a limited operational history, having begun operations in October 2010. Although we anticipate operating cash flows to be sufficient for liquidity purposes, the amount and timing of these cash flows are uncertain. In November 2011, Gill Ranch issued $40 million of senior secured notes, with fixed interest rate component on $20 million and a variable interest rate on the remaining $20 million. The average combined interest rate on the notes was 7.38 percent per annum in 2011. These notes are secured by our membership interest in Gill Ranch Storage, LLC, and are nonrecourse to NW Natural. The maturity date of these notes is November 30, 2016.

Under the note agreements, Gill Ranch is subject to certain covenants and restrictions, including but not limited to, a financial covenant that requires Gill Ranch to maintain minimum adjusted EBITDA at various levels over the term of the notes. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the agreements, Gill Ranch is also subject to a debt service reserve requirement of 10 percent of the outstanding principal amount, initially $4 million, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on incurrence of additional debt.

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

Dividend Policy

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

Off-Balance Sheet Arrangements

Except for certain lease and purchase commitments (see "Contractual Obligations," below), we have no material off-balance sheet financing arrangements.

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Contractual Obligations

The following table shows our contractual obligations at December 31, 2011 by maturity and type of obligation.

	Payments Due in Years Ending December 31,						
Thousands	2012	2013	2014	2015	2016	Thereafter	Total
Commercial paper	$141,600	$-	$-	$-	$-	$-	$141,600
Long-term debt maturities	40,000	-	60,000	40,000	65,000	476,700	681,700
Interest on long-term debt	39,056	38,145	37,984	36,489	33,518	228,311	413,503
Postretirement benefit payments(1)	21,430	21,703	22,245	22,789	23,482	133,978	245,627
Capital leases	443	313	118	23	-	-	897
Operating leases	4,929	4,841	5,078	5,042	5,018	24,659	49,567
Gas purchases(2)	98,534	18,331	15,290	5,651	-	-	137,806
Gas pipeline commitments	94,491	87,983	82,898	72,316	61,358	287,541	686,587
Gas reserves(3)	59,040	51,660	49,200	41,820	-	-	201,720
Other purchase commitments	-	157	82	37	-	13,559	13,835
Total	$499,523	$223,133	$272,895	$224,167	$188,376	$1,164,748	$2,572,842

(1) The majority of postretirement benefit payments are related to our qualified defined benefit pension plans, which are funded by plan assets and future cash contributions. See Note 9.
(2) Gas purchases include contracts which use price formulas tied to monthly index prices, plus hedged derivative liabilities. Commitment amounts are based on futures prices as of December 31, 2011. For a summary of derivatives/liabilities, see Note 13. For a summary of gas purchase commitments, see Note 15.
(3) Gas reserves contracts include provisions for cancelation, under which further payment would not be required.

Other purchase commitments primarily consist of remaining balances under existing purchase orders. These and other contractual obligations are financed with cash from operations and from issuance of short-term debt, which is periodically refinanced through the sale of long-term debt or equity securities.

At December 31, 2011, 598 of our utility employees were members of the Office and Professional Employees International Union Local No. 11. In July 2009, these union employees and the Company agreed to a new five-year labor agreement called the Joint Accord. The Joint Accord provides for a one percent automatic wage increase each year, plus the potential for us to an additional two percent based on wage inflation and other factors. It also provides competitive health benefits while limiting the cost increases for these benefits to the same level as the annual wage increases. The term of the new Joint Accord extends to May 31, 2014, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement.

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas inventories and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities (see "Credit Agreements," below). Our commercial paper program did not experience any liquidity disruptions as a result of the credit problems that affected issuers of asset-backed commercial paper and certain other commercial paper programs over the last several years. At December 31, 2011 and 2010, our utility had commercial paper outstanding of $141.6 million and $257.4 million, respectively. The effective interest rate on the utility's commercial paper outstanding at December 31, 2011 and 2010 was 0.3 percent and 0.4 percent, respectively.

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In March 2009, Gill Ranch entered into a cash collateralized credit facility for up to $40 million, which was extended through September 30, 2010. In June 2010, Gill Ranch repaid its $40 million bank loan outstanding using the proceeds from its cash collateralized account. The effective interest rate on the Gill Ranch credit facility was 0.8 percent during 2010.

Credit Agreements

We have a syndicated multi-year credit agreement for unsecured revolving loans totaling $250 million. The original term of this credit agreement was extended through May 31, 2013. All lenders under our syndicated agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2011 (see table below). We also had three bilateral credit agreements totaling $50 million in effect from November 30, 2010 through March 31, 2011 for seasonal working capital needs.

Lender rating, by category	Loan Commitment (In Thousands) Syndicated Facility	
AAA/Aaa	$	-
AA/Aa		230,000
A/A		20,000
BBB/Baa		-
Total	$	250,000

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

As discussed above, we extended commitments with all of our lenders under the $250 million syndicated agreement through May 31, 2013. This syndicated agreement also allows us to request increases in the total commitment amount from time to time, up to a maximum amount of $400 million. This syndicated agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment.

Any principal and unpaid interest amounts owed on borrowings under the credit agreements are due and payable on or before the maturity date. There were no outstanding balances under these credit agreements at December 31, 2011 and 2010. These agreements require us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2011 and 2010, with consolidated indebtedness to total capitalization ratios of 53.5 percent and 55.4 percent, respectively.

The syndicated agreement also requires that we maintain credit ratings with S&P and Moody's and notify the lenders of any change in our senior unsecured debt ratings by such rating agencies. A change in our debt ratings by S&P or by Moody's is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. However, a change in our debt rating below BBB- by S&P or Baa3 by Moody's would require additional approval from the OPUC prior to issuance of utility debt, and interest rates on any loans outstanding under the credit agreements are tied to debt ratings, which would increase or decrease the cost of any loans under the credit agreements when ratings are changed (see "Credit Ratings," below).

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Credit Ratings

Our debt credit ratings are a factor in our liquidity, affecting our access to the capital markets, including the commercial paper market. Our debt credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. A change in our ratings below BBB- by S&P or Baa3 by Moody's would require additional approval from the OPUC prior to our issuing additional long-term debt.

The following table summarizes our NW Natural debt ratings from S&P and Moody's at December 31, 2011:

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

The above credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Redemptions of Long-Term Debt

We redeemed MTN's during 2011, 2010 and 2009 as follows:

	Amounts Redeemed		
Thousands (Years ended December 31)	2011	2010	2009
Medium-Term Notes			
6.65% Series B due 2027 (1)	$-	$-	$300
4.11% Series B due 2010	-	10,000	-
7.45% Series B due 2010	-	25,000	-
6.665% Series B due 2011	10,000	-	-
	$10,000	$35,000	$300

(1) In November 2009, $0.3 million of our 6.65 percent secured MTNs due 2027 were redeemed pursuant to a one-time put option. This one-time put option has now expired, and the $19.7 million remaining principal outstanding is expected to be paid at maturity in November 2027.

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Cash Flows

Operating Activities

2011 compared to 2010:

For the year ended December 31, 2011, cash flow from operating activities totaled $233.5 million compared to $126.5 million in 2010 and $240.3 million in 2009. The significant factors contributing to changes in operating cash flow in 2011 compared to 2010 are as follows:

- an increase of $85.7 million from accrued taxes, primarily related to bonus depreciation which resulted in federal tax refunds of $36.6 in 2011 and a net operating loss (NOL) carryforward;
- an increase of $34.7 million from changes in deferred gas costs, which reflects a higher level of gas cost savings which will be refunded to utility customers in subsequent years' PGA;
- an increase of $33.4 million from insurance recoveries for environmental claims, net of deferred environmental expenditures in 2011;
- an increase of $12.0 million from changes in accounts payable due to decreased construction activity at Gill Ranch;
- a decrease of $29.5 million from changes in deferred tax liabilities primarily reflecting higher tax benefits in 2010 compared to 2011, largely driven by utility and Gill Ranch bonus depreciation for investments placed in service during 2010;
- a decrease of $22.1 million from changes in receivables primarily due to higher balances at the end of 2009, which benefitted cash flows during 2010; and
- a decrease of $12.0 million from higher pension contributions due to a decline in interest rates and asset values, which increased pension funding requirements.

In September 2010, Congress passed the Unemployment Insurance, Reauthorization and Job Creation Act of 2010 (the Jobs Act) and the legislation was signed into law by President Obama. The Jobs Act extended for one year the temporary bonus depreciation rules first enacted in the Economic Stimulus Act of 2008 and subsequently renewed in the American Recovery and Reinvestment Act of 2009. Under the bonus depreciation provision, and additional first-year tax deduction was allowed for depreciation equal to 50 percent of the adjusted basis of qualified property through September 8, 2010, in the year the property was placed in service, with the remaining percentage recovered under the normal depreciation rules. In addition, on December 17, 2010, President Barack Obama signed into law the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the Tax Relief Act), which allows 100 percent bonus depreciation for qualified property placed in service between September 9, 2010 through December 31, 2011. It also extended the 50 percent bonus depreciation deduction to qualifying property placed in service in 2012. As a result of this legislation, we generated a tax net operating loss in 2010 which was carried back to the tax year 2009, resulting in a federal income tax refund of $22.3 million which we received in 2011. We also recognized an increase in our cash flow by reducing our current tax liabilities for the 2011 and 2012 tax years. As of December 31, 2011, we have a federal and state income tax receivable balance of $7.0 million, which we expect to realize in cash flows during 2012.

2010 compared to 2009:

- an increase of $39.6 million from deferred income taxes, primarily reflecting higher tax benefits from bonus depreciation taken in 2010 related to Gill Ranch capital investments placed in service;
  - an increase of $15.0 million from a smaller pension contribution in 2010 compared to 2009;

- an increase of $10.1 million from the 2009 settlement of an interest rate hedge;
- a decrease of $75 million from accrued taxes, primarily related to 2010 benefits that will be refunded in 2011, and due to tax refunds received in 2009 related to a change in tax accounting method for repairs and maintenance costs;
- a decrease of $62.9 million from changes in deferred gas cost regulatory account which reflects actual gas prices compared to estimated gas prices embedded in customer rates;
- a decrease of $19.7 million from changes in receivables primarily due to higher balances at the end of 2008, which benefitted cash flows during 2009;
- a decrease of $14.5 million from changes in inventories primarily due to higher price of gas in inventory at the end of 2008, which benefitted cash flows during 2009 as higher cost inventories were recovered through utility rates; and
- a decrease of $13.0 million in accounts payable due to decreased Gill Ranch construction activity at the end of 2010 compared to the end of 2009.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations. For information on cash flow requirements related to leases and other purchase commitments, see “Contractual Obligations,” above and Note 15.

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Investing Activities

Cash used in investing activities for the year ended December 31, 2011 totaled $153.1 million, down from $212.9 million for the same period in 2010. Our capital expenditures were $100.5 million in the year ended December 31, 2011, down from $248.5 million for the same period in 2010. Capital expenditures decreased in non-utility construction activity in 2011, which were largely due to Gill Ranch construction expenditures in 2010. We also invested $50.6 million in utility gas reserves in 2011 under the agreement with Encana discussed earlier.

Restricted cash decreased $37.7 million compared to 2010, due to settling our $40 million cash collateralized loan in June 2010, partially offset by a $4 million restricted cash collateral requirement imposed under the new Gill Ranch debt issued in 2011 (see Financing Activities, below).

Over the five-year period 2012 through 2016, total utility capital expenditures are estimated to be between $400 and $500 million and utility expenditures for gas reserves are estimated to be $200 million. The estimated level of utility capital expenditures over the next five years reflects assumptions for customer growth, storage development for the utility, technology investments and utility distribution improvements, including requirements under current pipeline safety programs. Most of the required funds are expected to be internally generated over the five-year period, and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing.

In 2012, we expect to spend less than $15 million on non-utility development projects, including the storage businesses and Palomar. Storage business capital expenditures in 2012 are expected to be paid primarily from working capital, and potentially with additional funds from NW Natural. Palomar expects to continue working on revised plans for the east pipeline segment, including plans to conduct an open season to re-evaluate regional needs. The initial planning and permitting costs have been financed with equity funds from NW Natural and our partner, TransCanada American Investments Ltd. For more information, see Note 12 and “Strategic Opportunities—Pipeline Diversification,” above.

Financing Activities

Cash used in financing activities for the year ended December 31, 2011 totaled $78.0 million, down significantly from cash provided of $81.4 million for the same period in 2010. Our short-term debt balances decreased $115.8 million for the year ended December 31, 2011, compared to an increase of $155.4 million for the same period in 2010. We also redeemed $10 million of long-term debt in June of 2011. This was offset by long-term debt issuances of $50 million in September 2011 by the utility and $40 million in November 2011 by Gill Ranch. We continue to use long-term debt proceeds primarily to finance capital expenditures, refinance short-term and long-term debt maturities as well as for general corporate purposes.

We have a repurchase program approved through May 2011 which provides authorization to repurchase up to 2.8 million shares of NW Natural common stock or up to $100 million. The purchases are made in the open market or through privately negotiated transactions. No repurchases were made in 2011, 2010 or 2009 under the program. Since the program’s inception, we have repurchased an aggregate 2.1 million shares of common stock at a total cost of $83.3 million, at the average price of $39.19 per share (see Part II, Item 5, “Market for the Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities,” above).

Free Cash Flow

Free cash flow is the amount of cash remaining after the payment of all cash expenses, capital expenditures and investment activities, and dividends. Free cash flow is a non-GAAP financial measure, but we believe this supplemental information enables the reader of the financial statements to better understand our cash generating ability of the Company and to benefit from seeing cash flow results from management's perspective in addition to the traditional GAAP presentation. We monitor free cash flow as one measure of our return on investments.

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Provided below is a reconciliation from cash provided by operations (GAAP basis) to our non-GAAP free cash flow.

Thousands	2011	2010	2009
Cash provided by operating activities	$233,462	$126,469	$240,335
Cash used in investing activities	(153,065)	(212,871)	(162,141)
Cash dividend payments on common stock	(46,690)	(44,652)	(42,415)
Free cash flow	$33,707	$(131,054)	$35,779

The free cash flow information presented above is not intended to be a substitute for, nor is it meant to be a better measure of, cash flow results prepared in accordance with GAAP. In addition, the non-GAAP measure we provide may be calculated differently by other companies that present a similar non-GAAP financial measure for cash flow.

Pension Cost and Funding Status of Qualified Retirement Plans

Pension costs are determined in accordance with accounting standards for compensation and retirement benefits (see "Application of Critical Accounting Policies and Estimates – Accounting for Pensions and Postretirement Benefits," above). Pension costs for our two qualified defined benefit plans, which are allocated between operation and maintenance expenses, capital expenditures and the deferred regulatory balancing account totaled $16.3 million in 2011, an increase of $4.9 million from 2010. See Note 9 for additional details.

The fair market value of pension assets in these two plans decreased to $216.0 million at December 31, 2011 from $219.0 million at December 31, 2010. The decrease was due to a negative return on plan assets of $6.7 million and benefit payments of $16.6 million, offset by $20.2 million in employer contributions.

We make contributions to company-sponsored qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plans were underfunded by $146.9 million at December 31, 2011. We plan to make contributions during 2012 of approximately $28 million. For more information on the funding status of our qualified retirement plans and other postretirement benefits, see Note 9.

We also contribute to a multiemployer pension plan for our employees (the Union Plan, or otherwise known as Western States Plan) pursuant to our collective bargaining agreement. We made contributions totaling $0.4 million to the Union Plan in both 2011 and 2010. See Note 9 for further disclosures.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2011, 2010 and 2009, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.41, 3.73, and 3.86, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. See Exhibit 12.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies (see “Application of Critical Accounting Policies and Estimates,” above). At December 31, 2011, we had a regulatory asset of $105.7 million for deferred environmental costs. If it is determined that both the insurance recovery and future customer rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 15.

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New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Supply Risk

We enter into spot, short-term and long-term natural gas supply contracts, along with associated pipeline transportation contracts, to manage our commodity supply risk. Historically, we have arranged for physical delivery of an adequate supply of gas, including gas in our Mist storage facility, to meet the expected requirements of our core utility customers. Our gas purchase contracts are primarily index-based and subject to monthly re-pricing, a strategy that is intended to reflect market price trends during the upcoming year.

Commodity Price and Storage Value Risk

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

Interest Rate Risk

We are exposed to interest rate risk primarily associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is primarily managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, options and other hedging instruments, to manage and mitigate interest rate exposure.

Foreign Currency Risk

The costs of certain natural gas commodity supplies and certain pipeline services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange rates for our commodity and commodity related demand charges paid in Canadian dollars. At December 31, 2011 and 2010, notional amounts under foreign currency forward contracts totaled $12.3 million and $13.9 million, respectively. As of December 31, 2011 , all foreign currency forward contracts mature within one year. If all of the foreign currency forward contracts had been settled on December 31, 2011, a loss of $0.2 million would have been realized (see Note 13).

Credit Risk

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

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Credit exposure to financial derivative counterparties. Based on estimated fair value at December 31, 2011, our overall credit exposure relating to commodity hedge contracts is considered to be immaterial as it reflects amounts we owed to our financial derivative counterparties totaling $63.5 million. However, changes in natural gas prices could result in counterparties owing us money. Therefore our financial derivatives policy requires counterparties to have at least an investment-grade credit rating at the time the derivative instrument is entered into, and specific limits on the contract amount and duration based on each counterparty's credit rating. Due to potential changes in market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor and manage our derivative credit exposure and place counterparties on hold for trading purposes or require cash collateral, letters of credit or guarantees as circumstances warrant. As of December 31, 2011, we do not have any actual derivative credit risk exposure, which reflects amounts that financial derivative counterparties owe to us.

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

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)	
Thousands	2011	2010
AAA/Aaa	$ -	$ -
AA/Aa	(57,542)	(43,656)
A/A	(5,924)	(9,017)
BBB/Baa	-	-
Total	$ (63,466)	$ (52,673)

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

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

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

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Weather Risk

We are exposed to weather risk primarily from our regulated utility business. A large percentage of our utility margin is volume driven, and current rates are based on an assumption of average weather. In 2003, the OPUC approved a weather normalization mechanism for residential and commercial customers. This mechanism affects customer bills between December 1 through May 15 of each winter heating season, increasing or decreasing the margin component of customers' rates to reflect gas usage based on "average" weather using the 25-year average temperature for each day of the billing period. The mechanism is intended to stabilize the recovery of our utility's fixed costs and reduce fluctuations in customers' bills due to colder or warmer than average weather. Customers in Oregon are allowed to opt out of the weather normalization mechanism. As of December 31, 2011, approximately 9 percent of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 10 percent of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by a weather normalization mechanism is less than 20 percent of all residential and commercial customers.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

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

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MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America (GAAP). Our internal control over financial reporting includes those policies and procedures that:

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

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

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

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on our assessment and those criteria, management has concluded that we maintained effective internal control over financial reporting as of December 31, 2011.

The effectiveness of internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

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

/s/ David H. Anderson
David H. Anderson
Senior Vice President and Chief Financial Officer

February 28, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying table of contents present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying table of contents presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
February 28, 2012

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Thousands, except per share amounts (year ended December 31)	2011	2010	2009
Operating revenues:			
Gross operating revenues	$848,796	$812,106	$1,012,711
Less: Cost of sales	458,622	424,534	611,168
Revenue taxes	20,741	19,991	24,656
Net operating revenues	369,433	367,581	376,887
Operating expenses:			
Operations and maintenance	125,303	120,980	127,104
General taxes	29,281	23,872	28,253
Depreciation and amortization	70,004	65,124	62,814
Total operating expenses	224,588	209,976	218,171
Income from operations	144,845	157,605	158,716
Other income and expense - net	4,523	7,102	3,714
Interest expense - net	42,088	42,578	40,637
Income before income taxes	107,280	122,129	121,793
Income tax expense	43,382	49,462	46,671
Net income	63,898	72,667	75,122
Other comprehensive income:			
Change in employee benefit plan liability, net of taxes of $1,161 for 2011, $674 for 2010 and $1,273 for 2009	(1,779)	(1,027)	(1,936)
Amortization of non-qualified employee benefit plan liability, net of taxes of ($383) for 2011, ($257) for 2010 and ($58) for 2009	583	391	354
Comprehensive income	$62,702	$72,031	$73,540
Average common shares outstanding:			
Basic	26,687	26,589	26,511
Diluted	26,744	26,657	26,576
Earnings per share of common stock:			
Basic	$2.39	$2.73	$2.83
Diluted	$2.39	$2.73	$2.83
Dividends declared per share of common stock	$1.75	$1.68	$1.60

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2011	2010
Assets:		
Current assets:		
Cash and cash equivalents	$5,833	$3,457
Restricted cash	-	924
Accounts receivable	77,449	67,969
Accrued unbilled revenue	61,925	64,803
Allowance for uncollectible accounts	(2,895)	(2,950)
Regulatory assets	94,673	52,714
Derivative instruments	2,853	2,245
Inventories	74,363	80,385
Gas reserves	4,463	-
Income taxes receivable	7,045	41,066
Other current assets	22,980	19,652
Total current assets	348,689	330,265
Non-current assets:		
Property, plant and equipment	2,661,102	2,576,402
Less accumulated depreciation	767,226	722,239
Total property, plant and equipment - net	1,893,876	1,854,163
Gas reserves	47,451	-
Regulatory assets	371,392	348,897
Derivative instruments	-	628
Other investments	68,263	69,094
Restricted cash	4,000	-
Other non-current assets	12,903	13,569
Total non-current assets	2,397,885	2,286,351
Total assets	$2,746,574	$2,616,616

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2011	2010
Capitalization and liabilities:		
Capitalization:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,756 and 26,668 at December 31, 2011 and 2010, respectively	$348,383	$342,978
Retained earnings	373,905	356,727
Accumulated other comprehensive loss	(7,800)	(6,604)
Total common stock equity	714,488	693,101
Long-term debt	641,700	591,700
Total capitalization	1,356,188	1,284,801
Current liabilities:		
Short-term debt	141,600	257,435
Current maturities of long-term debt	40,000	10,000
Accounts payable	86,300	93,243
Taxes accrued	10,747	10,579
Interest accrued	5,857	5,182
Regulatory liabilities	31,046	17,828
Derivative instruments	57,317	38,437
Other current liabilities	41,597	35,457
Total current liabilities	414,464	468,161
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	413,209	373,409
Regulatory liabilities	278,382	258,031
Pension and other postretirement benefit liabilities	201,530	144,250
Derivative instruments	6,536	17,022
Other non-current liabilities	76,265	70,942
Total deferred credits and other non-current liabilities	975,922	863,654
Commitments and contingencies (see Note 15)	-	-
Total capitalization and liabilities	$2,746,574	$2,616,616

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Thousands	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at Dec. 31, 2008	$336,754	$296,005	$ (4,386)	$628,373
Comprehensive income	-	75,122	(1,582)	73,540
Restricted stock amortizations	39	-	-	39
Dividends paid on common stock	-	(42,415)	-	(42,415)
Tax benefits from employee stock option plan	229	-	-	229
Stock-based compensation	(776)	-	-	(776)
Issuance of common stock	1,115	-	-	1,115
Balance at Dec. 31, 2009	337,361	328,712	(5,968)	660,105
Comprehensive income	-	72,667	(636)	72,031
Dividends paid on common stock	-	(44,652)	-	(44,652)
Tax expense from employee stock option plan	(125)	-	-	(125)
Stock-based compensation	554	-	-	554
Issuance of common stock	5,188	-	-	5,188
Balance at Dec. 31, 2010	342,978	356,727	(6,604)	693,101
Comprehensive income	-	63,898	(1,196)	62,702
Dividends paid on common stock	-	(46,690)	-	(46,690)
Tax expense from employee stock option plan	(26)	-	-	(26)
Stock-based compensation	1,769	-	-	1,769
Issuance of common stock	3,632	-	-	3,632
Common stock expense	30	(30)	-	-
Balance at Dec. 31, 2011	$348,383	$373,905	$ (7,800)	$714,488

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

Thousands (year ended December 31)	2011	2010	2009
Operating activities:			
Net income	$63,898	$72,667	$75,122
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	70,004	65,124	62,814
Undistributed earnings from equity investments	1,329	(588)	(1,329)
Non-cash expenses related to qualified defined benefit pension plans	7,191	8,009	9,914
Contributions to qualified defined benefit pension plans	(22,045)	(10,000)	(25,000)
Deferred environmental expenditures, net of recoveries	25,586	(7,826)	(10,069)
Settlement of interest rate hedge	-	-	(10,096)
Other	(1,049)	(2,265)	(3,461)
Changes in assets and liabilities:			
Receivables	(6,246)	15,830	35,506
Inventories	6,022	572	15,110
Taxes accrued	34,189	(51,524)	23,461
Accounts payable	148	(11,846)	1,188
Interest accrued	675	(253)	8,582
Deferred gas costs	8,565	(26,090)	36,819
Deferred tax liabilities	46,877	76,410	36,775
Other - net	(1,682)	(1,751)	(15,001)
Cash provided by operating activities	233,462	126,469	240,335
Investing activities:			
Capital expenditures	(100,534)	(248,505)	(135,124)
Utility gas reserves	(50,597)	-	-
Restricted cash	(3,076)	34,619	(30,524)
Other	1,142	1,015	3,507
Cash used in investing activities	(153,065)	(212,871)	(162,141)
Financing activities:			
Common stock issued - net	3,040	4,598	(375)
Long-term debt issued	90,000	-	125,000
Long-term debt retired	(10,000)	(35,000)	(300)
Change in short-term debt	(115,835)	155,435	(158,851)
Cash dividend payments on common stock	(46,690)	(44,652)	(42,415)
Other	1,464	1,046	263
Cash provided by (used in) financing activities	(78,021)	81,427	(76,678)
Increase (decrease) in cash and cash equivalents	2,376	(4,975)	1,516
Cash and cash equivalents - beginning of period	3,457	8,432	6,916
Cash and cash equivalents - end of period	$5,833	$3,457	$8,432
Supplemental disclosure of cash flow information:			
Interest paid	$41,413	$41,037	$36,762
Income taxes paid	$1,756	$22,600	$10,000

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Principles of Consolidation

The accompanying consolidated financial statements represent the consolidation of Northwest Natural Gas Company (NW Natural) and all companies that we directly or indirectly control, either through majority ownership or otherwise. Our direct and indirect wholly-owned subsidiaries 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). Investments in corporate joint ventures and partnerships that we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method or the cost method, which includes NWN Energy's investment in Palomar Gas Holdings, LLC (PGH). NW Natural and its affiliated companies are collectively referred to herein as "NW Natural." The consolidated financial statements are presented after elimination of all significant intercompany balances and transactions, except for amounts required to be included under regulatory accounting standards to reflect the effect of such regulation. In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage business and other non-utility investments and business activities.

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

2. Summary of Significant Accounting Policies

Use of Estimates

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

Industry Regulation

Our principal businesses are the distribution of natural gas, which is regulated by the Public Utility Commission of Oregon (OPUC) and Washington Utilities and Transportation Commission (WUTC), and natural gas storage services, which are regulated by either the Federal Energy Regulatory Commission (FERC) or the California Public Utilities Commission (CPUC), and to a certain extent by the OPUC. Accounting records and practices of our regulated businesses conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with U.S. GAAP. Our businesses regulated by the OPUC, WUTC and FERC earn a reasonable return on invested capital from approved cost-based rates, while our business regulated by the CPUC earns a return to the extent we are able to charge competitive prices above our costs (i.e. market-based rates).

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC, which provides for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge in most cases.

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At December 31, 2011 and 2010, the amounts deferred as regulatory assets and liabilities were as follows:

	Regulatory Assets	
Thousands	2011	2010
Current:		
Unrealized loss on derivatives(1)	$57,317	$38,437
Pension and other postretirement benefit liabilities(2)	15,491	10,988
Other(3)	21,865	3,289
Total current	$94,673	$52,714
Non-current:		
Unrealized loss on derivatives(1)	$6,536	$17,022
Income tax asset	65,264	72,341
Pension and other postretirement benefit liabilities(2)	170,512	118,248
Environmental costs(4)	105,670	114,311
Other(3)	23,410	26,975
Total non-current	$371,392	$348,897

	Regulatory Liabilities	
Thousands	2011	2010
Current:		
Gas costs	$17,994	$15,583
Unrealized gain on derivatives(1)	2,853	2,245
Other(3)	10,199	-
Total current	$31,046	$17,828
Non-current:		
Gas costs	$8,420	$2,297
Unrealized gain on derivatives(1)	-	628
Accrued asset removal costs	267,355	252,941
Other(3)	2,607	2,165
Total non-current	$278,382	$258,031

(1) An unrealized gain or loss on derivatives does not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment mechanism when realized at settlement.

(2) Certain pension and other postretirement benefit liabilities of the utility are approved for regulatory deferral, including amounts recorded to the pension cost balancing account to defer the effects of higher and lower pension expenses. Such amounts include an interest component when recognized in net periodic benefit costs or earn a rate of return or carrying charge (see Note 9).

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

(4) Environmental costs are related to those sites that are approved for regulatory deferral. In Oregon, we earn a rate of return on amounts paid, whereas amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended. Environmental costs related to Washington were deferred beginning in 2011, with cost recovery and carrying charge to be determined in a future proceeding.

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

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We believe that continued application of regulatory accounting for these activities is appropriate and consistent with the current regulatory environment, and that all regulated assets and liabilities at December 31, 2011 and 2010 will be recoverable or refundable through future rate making decisions. We annually review all regulatory assets and liabilities for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings.

New Accounting Standards

Adopted Standards

Fair Value Disclosures. In January 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance on new fair value measurements and disclosures. This guidance requires additional disclosures for fair value measurements that use significant assumptions not observable in active markets (i.e. level 3 valuations), including a roll-forward schedule. These changes were effective for periods beginning after December 15, 2010; however, we elected to early adopt these disclosure requirements, as shown in Note 9. The adoption of this standard did not have a material effect on our financial statement disclosures.

Comprehensive Income. In June 2011, the FASB issued authoritative guidance on the presentation of comprehensive income within the financial statements. An entity can elect to present items of net income and other comprehensive income in one continuous statement — referred to as the statement of comprehensive income — or in two separate, but consecutive, statements. These changes are effective for periods beginning after December 15, 2011. We have elected to early adopt this standard and present net income and other comprehensive income in one continuous statement.

Multiemployer Pension Plans. In September 2011, the FASB issued authoritative guidance regarding multiemployer pension plan disclosures. The revised standard is intended to provide more information about an employer's financial obligations to a multiemployer pension plan and, therefore, help financial statement users better understand the financial health of all significant plans in which the employer participates. This standard has been adopted as shown in Note 9.

Recent Accounting Pronouncements

Fair Value Measurement. In May 2011, the FASB issued amendments to the authoritative guidance on fair value measurement. The amendments are primarily related to disclosure requirements, which go into effect for periods beginning after December 15, 2011. Early implementation is not allowed, and we are currently assessing the impact on our financial statement disclosures.

Balance Sheet Offsetting. In December 2011, the FASB issued authoritative guidance regarding the offsetting of assets and liabilities on the balance sheet. The revised standard is intended to provide more comparable guidance between the U.S. GAAP and international accounting standards by requiring entities to disclose both gross and net amounts for assets and liabilities offset on the balance sheet as well as other disclosures concerning their enforceable master netting arrangements. This guidance is effective for annual reporting periods beginning after January 1, 2013 and we are currently assessing the impact on our financial statement disclosures.

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Plant, Property and Accrued Asset Removal Costs

Plant and property are stated at cost, including capitalized labor, materials and overhead (see Note 11). In accordance with regulatory accounting standards, the cost of acquiring and constructing long-lived plant and property generally includes an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the regulatory financing cost incurred when debt and equity funds are used for construction (see “Allowance for Funds Used During Construction,” below). When constructed assets are subject to market-based rates rather than cost-based rates, then the financing cost incurred during construction are included in capitalized interest in accordance with U.S. GAAP, not regulatory financing cost under AFUDC.

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

Our provision for depreciation of utility plant and property is computed under the straight-line method in accordance with engineering studies approved by regulatory authorities. The weighted average depreciation rate for utility assets in service was approximately 2.8 percent in 2011 and 2010, and 2.9 percent in 2009 reflecting the approximate average economic life of the property. This includes 2011 weighted average depreciation rates for the following asset categories: 2.7 percent for transmission and distribution plant, 2.2 percent for gas storage facilities, 4.6 percent for general plant, and 5.1 percent for intangible and other fixed assets.

Allowance for Funds Used During Construction

Certain additions to utility plant include AFUDC, which represents the net cost of debt and equity funds used during construction. AFUDC is calculated using actual interest rates for debt and authorized rates for return on equity, if applicable. If short-term debt balances are less than the total balance of construction work in progress, then a composite AFUDC rate is used to represent interest on all debt funds, shown as a reduction to interest charges, and a return on equity funds, shown as other income. While cash is not immediately recognized from recording AFUDC, it is realized in future years through rate recovery resulting from the higher utility cost of service. Our composite AFUDC rates were 0.5 percent in 2011, 0.6 percent in 2010 and 1.0 percent in 2009.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with maturity dates of three months or less. At December 31, 2011, outstanding checks of approximately $3.9 million were included in accounts payable.

Revenue Recognition and Accrued Unbilled Revenues

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized upon delivery of gas commodity or service to customers. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of deliveries from meter reading dates to month end (accrued unbilled revenues). Accrued unbilled revenues are dependent upon a number of factors that require management's judgment, including total gas receipts and deliveries, customer use by billing cycle and weather factors. Accrued unbilled revenues are reversed the following month when actual billings occur. Our accrued unbilled revenues at December 31, 2011 and 2010 were $61.9 million and $64.8 million, respectively.

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From 2007 through 2010, utility net operating revenues also included the recognition of a regulatory adjustment for income taxes paid pursuant to a legislative rule (commonly referred to as SB 408) in effect for certain gas and electric utilities in Oregon. Under SB 408, we were required to automatically implement a rate refund, or a rate surcharge, to utility customers on an annual basis. The refund or surcharge amount was based on the difference between income taxes paid and income taxes authorized to be collected in customer rates. We recorded the refund, or surcharge, each quarter based on estimates of the annual amount to be recognized. On May 24, 2011, SB 408 was repealed and replaced by Senate Bill 967. SB 967 required utilities to eliminate amounts accrued under SB 408 for the 2010 and 2011 tax years, thereby denying recovery by NW Natural of the surcharge accrued for 2010, which resulted in a one-time pre-tax charge of $7.4 million in the second quarter of 2011. Pursuant to SB 967, we changed our revenue recognition policy effective January 1, 2011 and no longer recognize a regulatory adjustment for income taxes for SB 408.

Non-utility revenues are derived primarily from the gas storage business segment. At Mist, revenues are recognized upon delivery of services to customers. Revenues from our asset management partner are recognized over the life of the asset management contract for guaranteed amounts, if any, and are recognized as earned for amounts above the guaranteed amount. At Gill Ranch, firm storage services resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. Asset management revenue is recognized using a straight-line, pro rata methodology over the term of each contract and provides us with 80 percent of the pre-tax income from our independent energy marketing company. See Note 4.

Accounts Receivable and Allowance for Uncollectible Accounts

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

Inventories

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

Gas Storage inventories, which primarily represent inventories at Gill Ranch, exclude cushion gas and consist of natural gas that we received as fuel-in-kind from storage customers. Gas Storage inventories are valued at the lower of average cost or net realizable value. Cushion gas is recorded at original cost and classified as long-term assets.

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

Our utility and gas storage inventories totaled $65.6 million and $70.7 million at December 31, 2011 and 2010, respectively, and our materials and supplies inventories totaled $8.8 million and $9.7 million at December 31, 2011 and 2010, respectively.

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Gas Reserves

Our gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Transactional costs to enter into the agreement (see Note 12) and payments by NW Natural to Encana Oil & Gas (USA) Inc. (Encana) are recognized as gas reserves on the balance sheet. The current portion is calculated based on expected gas deliveries within the next fiscal year. We recognize regulatory amortization of this asset on a volumetric basis and calculate using the proven reserves and the therms extracted and sold each month. The amortization of gas reserves is recorded as an adjustment to the cost of gas.

Derivatives

In accordance with accounting for derivatives and hedges, we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. Accounting for derivatives requires that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for derivatives and hedges provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivative contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these approved contracts are deferred as regulatory assets or liabilities pursuant to regulatory accounting principles. Derivative contracts entered into for core utility customer requirements after the annual purchased gas adjustment (PGA) rate has been set are subject to the PGA incentive sharing mechanism. Effective November 1, 2008, Oregon approved a PGA sharing mechanism under which we are required to select either an 80 percent deferral or 90 percent deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20 percent or 10 percent of gas cost differences compared to PGA prices, respectively. For the PGA years in Oregon beginning November 1, 2011, 2010 and 2009, we selected a 90 percent deferral of gas cost differences. In Washington, 100 percent of our gas cost differences are deferred. See Note 13.

Our financial derivatives policy sets forth the guidelines for using selected derivative products to support prudent risk management strategies within designated parameters. Our objective for using derivatives is to decrease the volatility of gas prices, earnings and cash flows and to prevent speculative risk. The use of derivatives is permitted only after the risk exposures have been identified, are determined to exceed acceptable tolerance levels and are necessary to support normal business activities. We do not enter into derivative instruments for trading purposes and we believe that any increase in market risk created by holding derivatives should be offset by the exposures they modify.

Fair Value

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

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

use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; (g) credit spreads; (h) and other relevant economic measures.

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Revenue Taxes

We account for revenue-based taxes as a separate cost item collected from customers. Therefore, revenue taxes are accounted for as a cost of sale and presented separately on the income statement.

Income Tax Expense

NW Natural and its wholly-owned subsidiaries file consolidated federal and state income tax returns. Current income taxes are allocated based on each entity's respective taxable income or loss and tax credits as if each entity filed a separate return. We account for income taxes in accordance with accounting standards for income taxes. Accounting for income taxes requires recognition of deferred tax liabilities and assets for the future tax consequences of events that have been included in the consolidated financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse (see Note 10).

Accounting for income taxes also requires recognition of deferred income tax assets and liabilities for temporary differences where regulators prohibit deferred income tax treatment for ratemaking purposes. We have recorded a deferred tax liability equivalent of $68.5 million and $72.3 million at December 31, 2011 and 2010, respectively, to recognize future taxes payable resulting from transactions that have previously been reflected in the financial statements for these temporary differences. Regulatory assets or liabilities corresponding to such additional deferred income tax assets or liabilities may be recorded to the extent we believe they will be recoverable from or payable to customers through the ratemaking process. Pursuant to regulatory accounting principles, a corresponding regulatory asset has been recorded which represents the probable future revenue that will result from inclusion in rates charged to customers of taxes which will be paid in the future. The probable future revenue to be recorded takes into consideration the additional future taxes which will be generated by that revenue. Amounts applicable to income taxes due from customers primarily represent differences between the book and tax basis of net utility plant in service and actual removal costs incurred.

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

Subsequent Events

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

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3. Earnings Per Share

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

Thousands, except per share amounts	2011	2010	2009
Net income	$63,898	$72,667	$75,122
Average common shares outstanding - basic	26,687	26,589	26,511
Additional shares for stock-based compensation plans	57	68	65
Average common shares outstanding - diluted	26,744	26,657	26,576
Earnings per share of common stock - basic	$2.39	$2.73	$2.83
Earnings per share of common stock - diluted	$2.39	$2.73	$2.83
Additional information:			
Antidilutive shares not included in net income per diluted			
common share calculation	2,101	743	2,142

4. Segment Information

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

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale and delivery of natural gas and related services to customers in Oregon and southwest Washington. As a regulated utility, we are responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into our service territory, and re-selling the gas to customers subject to rates, terms and conditions approved by the OPUC or WUTC. Gas distribution also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers' end-use facilities for a fee, which is approved by the OPUC or WUTC. Approximately 90 percent of our customers are located in Oregon and 10 percent in Washington. On an annual basis, residential and commercial customers typically account for 50 to 60 percent of our utility's total volumes delivered and 80 to 90 percent of our utility's margin. Industrial customers account for the remaining 40 to 50 percent of volumes and 5 to 15 percent of margin. The remaining 10 percent or less of margin is derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism and other fees.

Industrial customers we serve include: pulp, paper and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation. No individual customer or industry group accounts for a significant portion of our utility revenues or margins.

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Gas Storage

Our gas storage business segment includes natural gas storage services provided to customers primarily from two underground natural gas storage facilities, our Gill Ranch gas storage facility, which commenced commercial operations in October 2010, and the non-utility portion of our Mist gas storage facility. In addition to earning revenue from customer storage contracts, we also use an independent energy marketing company to provide asset management services for utility and non-utility capacity under contractual arrangement, the results of which are included in this business segment. For the years ended December 31, 2011, 2010 and 2009, this business segment derived a majority of its revenues from asset management services and from firm and interruptible gas storage contracts.

Mist Gas Storage Facility. Earnings from non-utility assets at the Mist facility are primarily related to firm storage capacity revenues. Earnings for the gas storage segment include revenues, net of amounts shared with core utility customers, from management of utility assets at Mist and upstream capacity when not needed to serve core utility customers. In Oregon, the gas storage segment retains 80 percent of the pre-tax income from these services when the costs of the capacity have not been included in utility rates, or 33 percent of the pre-tax income when the costs have been included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for crediting back to core utility customers. We have a similar sharing mechanism in Washington for revenue derived from storage and third party asset management services.

Gill Ranch Gas Storage Facility. Gill Ranch has a joint project agreement with Pacific Gas and Electric Company (PG&E) to own the Gill Ranch underground natural gas storage facility near Fresno, California. Gill Ranch has a 75 percent undivided ownership interest in the facility, which offers storage services to the California market at market-based rates, subject to CPUC regulation including, but not limited to, service terms and conditions and tariff regulations.

Other

We have non-utility investments and other business activities which are aggregated and reported as a business segment called "other." Although in the aggregate these investments and activities are currently not material to consolidated operations, we identify and report them as a stand-alone segment based on our organizational structure and decision-making process because these business investments and activities are not specifically related to our utility or gas storage segments. This segment primarily consists of an equity method investment in a joint venture to build and operate an interstate gas transmission pipeline in Oregon (Palomar) and other pipeline assets in NNG Financial. For more on information on Palomar, see Note 12. This segment also includes some operating and non-operating revenues and expenses of the parent company that cannot be allocated to utility operations.

NNG Financial holds certain non-utility financial investments, but its assets primarily consist of an active, wholly-owned subsidiary which owns a 10 percent interest in an 18-mile interstate natural gas pipeline. NNG Financial's total assets were $1.1 million at both December 31, 2011 and 2010.

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Segment Information Summary

The following table presents summary financial information about the reportable segments for the years ended 2011, 2010 and 2009. Inter-segment transactions are insignificant.

Thousands	Utility	Gas Storage	Other	Total
2011				
Net operating revenues	$342,970	$26,354	$109	$369,433
Depreciation and amortization	63,843	6,161	-	70,004
Income from operations	135,722	9,090	33	144,845
Net income	60,527	4,101	(730)	63,898
Total assets at December 31, 2011	2,435,888	294,637	16,049	2,746,574
2010				
Net operating revenues	$346,148	$21,249	$184	$367,581
Depreciation and amortization	62,661	2,463	-	65,124
Income from operations	145,688	11,855	62	157,605
Net income	66,262	6,110	295	72,667
Total assets at December 31, 2010	2,310,388	282,945	23,283	2,616,616
2009				
Net operating revenues	$357,005	$19,738	$144	$376,887
Depreciation and amortization	61,472	1,342	-	62,814
Income from operations	142,228	16,442	46	158,716
Net income	65,960	8,923	239	75,122

5. Common Stock

Common Stock

As of December 31, 2011 and 2010, our common shares authorized were 100,000,000. As of December 31, 2011, we had reserved for issuances 155,955 shares of common stock under the Employee Stock Purchase Plan (ESPP), 293,246 shares under our Dividend Reinvestment and Direct Stock Purchase Plan and 1,159,875 shares under our Restated Stock Option Plan (Restated SOP).

Stock Repurchase Program

We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2012 to repurchase up to an aggregate of 2.8 million shares, or up to $100 million. No shares of common stock were repurchased pursuant to this program in 2011, 2010 or 2009. Since inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

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Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding for the years 2011, 2010 and 2009:

Thousands	Shares
Balance, December 31, 2008	26,501
Sales to employees under ESPP	9
Exercise of stock options under Restated SOP - net	23
Balance, December 31, 2009	26,533
Sales to employees under ESPP	24
Exercise of stock options under Restated SOP - net	111
Balance, December 31, 2010	26,668
Sales to employees under ESPP	15
Exercise of stock options under Restated SOP - net	24
Sales to shareholders under DRPP	49
Balance, December 31, 2011	26,756

6. Stock-Based Compensation

We have several stock-based compensation plans, including the Long-Term Incentive Plan (LTIP), the Restated SOP and the ESPP. These plans are designed to promote stock ownership in NW Natural by employees and officers.

Long-Term Incentive Plan

The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. An aggregate of 600,000 shares of common stock was authorized for grants under the LTIP as stock bonus, restricted stock or performance-based stock awards. Shares awarded under the LTIP may be purchased on the open market or issued as new shares.

At December 31, 2011, 337,788 shares of common stock were available for award under the LTIP, assuming that performance based grants currently outstanding are awarded at the target level. The LTIP stock awards are compensatory awards for which compensation expense is based on the fair value of stock awards, with expense being recognized over the performance and vesting period for the outstanding awards.

Performance-based Stock Awards. Since the LTIP's inception in 2001, performance-based stock awards have been granted annually based on three-year performance periods. At December 31, 2011, certain performance-based stock award measures had been achieved for the 2009-11 award period. Accordingly, participants are estimated to receive 8,428 shares of common stock and a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period. At December 31, 2010 and 2009, we awarded 8,007 and 15,900 shares of common stock, respectively, for the 2008-10 and 2007-09 award periods, plus a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period. In 2010 and 2009, we expensed $0.2 million and $0.5 million respectively for both the 2008-10 and 2007-09 performance-based stock award periods, and on a cumulative basis we accrued a total of $0.7 million and $1.5 million, respectively, related to the 2008-10 and 2007-09 performance periods.

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At December 31, 2011, the aggregate number of performance-based shares granted and outstanding at the threshold, target and maximum levels were as follows:

Performance Period	Performance Share Awards Outstanding Threshold		Target	Maximum	2011 Expense	Cumulative Expense At Dec. 31, 2011
2009-11	7,410		39,000	78,000	$353	$763
2010-12	n/a	(1)	41,500	83,000	430	718
2011-13	n/a	(1)	37,950	75,900	276	$276
Total			118,450	236,900	$1,059	

(1)The threshold requirement was modified and is no longer applicable beginning in the 2010-12 performance period.

The threshold level estimates future payout assuming the minimum award payable is achieved for each component of the formula in the LTIP. For each of these performance periods, awards will be based on total shareholder return relative to a peer group of gas distribution companies over the three-year performance period and on performance results achieved relative to specific core and non-core strategies. Compensation expense is recognized in accordance with the accounting standard for stock compensation based on performance levels achieved and an estimated fair value using a Black-Scholes or binomial model. The weighted-average grant date fair value of unvested shares at December 31, 2011 and 2010 was $25.06 and $23.10 per share, respectively. The weighted-average grant date fair value of shares vested during the year was $22.35 per share and granted during the year was $19.38 per share.

Restricted Stock Units. A new form of restricted stock awards was approved by the Board in 2011. Restricted Stock Units (RSUs) are expected to be used instead of the Restated SOP starting in February of 2012. The LTIP plan was amended to allow RSUs to be granted under the plan. RSUs are expected to include a performance based threshold and a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of the RSU.

Restated Stock Option Plan

A total of 2,400,000 shares of common stock were reserved for issuance under the Restated SOP with 580,650 available for grant as of December 31, 2011. Options under the Restated SOP may be granted only to officers and key employees designated by a committee of our Board of Directors. All options are granted at an option price equal to the closing market price on the date of grant and may be exercised for a period up to 10 years and 7 days from the date of grant. Option holders may exchange shares they have owned for at least six months, at the current market price, to purchase shares at the option price.

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

	2011		2010		2009	
Risk-free interest rate	2.0	%	2.3	%	2.0	%
Expected life (in years)	4.5		4.7		4.7	
Expected market price volatility factor	24.5	%	23.2	%	22.5	%
Expected dividend yield	3.8	%	3.8	%	3.8	%

Forfeiture rate	3.1 %	3.2 %	3.7 %
Weighted average grant date fair value	$6.73	$6.36	$5.46

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

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Information regarding the Restated SOP activity for the three years ended December 31, 2011 is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value (In millions)
Balance outstanding, Dec. 31, 2008	396,410	$38.62	$2.3
Granted	111,750	41.15	n/a
Exercised	(23,225)	30.92	0.3
Balance outstanding, Dec. 31, 2009	484,935	39.57	2.7
Granted	119,750	44.25	n/a
Exercised	(111,525)	39.01	0.9
Forfeited	(2,700)	43.00	n/a
Balance outstanding, Dec. 31, 2010	490,460	40.82	2.8
Granted	122,700	45.74	n/a
Exercised	(24,185)	33.88	0.3
Forfeited	(9,750)	44.38	n/a
Balance outstanding, Dec. 31, 2011	579,225	$42.09	$3.4
Exercisable, Dec. 31, 2011	311,951	$40.20	$2.4

In the year ended December 31, 2011, cash of $0.8 million was received for option shares exercised and a $26,000 thousand related tax benefit was realized. For the 12 months ended December 31, 2011, 2010 and 2009, the total fair value of options that vested was $0.6 million, $0.5 million and $0.4 million, respectively. The weighted average remaining life of options exercisable and outstanding at December 31, 2011 was 5.5 years and 6.8 years, respectively. As of December 31, 2011, there was $1.0 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2014.

Employee Stock Purchase Plan

The ESPP allows employees to purchase common stock at 85 percent of the closing price on the trading day immediately preceding the initial offering date, which is set annually. Each eligible employee may purchase up to $21,210 worth of stock through payroll deductions over a 12-month period.

In accordance with accounting for stock compensation, stock-based compensation expense is recognized as operations and maintenance expense or is capitalized as part of construction overhead. The following table summarizes the financial statement impact of stock-based compensation under our LTIP, Restated SOP and ESPP:

Thousands	2011	2010	2009
Operations and maintenance expense, for stock-based compensation	$1,477	$1,032	$1,434
Income tax benefit	(597)	(418)	(559)
Net stock-based compensation effect on net income	$880	$614	$875
Amounts capitalized for stock-based compensation	$261	$182	$229

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7. Cost and Fair Value Basis of Long-Term Debt

Cost of Long-Term Debt

The issuance of first mortgage debt, including secured medium-term notes (MTNs), under the Mortgage and Deed of Trust (Mortgage) is limited by eligible property, adjusted net earnings and other provisions of the Mortgage. The Mortgage constitutes a first mortgage lien on substantially all of our utility property. In addition, our Gill Ranch subsidiary senior secured notes are secured by all of the membership interests in Gill Ranch Storage, LLC as well as Gill Ranch's debt service reserve account.

The maturities on the long-term debt outstanding for each of the 12-month periods through December 31, 2016 amount to: $40 million in 2012; none in 2013; $60 million in 2014; $40 million in 2015; and $65 million in 2016.

Thousands	2011	2010	2009
Utility Medium-Term Notes:			
First Mortgage Bonds:			
4.11 % Series B due 2010	$-	$-	$10,000
7.45 % Series B due 2010	-	-	25,000
6.665% Series B due 2011	-	10,000	10,000
7.13 % Series B due 2012	40,000	40,000	40,000
8.26 % Series B due 2014	10,000	10,000	10,000
3.95 % Series B due 2014	50,000	50,000	50,000
4.70 % Series B due 2015	40,000	40,000	40,000
5.15 % Series B due 2016	25,000	25,000	25,000
7.00 % Series B due 2017	40,000	40,000	40,000
6.60 % Series B due 2018	22,000	22,000	22,000
8.31 % Series B due 2019	10,000	10,000	10,000
7.63 % Series B due 2019	20,000	20,000	20,000
5.37 % Series B due 2020	75,000	75,000	75,000
9.05 % Series A due 2021	10,000	10,000	10,000
3.176 % Series A due 2021	50,000	-	-
5.62 % Series B due 2023	40,000	40,000	40,000
7.72 % Series B due 2025	20,000	20,000	20,000
6.52 % Series B due 2025	10,000	10,000	10,000
7.05 % Series B due 2026	20,000	20,000	20,000
7.00 % Series B due 2027	20,000	20,000	20,000
6.65 % Series B due 2027	19,700	19,700	19,700
6.65 % Series B due 2028	10,000	10,000	10,000
7.74 % Series B due 2030	20,000	20,000	20,000
7.85 % Series B due 2030	10,000	10,000	10,000
5.82 % Series B due 2032	30,000	30,000	30,000
5.66 % Series B due 2033	40,000	40,000	40,000
5.25 % Series B due 2035	10,000	10,000	10,000
	641,700	601,700	636,700
Subsidiary Senior Secured Notes:			
Gill Ranch Notes due 2016(1)	40,000	-	-
	681,700	601,700	636,700
Less current maturities of long-term debt	40,000	10,000	35,000
Total long-term debt	$641,700	$591,700	$601,700

(1) In November 2011, Gill Ranch issued senior secured notes consisting of $20 million of fixed rate notes with an interest rate of 7.75 percent and $20 million of variable interest rate notes with an interest rate of LIBOR plus 5.50, or a minimum of 7.00 percent. Currently, the variable interest rate is 7.00 percent.

Utility Medium-Term Notes

In March 2009, the utility issued $75 million of 5.37 percent secured MTNs due February 1, 2020, and in July 2009 issued another $50 million of 3.95 percent secured MTNs due July 15, 2014. The utility also issued $50 million of MTNs in September 2011 with an interest rate of 3.176 percent and a maturity date of September 15, 2021.

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Subsidiary Senior Secured Notes

In November 2011, Gill Ranch issued $40 million of subsidiary senior secured notes with an interest rate of 7.75 percent on the fixed portion and a 7.00 percent interest rate currently on the variable portion. The notes are secured by all of the membership interests in Gill Ranch Storage, LLC, and are nonrecourse notes to NW Natural. The maturity date of these notes is November 30, 2016.

Under the note agreements, Gill Ranch is subject to certain covenants and restrictions, including but not limited to, a financial covenant that requires Gill Ranch to maintain minimum adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) at various levels over the term of the notes. The minimum adjusted EBITDA increases incrementally over the first few years, reaching its highest level in the 12-month period beginning April 1, 2015. Under the note agreements, Gill Ranch is also subject to a debt service reserve requirement of 10 percent of the outstanding principal amount, initially $4 million, certain prepayment penalties, restrictions on dividends out of Gill Ranch unless certain earnings ratios are met, and restrictions on incurrence of additional debt.

Fair Value of Long-Term Debt

The following table provides an estimate of the fair value of our long-term debt including current maturities of long-term debt, using market prices in effect on the valuation date. Because our debt outstanding does not trade in active markets, we used interest rates for outstanding debt issues that actively trade and have similar characteristics such as size, credit ratings, financial terms and remaining maturities to estimate fair value for our long-term debt issues.

	December 31,	
Thousands	2011	2010
Carrying amount	$681,700	$601,700
Estimated fair value	$808,724	$690,126

8. Short-term Debt and Credit Facilities

Our primary source of short-term funds is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans to meet seasonal working capital requirements, short-term debt is used temporarily to fund capital requirements. Commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by one or more committed credit facilities. At December 31, 2011 and 2010, the amounts and average interest rates of commercial paper debt outstanding were $141.6 million at 0.3 percent and $257.4 million at 0.4 percent, respectively. There were no bank loans outstanding at December 31, 2011 or 2010.

At NW Natural, we have a multi-year $250 million syndicated credit agreement, pursuant to which we may extend commitments for additional one-year periods subject to lender approval. We extended commitments under this syndicated agreement to May 31, 2013. The syndicated agreement allows us to request increases in the total commitment amount from time to time, up to a maximum amount of $400 million, and to replace any lenders who decline to extend the terms of the agreement. The syndicated agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. Any principal and unpaid interest owed on borrowings under the syndicated agreement are due and payable on or before the expiration date. There were no outstanding balances under the syndicated credit agreement and no letters of credit issued or outstanding at December 31, 2011 and 2010.

The syndicated credit agreement requires that we maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service, Inc. (Moody's) and notify the lenders of any change in our senior unsecured debt ratings by such rating agencies. A change in our debt ratings is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit facility. However, interest rates on any loans outstanding under the credit facility are tied to debt ratings, which would increase or decrease the cost of any loans under the credit facility when ratings are changed. There were no changes in our credit ratings during 2011.

The syndicated credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2011 and 2010.

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9. Pension and Other Postretirement Benefits

We maintain two qualified non-contributory defined benefit pension plans covering a majority of our regular NW Natural employees with more than one year of service, several non-qualified supplemental pension plans for eligible executive officers and certain key employees and other postretirement employee benefit plans. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. Only the two qualified defined benefit pension plans and Retirement K Savings Plan have plan assets, which are held in a qualified trust to fund retirement benefits. Effective January 1, 2007 and 2010, the qualified defined benefit retirement plans and postretirement benefits for non-union employees and for union employees, respectively, were closed to new participants. These plans were not available to employees of our NW Natural subsidiaries. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit. Also, effective January 1, 2007, the postretirement Welfare Benefit Plan for Non-Bargaining Unit Employees was closed to new participants after December 31, 2006.

The following table provides a reconciliation of the changes in benefit obligations and fair value of plan assets, as applicable, for the pension and other postretirement benefit plans, excluding the Retirement K Savings Plan, for the years ended December 31, 2011, 2010, and 2009, and a summary of the funded status and amounts recognized in the consolidated balance sheets using measurement dates as of December 31, 2011, 2010 and 2009:

	Postretirement Benefit Plans					
	Pension Benefits			Other Benefits		
Thousands	2011	2010	2009	2011	2010	2009
Reconciliation of change in benefit obligation:						
Obligation at January 1	$339,338	$307,991	$281,127	$27,676	$24,741	$23,863
Service cost	7,122	6,688	6,402	614	588	522
Interest cost	18,134	18,029	17,948	1,404	1,436	1,568
Net actuarial (gain) or loss	44,802	25,275	23,584	2,225	2,387	216
Benefits paid	(18,269)	(18,645)	(17,149)	(1,870)	(1,476)	(1,428)
Plan amendments	-	-	(3,921)	-	-	-
Obligation at December 31	$391,127	$339,338	$307,991	$30,049	$27,676	$24,741
Reconciliation of change in plan assets:						
Fair value of plan assets at January 1	$219,014	$201,312	$163,115	$-	$-	$-
Actual return on plan assets	(6,684)	24,651	28,641	-	-	-
Employer contributions	21,909	11,696	26,705	1,870	1,476	1,428
Benefits paid	(18,269)	(18,645)	(17,149)	(1,870)	(1,476)	(1,428)
Fair value of plan assets at December 31	$215,970	$219,014	$201,312	$-	$-	$-
Funded status at December 31	$(175,157)	$(120,324)	$(106,679)	$(30,049)	$(27,676)	$(24,741)

Our qualified defined benefit pension plans had an aggregate projected benefit obligation of $362.9 million, $314.5 million and $285.2 million at December 31, 2011, 2010, and 2009, respectively, and the fair value of plan assets was

$216.0 million, $219.0 million and $201.3 million, respectively. Changes in certain pension assumptions impact our projected benefit obligations. Benefit obligations at December 31, 2011 increased $40.3 million due to decreases in our discount rate assumptions and increased by $0.9 million due to changes in other assumptions. The projected benefit obligations at December 31, 2010 increased $17.9 million over the prior year due to decreases in our discount rate assumptions and increased by $6.5 million due to changes in other assumptions.

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The following table provides amounts amortized from accumulated other comprehensive income (AOCI) or regulatory assets to net periodic benefit cost during 2011, 2010, and 2009:

	Regulatory Asset Amortization						AOCI Amortization		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
Thousands	2011	2010	2009	2011	2010	2009	2011	2010	2009
Net periodic benefit costs:									
Actuarial loss	$10,731	$6,740	$6,189	$289	$131	$17	$854	$707	$449
Prior service cost	230	230	1,260	197	197	197	122	(43)	(37)
Transition obligation	-	-	-	411	411	411	-	-	-
Total	$10,961	$6,970	$7,449	$897	$739	$625	$976	$664	$412

In 2012, an estimated $15.5 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $14.7 million of actuarial losses, $0.4 million of prior service costs and $0.4 million of transition obligations, and $1.0 million will be amortized from AOCI to earnings related to actuarial losses.

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

The assumption for expected long-term rate of return on plan assets was developed as a weighted average of the expected earnings for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plans' assets are invested and the target asset allocation for plan assets.

Our investment strategy and policies for the qualified pension plan assets held in the Retirement Trust Fund were approved by our retirement committee, which is composed of senior management employees with the assistance of an investment consultant. The policies set forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity and portfolio risk. All investments are expected to satisfy the requirements of the rule of prudent investments as set forth under the Employee Retirement Income Security Act of 1974. The approved asset classes include cash and short-term investments, fixed income, common stock and convertible securities, absolute and real return strategies, real estate and investments in our common stock. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Investment re-balancing takes place periodically as needed, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target ranges. Our expected long-term rate of return is based upon historical index returns by asset class, adjusted by a factor based on our historical return experience, diversified asset allocation and active portfolio management by professional investment managers. The Retirement Trust Fund is not currently invested in any NW Natural securities.

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The following is our pension plan asset target allocation at December 31, 2011:

Asset Category	Target Allocation	
U.S. large cap equity	15.0	%
U.S. small/mid cap equity	10.0	%
Non-U.S. equity	14.5	%
Emerging markets equity	3.5	%
Long government/credit	24.0	%
High yield	5.0	%
Emerging market debt	5.0	%
Real estate funds	5.8	%
Absolute return strategy	12.0	%
Real return strategy	5.2	%

Our non-qualified supplemental defined benefit pension benefit obligations were $28.2 million, $24.9 million and $22.8 million at December 31, 2011, 2010 and 2009, respectively. These plans are not subject to regulatory deferral and the changes in actuarial gains and losses, prior service costs and transition assets or obligations are recognized in AOCI under common stock equity, net of tax, until they are amortized as a component of net periodic benefit cost. Although these are unfunded plans with no plan assets due to their nature as non-qualified plans, we indirectly fund a portion of our obligations with company- and trust-owned life insurance.

Our plans for providing postretirement benefits other than pensions also are unfunded plans, but are subject to regulatory deferral. The gains and losses, prior service costs and transition assets or obligations for these plans were recognized as a regulatory asset.

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

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The following tables provide the components of net periodic benefit cost for the qualified and non-qualified pension and other postretirement benefit plans for the years ended December 31, 2011, 2010 and 2009 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
Thousands	2011	2010	2009	2011	2010	2009
Service cost	$7,122	$6,688	$6,402	$614	$588	$522
Interest cost	18,134	18,029	17,948	1,404	1,436	1,568
Expected return on plan assets	(17,867)	(18,207)	(15,696)	-	-	-
Amortization of transition obligations	-	-	-	411	411	411
Amortization of prior service costs	352	187	1,223	197	197	197
Amortization of net actuarial loss	11,584	7,447	6,810	289	131	-
Net periodic benefit cost	19,325	14,144	16,687	2,915	2,763	2,698
Amount allocated to construction	(4,905)	(3,729)	(4,636)	(878)	(904)	(858)
Amount deferred to regulatory balancing account	(6,008)	-	-	-	-	-
Net amount charged to expense	$8,412	$10,415	$12,051	$2,037	$1,859	$1,840

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	2011	2010	2009
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	5.49%	6.01%	6.60%	5.16%	5.78%	7.12%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	8.25%	8.25%	8.25%	n/a	n/a	n/a
Assumptions for funded status:						
Weighted-average discount rate	4.51%	5.49%	6.01%	4.33%	5.16%	5.78%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	8.00%	8.25%	8.25%	n/a	n/a	n/a

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2011 were 8.0 percent for medical and 10.0 percent for prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 5.0 percent by 2021.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

Thousands	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	$67	$(60)
Effect on the accumulated postretirement benefit obligation	$678	$(613)

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

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The following table provides information regarding employer contributions and benefit payments for the two qualified pension plans, non-qualified pension plans and other postretirement benefit plans for the years ended December 31, 2011 and 2010, and estimated future contributions and payments:

Thousands	Pension Benefits	Other Benefits
Employer Contributions		
2010	$12,088	$1,476
2011	22,325	1,870
2012 (estimated)	30,109	2,056
Benefit Payments		
2009	17,149	1,428
2010	18,645	1,476
2011	18,269	1,870
Estimated Future Payments		
2012	19,374	2,056
2013	19,620	2,083
2014	20,107	2,138
2015	20,640	2,149
2016	21,284	2,198
2017-2021	122,680	11,298

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. The Pension Protection Act of 2006 (the Act) established new funding requirements for defined benefit plans. The Act establishes a 100 percent funding target over seven years for plan years beginning after December 31, 2008. Our qualified defined benefit pension plans are currently underfunded by $146.9 million at December 31, 2011, and we expect to make contributions during 2012 of approximately $28 million.

The Retirement K Savings Plan provided to our employees is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Our contributions to this plan totaled $2.4 million 2011 and $2.1 million in 2010 and 2009. The Retirement K Savings Plan includes an Employee Stock Ownership Plan.

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

In addition to the company-sponsored defined benefit plans referred to above, we contribute to a multiemployer pension plan for our bargaining unit employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan) in accordance with our collective bargaining agreement. The employer identification number of the plan is 94-6076144. The cost of this plan is in addition to pension expense in the table above. The Western States Plan is managed by a board of trustees that includes equal representation from participating employers and labor unions. Contribution rates are established by collective bargaining agreements, and benefit levels are set by the board of trustees based on the advice of an independent actuary regarding the level of benefits that agreed-upon contributions are expected to support. The Western States Plan has reported an accumulated funding deficit for the current plan year and remains in critical status. A plan is considered to be in critical status if its funded status is 65 percent or less. Federal law requires pension plans in critical status to adopt a rehabilitation plan designed to restore the financial health of the plan. Rehabilitation plans may specify benefit reductions, contribution surcharges, or a combination of the two. The Western States Plan trustees adopted a rehabilitation plan that reduced benefit accrual rates and adjustable benefits for active employee participants and increased future employer contribution rates. These changes are expected to improve the funded status of the plan. Our contributions to the Western States Plan amounted to $0.4 million in 2011, 2010 and 2009 which is greater than 5 percent of the total contributions to the plan by all participants.

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This amount includes the 10 percent contribution surcharge. Contribution surcharges above the current 10 percent rate will be assessed to employer participants, but these higher surcharges will not go into effect for NW Natural until its next collective bargaining agreement, which is expected to be no earlier than June 1, 2014. Under the terms of our current collective bargaining agreement, which became effective in July 2009, we can withdraw from the Western States Plan at any time. However, if we withdraw and the plan is underfunded, we could be assessed a withdrawal liability. In accordance with accounting rules for multiemployer plans, we have not currently recognized these potential withdrawal liabilities on the balance sheet. Currently, we have no intent to withdraw from the plan, so we have not recorded a withdrawal liability.

Fair Value

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

U.S. large cap equity: These are level 1 assets valued at the closing price reported on the active market on which the individual security is traded. This asset class includes investments primarily in U.S. common stocks.

U.S. small/mid cap equity: These are level 2 assets valued based on information provided by the plan's investment custodians. The financial statements of the commingled fund are audited annually by independent accountants. Values for such funds are stated at estimated fair values, which have been determined based on the unit values of the funds. Unit values are determined by the bank sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation date. This asset class includes investments primarily in U.S. common stocks.

Non-U.S. equity: These are level 1 and 2 assets. Level 1 assets are valued at the closing price reported on the active market on which the individual security is traded. Level 2 assets are valued based on information provided by the plan's investment custodians. The financial statements of the commingled fund are audited annually by independent accountants. Values for such funds are stated at estimated fair values, which have been determined based on the unit values of the funds. Unit values are determined by the bank sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation date. This asset class includes investments primarily in foreign equity common stocks.

Emerging market equity: These are level 1 assets valued at the net asset value of the shares held by the plan at the valuation date. This asset class includes investments primarily in common stocks in emerging markets.

Fixed income: These are level 1 assets valued at the net asset value of the shares held by the plan at the valuation date. This asset class includes investments primarily in investment grade debt and fixed income securities.

Long Government/Credit: These are level 2 assets whose values are determined by closing values if available and by matrix pricing for illiquid securities. This asset class includes long duration fixed income investments primarily in U.S. treasuries, U.S. government agencies, municipal securities, mortgage-backed securities, asset-backed securities, as well as U.S. and international investment-grade corporate bonds.

Real estate funds: These are level 3 assets valued based on the interest held by the plan, for which fair values of the underlying investments are subject to appraisal as directed by the funds' management. This asset class includes a real estate fund that invests directly in real estate. The underlying properties held in the funds are appraised utilizing the following approaches: the cost approach (the current cost of replacing the real estate less deterioration and functional and economic obsolescence); the income approach (the ability of the underlying properties to generate net rental income); and the comparable sales approach (recent sales of comparable real estate in the same market). The plan's ability to redeem these investments is subject to certain restrictions and cash availability.

Absolute return strategy: These are level 2 assets valued based on information provided by the plan's investment custodians. The financial statements of the partnerships are audited annually by independent accountants, with the value of the underlying investments based on the estimated fair value of the various holdings in the portfolio as reported in the financial statements at net asset value. This asset class includes a hedge fund. Our investment normally provides for a quarterly distribution subject to 95 days advance notice of withdrawal. Currently there are no restrictions on withdrawal requests, and as of December 31, 2011 we have not submitted a withdrawal request.

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Real return strategy: These are level 1 assets valued at the net asset value of the shares held by the plan at the valuation date. This asset class includes an investment in a broad range of assets and strategies primarily including fixed income and equity securities, along with commodities.

Cash and cash equivalents: These are level 2 assets valued at the net asset value of the shares held by the plan at the valuation date. This asset class primarily includes a money market mutual fund.

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

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

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The following table presents the fair value of plan assets, including outstanding receivables and liabilities, of the Retirement Trust Fund as of December 31, 2011 and 2010:

	December 31, 2011			
Investments, in thousands	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$36,236	$-	$-	$36,236
U.S. small/mid cap equity	-	27,310	-	27,310
Non-U.S. equity	22,158	11,587	-	33,745
Emerging markets equity	10,208	-	-	10,208
Fixed income	19,121	-	-	19,121
Long government/credit	-	18,897	-	18,897
Real estate funds	-	-	15,317	15,317
Absolute return strategy	-	30,475	-	30,475
Real return strategy	15,475	-	-	15,475
Cash and cash equivalents	-	9,290	-	9,290
Total investments	$103,198	$97,559	$15,317	$216,074

	December 31, 2010			
Investments, in thousands	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$37,231	$-	$-	$37,231
U.S. small/mid cap equity	-	27,864	-	27,864
Non-U.S. equity	24,630	14,549	-	39,179
Emerging markets equity	11,476	-	-	11,476
Fixed income	36,429	-	-	36,429
Real estate funds	-	-	14,721	14,721
Absolute return strategy	-	32,378	-	32,378
Real return strategy	15,452	-	-	15,452
Cash and cash equivalents	-	3,629	-	3,629
Total investments	$125,218	$78,420	$14,721	$218,359

	December 31,	
Receivables	2011	2010
Accrued interest and dividend income	$414	$249
Due from broker for securities sold	321	448
Total receivables	$735	$697
Liabilities		
Due to broker for securities purchased	$839	$42
Total investment in retirement trust	$215,970	$219,014

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Level 3 Investments

The following table presents the beginning balance, activity and ending balance of Level 3 investments that have their fair values established using significant unobservable inputs as of December 31, 2011:

Thousands	Level 3 Assets Real estate Funds
January 1, 2011 balance	$14,721
Total gains or (losses):	
Included in earnings (or changes in net assets)	596
December 31, 2011 balance	$15,317

10. Income Tax

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

Thousands, except percentages	2011	2010	2009
Income taxes at federal statutory rate	$37,550	$42,745	$42,627
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,945	5,803	5,568
Amortization of investment and energy tax credits	(442)	(525)	(593)
Differences required to be flowed-through by regulatory commissions	1,647	1,647	(116)
Gains on company and trust-owned life insurance	(786)	(715)	(1,195)
Other - net	468	507	380
Total provision for income taxes	$43,382	$49,462	$46,671
Effective tax rate	40.4%	40.5%	38.3%

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

Thousands	2011	2010	2009
Current			
Federal	$130	$(28,592)	$6,221
State	(929)	1,441	2,300
	(799)	(27,151)	8,521
Deferred			
Federal	35,481	69,159	31,937
State	8,700	7,454	6,213
	44,181	76,613	38,150
Total provision for income taxes	$43,382	$49,462	$46,671
Total income taxes paid	$1,756	$22,600	$10,000

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

Thousands	2011	2010	2009
Regulated utility:			
Current	$(4,646)	$(1,464)	$871
Deferred	50,152	47,741	40,829
Deferred investment and energy tax credits	(422)	(525)	(593)
	45,084	45,752	41,107
Non-utility business segments:			
Current	3,846	(25,687)	7,650
Deferred	(5,548)	29,397	(2,086)
	(1,702)	3,710	5,564
Total provision for income taxes	$43,382	$49,462	$46,671

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

Thousands	2011	2010
Deferred tax liabilities:		
Plant and property	$292,235	$255,471
Regulatory adjustment for income taxes paid	2,106	5,272
Regulatory income tax assets	65,755	68,822
Regulatory liabilities	35,638	23,159
Non-regulated deferred tax liabilities	43,373	34,544
Total	$439,107	$387,268
Deferred tax assets:		
Regulatory assets	(4,727)	(1,402)
Unfunded pension and postretirement obligations	(5,119)	(4,342)
Non-regulated deferred tax assets	(1,161)	(772)
Alternative minimum tax credit carryforward	(1,626)	(1,702)
Loss and credit carryforwards	(14,255)	(7,071)
Total	(26,888)	(15,289)
Deferred income tax liabilities - net	412,219	371,979
Deferred investment tax credits	990	1,430
Deferred income taxes and investment tax credits	$413,209	$373,409

We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2011.

We calculate our deferred tax assets and liabilities according to accounting guidance on income taxes, whereby deferred income taxes are generally determined based on the difference between the financial statement and tax bases of assets and liabilities using enacted tax rates in effect in the years in which the differences are expected to reverse. Deferred tax provisions are not recorded in the income statement for certain temporary differences where regulators require that we flow through deferred income tax benefits or expenses in the utility ratemaking process.

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In September 2010, Congress passed the Unemployment Insurance, Reauthorization and Job Creation Act of 2010 (the Act) and the legislation was signed into law by President Obama. The Act extended for one year the temporary bonus depreciation rules first enacted in the Economic Stimulus Act of 2008 and subsequently renewed in the American Recovery and Reinvestment Act of 2009. Under the bonus depreciation provision, an additional first-year tax deduction was allowed for depreciation equal to 50 percent of the adjusted basis of qualified property through September 8, 2010, in the year the property was placed in service, with the remaining percentage recovered under the normal depreciation rules. In addition, on December 17, 2010, President Barack Obama signed into law the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act), which allows 100 percent bonus depreciation for qualified property placed in service between September 9, 2010 through December 31, 2011. It also extended the 50% bonus depreciation deduction to qualifying property placed in service through 2012.

In 2011 the Company received a tax refund of $14.4 million for tax year 2010. In addition, the company carried back a portion of its 2010 net operating loss to tax year 2009 and received a refund of $22.3 million. In 2011 we filed an amended federal income tax return for 2009, primarily to report a deduction for repairs expense consistent with a change in accounting method approved by the IRS and in conformity with the deduction allowed by the IRS in its examination of years 2006-2008. The Company then amended its net operating loss carryback to tax year 2009. The result of the amended federal tax return for tax year 2009 and the amended net operating loss carryback is a federal income tax refund receivable of $3.5 million at December 31, 2011. The company estimates that it has a consolidated net operating loss carryforward to 2012 of $33.7 million. The net operating loss carryforward will be carried forward to reduce our current tax liability in future years. We anticipate that we will be able to utilize the entire net operating loss carryforward before its expiration in twenty years.

For the year ended December 31, 2010, we reported taxable income for Oregon purposes due to lack of federal-state conformity with respect to the accelerated depreciation effects cited above. The Company recorded a current receivable of $3.5 million to reflect the excess of payments applied to year 2010 over the amount owed. The Company received this refund in the first quarter of 2012. As of January 1, 2011, Oregon conformed to federal rules including bonus depreciation. As a result, we anticipate generating an NOL for state purposes in 2011. Oregon does not allow NOL carrybacks, but allows NOLs to be carried forward for fifteen years. We expect to fully utilize the estimated NOL generated in 2011.

Uncertain tax positions are accounted for in accordance with accounting standards that require management’s assessment of the expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, we would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company’s consolidated balance sheet. As of December 31, 2011, we had no uncertain tax positions.

The IRS completed its examination of the 2006 through 2008 tax years in 2011. The examination resulted in payments of $1.5 million of tax and $0.2 million of interest. The Oregon Department of Revenue (ODOR) completed its field examination of our 2006 through 2009 consolidated Oregon income tax returns and issued preliminary assessments. If sustained by the ODOR, these assessments would result in an additional state tax liability of approximately $0.8 million, including interest and penalties. The Company is engaged in discussions with ODOR to resolve these issues; however, uncertainty exists with respect to the outcome of the audit as a result of information not yet fully considered by the ODOR. Resolution is expected to be reached within the next 12 months, and we have determined that it is more-likely-than-not that we will prevail on these issues. As such, no amounts have been recorded in our financial statements as of December 31, 2011 related to this matter.

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

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11. Property, Plant and Equipment

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

Thousands	2011	2010
Utility plant in service	$2,323,467	$2,247,952
Utility construction work in progress	36,051	29,324
Less accumulated depreciation	749,603	710,214
Utility plant-net	1,609,915	1,567,062
Non-utility plant in service	293,205	290,038
Non-utility construction work in progress	8,379	9,088
Less accumulated depreciation	17,623	12,025
Non-utility plant-net	283,961	287,101
Total property plant and equipment	$1,893,876	$1,854,163

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

Accumulated depreciation does not include the accumulated provision for asset removal costs of $267.4 million and $252.9 million at December 31, 2011 and 2010, respectively. These accrued asset removal costs are reflected on the balance sheets as regulatory liabilities (see Note 2, "Plant, Property and Accrued Asset Removal Costs").

12. Gas Reserves and Other Investments

Our gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Other investments include financial investments in life insurance policies, which are accounted for at fair value, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity or cost methods. The following table summarizes our other investments at December 31:

Thousands	2011	2010
Investments in life insurance policies	$51,911	$51,090
Investments in gas pipeline joint ventures	14,340	15,742
Other	2,012	2,262
Total other investments	$68,263	$69,094

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Gas Reserves

We entered into an agreement with 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. Under the agreement, we expect to invest approximately $45 million to $55 million per year for five years, and our total investment is expected to be approximately $250 million.

Upon reviewing the transaction, the OPUC determined that our costs under the agreement will be recovered on an ongoing basis through its annual PGA mechanism, including the regulatory deferral and incentive sharing process for the commodity cost of gas. Annually, a forecast will be established for the amounts related to costs and volumes expected, and any variances between forecasted and actual will be subject to the PGA incentive sharing in Oregon, up to a maximum variance of $10 million of which 10 percent (or $1 million maximum) would be recognized in current income. Variances in excess of $10 million, both negative and positive, will be deferred and passed through to customers in future rates at 100 percent. As part of the decision by the OPUC, we agreed to file a general rate case in Oregon no later than December 31, 2011.

Encana began drilling in May 2011 under the agreements referred to above, and we are currently receiving gas from our interests in a section of the gas field. In 2011, volumes from gas reserves were less than one percent of our total gas purchases. Our net investment at December 31, 2011 is $36.3 million, including deferred tax liabilities totaling $15.6 million.

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

Palomar

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 NWN Energy and 50 percent by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. PGH is a development stage variable interest entity.

Variable Interest Entity (VIE) Analysis. As of December 31, 2011, we updated our VIE analysis and reconfirmed that we are not the primary beneficiary of PGH's activities as defined by the authoritative guidance related to consolidations due to the fact that we have a 50 percent share and there are no stipulations that allow disproportionate influence over the entity. Therefore, we account for our investment in PGH and the Palomar project under the equity method, which is included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50 percent owner.

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

In 2011, our investment in PGH was reviewed for impairment when Palomar withdrew its original application with the FERC for a proposed natural gas pipeline in Oregon. At the same time, Palomar informed FERC that it intended to re-file an application to reflect changes in the project scope, which was expected to eliminate the western portion of the proposed pipeline and align the revised project with the region's current and future gas infrastructure needs. Palomar is working with customers in the Pacific Northwest to further understand their gas transportation needs and determine the commercial support for a revised pipeline proposal. We expect to file a new FERC certificate application to reflect a revised scope based on regional needs.

The evaluation of assets related to the west portion of the Palomar pipeline determined that these costs were impaired, and as a result we recorded a pre-tax charge of $0.3 million for our share of the project. An evaluation of the assets related to the east portion was also performed in 2011, and a charge of $1.0 million was recorded. The east segment charge was related to costs that would potentially be outdated and, if so, would need to be redone for the refiled application. Our remaining investment balance in Palomar was $13.5 million at December 31, 2011, which consists of costs related to the east segment. We also determined that our remaining equity investment was not impaired because the fair value of expected cash flows from planned development of the eastern portion of the pipeline project exceeds our equity investment. However, if we learn later that the project is not viable or will not go forward, then we could be required to recognize a maximum charge of up to approximately $13.2 million based on the current amount of our equity investment net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as required.

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Investment in Life Insurance Policies

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

13. Derivative Instruments

We enter into swap, option and combinations of option contracts for the purpose of hedging natural gas. We primarily use these derivative financial instruments to manage commodity prices related to our natural gas purchase requirements. A small portion of our derivative hedging strategy involves foreign currency exchange transactions related to purchases of natural gas from Canadian suppliers.

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of core utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to these physical gas supply contracts. Derivatives entered into prudently for future gas years prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate is set for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for either an 80 or a 90 percent deferral of any gains and losses as regulatory assets or liabilities, with the remaining 10 or 20 percent recognized in current income. All of our commodity hedging for the 2011-12 gas year was completed prior to the start of the gas year, and these hedge prices were included in our PGA filing.

Certain natural gas purchases from Canadian suppliers are payable in Canadian dollars, including both commodity and demand charges, which expose us to adverse changes in foreign currency rates. Foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for our commodity and commodity-related demand charges paid in Canadian dollars. Foreign currency contracts for commodity costs are purchased on a month-to-month basis because the Canadian cost is priced at the average noon-day exchange rate for each month. Foreign currency contracts for demand costs have terms ranging up to 12 months. The gains and losses on the shorter-term currency contracts for commodity costs are recognized immediately in cost of gas. The gains and losses on the currency contracts for demand charges are not recognized in current income because they are subject to a regulatory deferral tariff and, as such, are recorded as a regulatory asset or liability. The mark-to-market adjustment at December 31, 2011 was an unrealized loss of $0.2 million. This unrealized gain is subject to regulatory deferral and, as such, was recorded as a derivative instrument, which is offset by recording a corresponding amount to a regulatory liability account.

Derivative hedge contracts are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2011, all of our derivatives were effective economic hedges and either qualified or were expected to qualify for regulatory deferral or hedge accounting treatment. The effectiveness test applied to financial derivatives is dependent on the type of derivative and its use. We use the hypothetical derivative method under accounting standards for derivatives and hedging to determine the hedge effectiveness for our interest rate swaps and the dollar offset method for other derivative contracts under accounting standards for derivatives and hedging. All derivatives were effective as of December 31, 2011.

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The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments for the year ended December 31, 2011 and 2010. All of our currently outstanding derivative instruments are related to regulated utility operations as illustrated by the derivative gains and losses being deferred to balance sheet accounts in accordance with regulatory accounting standards.

	2011		2010	
Thousands	Natural gas commodity(1)	Foreign exchange (2)	Natural gas commodity(1)	Foreign exchange (2)
Cost of sales	$(60,799)	$-	$(52,677)	$-
Other comprehensive income (loss)	-	(201)	-	91
Less:				
Amounts deferred to regulatory accounts on balance sheet	60,799	201	52,677	(91)
Total impact on earnings	$-	$-	$-	$-

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

No collateral was posted with or by our counterparties as of December 31, 2011 or 2010. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and diversification, we have not been subject to collateral calls in 2010 or 2011. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current contracts outstanding, which reflect unrealized losses of $63.5 million at December 31, 2011, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various downgrade credit rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
Thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ -	$-	$2,013	$9,585	$45,869
Without Adequate Assurance Calls	$ -	$-	$851	$5,923	$37,206

As of December 31, 2011 and 2010, we realized net losses of $56.5 million and $61.0 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts.

We are exposed to derivative credit risk primarily through securing pay-fixed natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases on behalf of customers. We utilize master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. In certain cases we require guarantees or letters of credit from counterparties in order for them to meet our minimum credit requirement standards.

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

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions and market news. We utilize a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. We use the results of the model to establish earnings-at-risk trading limits. Our credit risk for all outstanding derivatives at December 31, 2011 currently does not extend beyond October 2013.

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

Fair Value

In accordance with fair value accounting, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. Our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at December 31, 2011. As of December 31, 2011 and 2010, the fair value was a liability of $61.0 million and $52.6 million, respectively, using significant other observable, or level 2, inputs. We have used no level 3 inputs in our derivative valuations. We also did not have any transfers between level 1 or level 2 during the years ended December 31, 2011 and 2010.

14. Leases

We lease land, buildings and equipment under agreements that expire in various years through 2095. Rental expense under operating leases was $5.4 million, $5.1 million and $5.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. The table below reflects the future minimum lease payments due under non-cancelable leases at December 31, 2011. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, vehicles and computer equipment.

Thousands	2012	2013	2014	2015	2016	Later years	Total
Operating leases	$4,929	$4,841	$5,078	$5,042	$5,018	$24,659	$49,567
Capital leases	443	313	118	23	-	-	897
Minimum lease payments	$5,372	$5,154	$5,196	$5,065	$5,018	$24,659	$50,464

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15. Commitments and Contingencies

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

We have signed agreements providing for the reservation of firm pipeline capacity under which we are required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies. In addition, we have entered into long-term sale agreements to release firm pipeline capacity. We also enter into short-term and long-term gas purchase agreements. The aggregate amounts of these agreements were as follows at December 31, 2011:

Thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2012	$98,534	$91,027	$3,464
2013	18,331	87,983	-
2014	15,290	82,898	-
2015	5,651	72,316	-
2016	-	61,358	-
Thereafter	-	287,541	-
Total	137,806	683,123	3,464
Less: Amount representing interest	682	99,252	2
Total at present value	$137,124	$583,871	$3,462

Our total payments for fixed charges under capacity purchase agreements in 2011, 2010 and 2009 were $94.2 million, $91.4 million and $84.6 million, respectively. Included in the amounts were reductions for capacity release sales of $3.1 million for 2011 and $4.2 million for 2010 and 2009. In addition, per-unit charges are required to be paid based on the actual quantities shipped under the agreements. In certain take-or-pay purchase commitments, annual deficiencies may be offset by prepayments subject to recovery over a longer term if future purchases exceed the minimum annual requirements.

Environmental Matters

We own, or previously owned, properties that may require environmental remediation or action. We recognize an environmental liability when it is probable the liability exists and the amount is reasonably estimable. We estimate the duration and extent of our remediation obligations based upon reports of outside consultants; internal analyses of clean-up costs and ongoing monitoring costs; communications with regulatory agencies; and changes in environmental law. If we were to determine that our estimates of the duration or extent of our environmental obligations were no longer accurate, we would adjust our environmental liabilities accordingly in the period that such determination is made. Estimated future expenditures for environmental remediation are not discounted to their present value. Accrued environmental liabilities are not reduced by potential insurance reimbursements. We continue to study and evaluate the extent of our potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss which could be material. In those cases we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated.

We estimate the range of loss for environmental liabilities using current technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is an estimate within this range of possible losses that is more likely than other cost estimates, we record the liability at the lower end of this range. It is likely that changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to uncertainty concerning our responsibility, the complexity of environmental laws and regulations and the selection of potentially compliant remediation alternatives. The status of each of the sites currently under investigation is provided below.

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We regularly review our environmental liability for each site where we may be exposed to remediation responsibilities. The costs of environmental remediation are difficult to estimate. A number of steps are involved in each environmental remediation effort, including site investigations, remediation, operations and maintenance, monitoring and site closure. Each of these steps may, over time, involve a number of alternative actions, each of which can change the course and scope of the effort. Many of these steps are dependent upon the approval and direction of federal and state environmental regulators. The policies, determinations and directions of the regulators may develop and change over time and different regulators may take different positions on the various steps, creating further uncertainty as to the timing and scope of remediation activities. In certain cases, in addition to us, there are a number of other potentially responsible parties, each of which, in proceedings and negotiations with other potentially responsible parties and regulators, may influence the course and scope of the remediation effort. The allocation of liabilities among the potentially responsible parties is often subject to dispute and can be highly uncertain. The events giving rise to environmental liabilities often occurred many decades ago, which complicates the determination of allocating liabilities among potentially responsible parties. Site investigations and remediation efforts often develop slowly over many years. 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. These disputes could lead to adversarial administrative proceedings or litigation, with uncertain outcomes.

Gasco site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (Gasco site). The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality's (ODEQ) Voluntary Clean-Up Program. In June 2003, we filed a Feasibility Scoping Plan and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of compliant remedial alternatives for the most contaminated portion of the Gasco site. In May 2007, we completed a revised Remediation Investigation Report and submitted it to the ODEQ for review. We also submitted a Focused Feasibility Study (FFS) for the groundwater source control portion of the Gasco site, which ODEQ conditionally approved in March 2008, subject to the submission of additional information. We provided that information to ODEQ and are now working with the agency on the final design of the source control system. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding remediation, we have estimated a range of liability between $11 million and $30 million, for which we have recorded an accrued liability of $12 million at December 31, 2011. The range of liability will be reassessed when ODEQ makes a final source control design decision, expected later this year.

In addition to groundwater source control, we signed a joint Order on Consent with the Environmental Protection Agency (EPA), which requires us to design remedial action for sediments from the Gasco site. This design project is underway. We also have other investigation and clean-up work, including potential work on the uplands portion of the Gasco site. For the sediments project and upland work, we have recorded an additional accrued liability of $49.2 million, which reflects the low end of the range of potential liability. We have accrued at the low end of the range of potential liability for the work at the Gasco site because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated. However, during 2012, we expect EPA to complete a feasibility study that will provide additional cost information about the sediment cleanup work.

Siltronic site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (Siltronic site). We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ. The liability accrued at December 31, 2011 for the Siltronic site is $1.0 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

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Portland Harbor site. In 1998, the ODEQ and the EPA completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes an area adjacent to the Gasco and Siltronic sites. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties, referred to as the Lower Willamette Group, to fund environmental studies in the Portland Harbor to allow the EPA to develop a feasibility study. Subsequently, the EPA approved a Programmatic Work Plan, Field Sampling Plan and Quality Assurance Project Plan for the Portland Harbor Remedial Investigation/Feasibility Study (RI/FS), completion of which is scheduled for 2012. The EPA and the Lower Willamette Group are conducting more focused studies on approximately nine miles of the lower Willamette River, including the 5.5-mile segment previously studied by the EPA. Further, in August 2008, we signed a cooperative agreement with the Portland Harbor Natural Resource Trustee Council to participate in a phased natural resource damage (NRD) assessment. The NRD assessment is intended to identify additional information necessary to estimate further liabilities to support an early restoration-based settlement of natural resource damage claims. During 2012, the Lower Willamette Group will submit a draft feasibility study for this site to EPA, resulting in more information regarding the scope of potential costs. We expect that the feasibility study will allow us to estimate a range of potential liability and that the range may include significant estimates of potential liability. As of December 31, 2011, we have a liability accrued of $8.2 million for this site, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another, and the high end of the range cannot reasonably be estimated.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (Central Service Center site) was assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas as a result of historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. In early 2008, we received notice that this site was added to the ODEQ's list of sites where releases of hazardous substances have been confirmed and to its list where additional investigation or cleanup is necessary. We are currently performing an environmental investigation of the property with the ODEQ's Independent Cleanup Pathway. As of December 31, 2011, we have a liability accrued of $0.5 million for investigation at this site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. It is near but outside the geographic scope of the current Portland Harbor site sediment studies. The EPA directed the Lower Willamette Group to collect a series of surface and subsurface sediment samples off the river bank adjacent to where that facility was located. Based on the results of that sampling, the EPA notified the Lower Willamette Group that additional sampling would be required. As the Front Street site is upstream from the Portland Harbor site, the EPA agreed that we could manage the site separately from the Portland Harbor site under ODEQ authority. We submitted work plans for source control investigation and a historical report to ODEQ and completed initial studies. In 2010, ODEQ required additional studies which are underway. As of December 31, 2011, we have an estimated liability accrued of $1.7 million for the study of the sediments and riverbank groundwater and soils at the site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Oregon Steel Mills site. See "Other Legal Proceedings," below.

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Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at December 31, 2011 and 2010:

	Current Liabilities		Non-Current Liabilities	
Thousands	2011	2010	2011	2010
Gasco site	$16,510	$11,366	$44,697	$38,921
Siltronic site	887	720	128	201
Portland Harbor site	1,089	2,304	7,066	5,784
Central Service Center site	-	5	495	510
Front Street site	1,697	1	-	1,097
Other sites	-	-	120	108
Total	$20,183	$14,396	$52,506	$46,621

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the OPUC approved our request to defer unreimbursed environmental costs associated with certain named sites, including those described above. Beginning in 2006, the OPUC granted us additional authorization to accrue carrying costs on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the authorized cost deferral and carrying cost accrual was extended through January 2012. We have filed a request with the OPUC to reauthorize this deferral and expect reauthorization during the first half of 2012. In addition, we filed a request with the WUTC in January 2011 to defer certain environmental costs associated with services provided to Washington customers. We received an order from the WUTC on June 20, 2011 granting that request. Environmental costs related to Washington are being deferred as of January 26, 2011 with cost recovery to be determined in a future proceeding.

On a cumulative basis, we have recognized a total of $124.8 million for environmental costs, including legal, investigation, monitoring and remediation costs, including $4.9 million accrued and paid prior to regulatory deferral order approval. At December 31, 2011, we had a regulatory asset of $105.7 million for deferred environmental costs.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon (see Item 3. Legal Proceedings). NW Natural seeks damages in excess of $50 million in losses it has incurred to date, as well as declaratory relief for additional losses it expects to incur in the future. In December 2011, NW Natural reached a settlement with Associated Electric & Gas Insurance Services Limited and dismissed that insurer from the litigation.

Other Legal Proceedings

We are subject to claims and litigation arising in the ordinary course of business. We do not expect that the ultimate disposition of any of these matters, including the matter described below, will have a material effect on our financial condition, results of operations or cash flows.

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

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NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Quarter ended					
Thousands, except per share amounts	March 31	June 30	Sept. 30	Dec. 31	Total	
2011						
Operating revenues	$323,088	$161,197	$93,313	$271,198	$848,796	
Net operating revenues	134,508	67,232	47,783	119,910	369,433	
Net income (loss)	40,773	2,193	(8,312)	29,244	63,898	
Basic earnings (loss) per share	1.53	0.08	(0.31)	1.09	2.39	(1)
Diluted earnings (loss) per share	1.53	0.08	(0.31)	1.09	2.39	(1)
2010						
Operating revenues	$286,529	$162,365	$95,067	$268,145	$812,106	
Net operating revenues	130,926	72,193	46,211	118,251	367,581	
Net income (loss)	43,608	6,888	(7,420)	29,591	72,667	
Basic earnings (loss) per share	1.64	0.26	(0.28)	1.11	2.73	(1)
Diluted earnings (loss) per share	1.64	0.26	(0.28)	1.11	2.73	(1)

(1) Quarterly earnings (loss) per share are based upon the average number of common shares outstanding during each quarter. Because the average number of shares outstanding has changed in each quarter shown, the sum of quarterly earnings (loss) per share may not equal earnings per share for the year. Variations in earnings between quarterly periods are due primarily to the seasonal nature of our business.

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

COLUMN A	COLUMN B	COLUMN C Additions		COLUMN D Deductions	COLUMN E
Thousands (year ended Dec. 31)	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net Write-offs	Balance at end of period
2011					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,950	$1,919	$-	$1,974	$2,895
2010					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$3,125	$1,717	$-	$1,892	$2,950
2009					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,927	$4,201	$-	$4,003	$3,125

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

None.

Item 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

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

(b) Changes in Internal Control Over Financial Reporting

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

There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 9(a).

Item 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning our Board of Directors, its Committees and the Audit Committee financial expert contained in NW Natural's definitive Proxy Statement for the May 24, 2012 Annual Meeting of Shareholders is hereby incorporated by reference. The information concerning "Section 16(a) Beneficial Ownership Reporting Compliance" and "Corporate Governance" contained in our definitive Proxy Statement for the May 24, 2012 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2011	Positions held during last five years
Gregg S. Kantor	54	President and Chief Executive Officer (2009-); President and Chief Operating Officer (2007 - 2008); Executive Vice President (2006 -2007); Senior Vice President, Public and Regulatory Affairs (2003-2006).
David H. Anderson	50	Senior Vice President and Chief Financial Officer (2004-).
Margaret D. Kirkpatrick	57	Vice President and General Counsel (2005-); Partner in the law firm of Stoel Rives LLP (1991- 2005).
Lea Anne Doolittle	56	Senior Vice President (2008-); Vice President, Human Resources (2000-2007).
J. Keith White	58	Vice President, Business Development and Energy Supply/Chief Strategic Officer (2007-); Managing Director, Gas Operations and Wholesale Services (2005-2006); Managing Director and Chief Strategic Officer (2003-2005).
David R. Williams	58	Vice President, Utility Services (2007-); Director of Utility Operations, Districts and managed Labor Relations (2004-2006).
Grant M. Yoshihara	56	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
C. Alex Miller	54	Vice President, Finance and Regulation (2009-); Assistant Treasurer (2008-); General Manager of Rates and Regulatory Affairs (2002-2009).
Stephen P. Feltz	56	Assistant Secretary (2007-); Treasurer and Controller (1999-).
MardiLyn Saathoff	55	Deputy General Counsel (2010-); Chief Governance Officer and Corporate Secretary (2008-); Chief Compliance Officer and Assistant General Counsel, Tektronix, Inc. (2005-2008); General Counsel to Oregon Governor Kulongoski and Business and

		Economic Development Advisor (2003-2005).
David A. Weber	52	President and Chief Executive Officer, NW Natural Gas Storage, LLC and Gill Ranch Storage, LLC (2012 -); Interim President and Chief Executive Officer, NW Natural Gas Storage LLC, and Gill Ranch Storage, LLC (2011-2012); Chief Operating Officer NW Natural Gas Storage, LLC and Gill Ranch Storage LLC (November 2010 - January 2011); Managing Director of Information Services and Chief Information Officer (2005 - 2011); Director of Information Services and Chief Information Officer (2001-2005).

Each executive officer serves successive annual terms; present terms end on May 24, 2012. There are no family relationships among our executive officers, directors or any person chosen to become one of our officers or directors.

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

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ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation" and "Report of the Organization and Executive Compensation Committee" contained in our definitive Proxy Statement for the May 24, 2012 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2011 is reflected in Part III, Item 10, above.

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

The following table sets forth information regarding compensation plans under which equity securities of NW Natural are authorized for issuance as of December 31, 2011 (see Note 6 to the Consolidated Financial Statements):

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
Long-Term Incentive Plan (LTIP) (Target Award)(1)	118,617	n/a	337,788
Restated Stock Option Plan	579,225	$ 42.09	580,650
Employee Stock Purchase Plan	19,917	$ 39.72	136,038
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)(2)	3,723	n/a	n/a
Directors Deferred Compensation Plan (DDCP)(2)	62,831	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)(3)	120,028	n/a	n/a
Total	904,341		1,054,476

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The information captioned "Beneficial Ownership of Common Stock by Directors and Executive Officers" contained in our definitive Proxy Statement for the May 24, 2012 Annual Meeting of Shareholders is incorporated herein by reference.

(1) Shares issued pursuant to the LTIP do not include an exercise price, but are payable when the award criteria are satisfied. If the maximum awards were paid pursuant to the performance-based awards outstanding at December 31, 2011, the number of shares shown in column (a) would increase by 118,617 shares and the number of shares shown in column (c) would decrease by the same amount of shares.

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

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

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

The information captioned "Transactions with Related Persons" and "Corporate Governance" in the Company's definitive Proxy Statement for the May 24, 2012 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2011 and 2010 Audit Firm Fees" in the Company's definitive Proxy Statement for the May 24, 2012 Annual Meeting of Shareholders is hereby incorporated by reference.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

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

2. List of Exhibits filed:

Reference is made to the Exhibit Index commencing on page 120.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHWEST NATURAL GAS COMPANY

Date: February 28, 2012 By: /s/ Gregg S. Kantor
Gregg S. Kantor
President and Chief Executive Officer

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

SIGNATURE	TITLE	DATE
/s/ Gregg S. Kantor Gregg S. Kantor President and Chief Executive Officer	Principal Executive Officer and Director	February 28, 2012
/s/ David H. Anderson David H. Anderson Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 28, 2012
/s/ Stephen P. Feltz Stephen P. Feltz Treasurer and Controller	Principal Accounting Officer	February 28, 2012
/s/ Timothy P. Boyle Timothy P. Boyle	Director)))	
/s/Martha L. Byorum Martha L. Byorum	Director)))	
/s/ John D. Carter John D. Carter	Director)))	
/s/ Mark S. Dodson Mark S. Dodson	Director)))	

/s/ C. Scott Gibson	Director)	
C. Scott Gibson	)	
	)	February 28, 2012
/s/ Tod R. Hamachek	Director)	
Tod R. Hamachek	)	
	)	
/s/ Jane L. Peverett	Director)	
Jane L. Peverett	)	
	)	
/s/ George J. Puentes	Director)	
George J. Puentes	)	
	)	
/s/ Kenneth Thrasher	Director)	
Kenneth Thrasher	)	
	)	
/s/ Russell F. Tromley	Director)	
Russell F. Tromley	)	

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX
To
Annual Report on Form 10-K
For Fiscal Year Ended
December 31, 2011

Exhibit Number	Document
*3a.	Restated Articles of Incorporation, as filed and effective May 31, 2006 and amended June 3, 2008 (incorporated herein by reference to Exhibit 3a. to Form 10-K for 2006, File No. 1-15973).
*3b.	Bylaws as amended May 24, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K dated May 29, 2007, File No. 1-15973).
*4a.	Copy of Mortgage and Deed of Trust, dated as of July 1, 1946, to Bankers Trust and R. G. Page (to whom Stanley Burg is now successor), Trustees (incorporated herein by reference to Exhibit 7(j) in File No. 2-6494); and copies of Supplemental Indentures Nos. 1 through 14 to the Mortgage and Deed of Trust, dated respectively, as of June 1, 1949, March 1, 1954, April 1, 1956, February 1, 1959, July 1, 1961, January 1, 1964, March 1, 1966, December 1, 1969, April 1, 1971, January 1, 1975, December 1, 1975, July 1, 1981, June 1, 1985 and November 1, 1985 (incorporated herein by reference to Exhibit 4(d) in File No. 33-1929); Supplemental Indenture No. 15 to the Mortgage and Deed of Trust, dated as of July 1, 1986 (filed as Exhibit 4(c) in File No. 33-24168); Supplemental Indentures Nos. 16, 17 and 18 to the Mortgage and Deed of Trust, dated, respectively, as of November 1, 1988, October 1, 1989 and July 1, 1990 (incorporated herein by reference to Exhibit 4(c) in File No. 33-40482); Supplemental Indenture No. 19 to the Mortgage and Deed of Trust, dated as of June 1, 1991 (incorporated herein by reference to Exhibit 4(c) in File No. 33-64014); and Supplemental Indenture No. 20 to the Mortgage and Deed of Trust, dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4(c) in File No. 33-53795).
*4b.	Copy of Indenture, dated as of June 1, 1991, between the Company and Bankers Trust Company, Trustee, relating to the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4(e) in File No. 33-64014).
*4c.	Officers' Certificate dated June 12, 1991 creating Series A of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4e. to Form 10-K for 1993, File No. 0-994).
*4d.	Officers' Certificate dated June 18, 1993 creating Series B of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4f. to Form 10-K for 1993, File No. 0-994).
*4e.	Officers' Certificate dated January 17, 2003 relating to Series B of the Company's Unsecured Medium-Term Notes and supplementing the Officers' Certificate dated June 18, 1993 (incorporated herein by reference to Exhibit 4f.(1) to Form 10-K for 2002, File No. 0-994).
*4f.	Form of Credit Agreement between Northwest Natural Gas Company and the banks that are party thereto, with JPMorgan Chase Bank, N.A., as administrative agent and Bank of America, N.A., as syndication agent, dated as of May 31, 2007, including Form of Note (incorporated herein by reference to Exhibit 4 to Form

	10-Q dated November 5, 2010, File No. 1-15973).
*4g.	Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., U.S. Bank National Association, UBS Loan Finance LLC, Wells Fargo Bank, N.A., Merrill Lynch Bank USA, dated as of April 29, 2008, extending the Credit Agreement between Northwest Natural Gas Company and each financial institution with JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated herein by reference to Exhibit 4i.(1) to Form 10-K for 2008, File No. 1-15973).
*4h.	Form of Secured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 4, 2004, File No. 1-15973).
*4i.	Letter Agreement among the Company, JPMorgan Chase Bank, N.A., Bank of America, N.A., U.S. Bank National Association, Wachovia Bank, National Association, Wells Fargo Bank, N.A., Bank of America, N.A., Successor by merger to Merrill Lynch Bank USA, and UBS Loan Finance LLC, dated October 29, 2009 (incorporated herein by reference to Exhibit 4i. to Form 10-K for 2009, File No. 1-15973).
*4j.	Distribution Agreement, dated March 18, 2009, among Banc of America Securities LLC, UBS Securities LLC, J.P. Morgan Securities Inc., and Piper Jaffray and Co. (Incorporated herein by reference to Exhibit 1.1 to Form 8-K dated March 23, 2009, File No. 1-15973).
*4k.	Form of Letter Agreement, dated August 24, 2009, among Banc of America Securities, LLC, UBS Securities LLC, J.P. Morgan Securities Inc., Piper Jaffray & Co. and Wells Fargo Securities, LLC (incorporated herein by reference to Exhibit 4k. to Form 10-K for 2009, File No. 1-15973).
*4l.	Form of Unsecured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated October 4, 2004, File No. 1-15973).
4m.	Gill Ranch Note Purchase Agreement, dated November 30, 2011, among Gill Ranch Storage, LLC and the parties listed thereto.
12	Statement re computation of ratios of earnings to fixed charges.
21	Subsidiaries of Northwest Natural Gas Company.
23	Consent of PricewaterhouseCoopers LLP.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Executive Compensation Plans and Arrangements:

*10b.	Executive Supplemental Retirement Income Plan 2010 Restatement (incorporated herein by reference to Exhibit 10b. to Form 10-K for 2009, File No. 1-15973).
*10c.	Supplemental Executive Retirement Plan, effective September 1, 2004 restated 2011 (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2011, File No. 1-15973).
*10d.	Northwest Natural Gas Company Supplemental Trust, effective January 1, 2005, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.7 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10e.	Northwest Natural Gas Company Umbrella Trust for Directors, effective January 1, 1991, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.5 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10f.	Northwest Natural Gas Company Umbrella Trust for Executives, effective January 1, 1988, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.6 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10g.	Restated Stock Option Plan, as amended effective December 14, 2006 (incorporated herein by reference to Exhibit 10c. to Form 10-K for 2006, File No. 1-15973).
*10h.	Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10h. to Form 10-K for 2009, File No. 1-15973).
*10i.	Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10(e). to Form 10-K for 2008, File No. 1-15973).
*10j.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10(f). to Form 10-K for 2008, File No. 1-15973).
10k.	Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated as of January 1, 2012.
*10l.	Form of Indemnity Agreement as entered into between the Company and each director and certain executive officers (incorporated herein by reference to Exhibit 10l. to Form 10-K for 2009, File No. 1-15973).
*10l.(1)	Form of Indemnity Agreement as entered into between the Company and certain executive officers (incorporated herein by reference to Exhibit 10l.(1) to Form 10-K for 2009, File No. 1-15973).
*10m.	Non-Employee Directors Stock Compensation Plan, as amended effective December 15, 2005 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 16, 2005, File No. 1-15973).

10n.	Executive Annual Incentive Plan, effective February 23, 2012.
*10o.	Form of Agreement to Recoupment Provisions of Executive Annual Incentive Plan, effective as of January 1, 2010 (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2009, File No. 1-15973).
*10p.	Form of Change in Control Severance Agreement between the Company and each executive officer (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2008, File No. 1-15973).
*10q.	Severance agreement dated December 19, 2008 between the Company and Gregg S. Kantor (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 23, 2008, File No. 1-15973).
*10r.	Northwest Natural Gas Company Long-Term Incentive Plan, as amended and restated effective December 15, 2011 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 14, 2011, File No. 1-15973).
10s.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan.
10t.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan.
10u.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan.
10v.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan.
*10w.	Form of Restricted Stock Bonus Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10x.	Form of Consent dated December 14, 2006 entered into by each executive officer (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10y.	Consent to Amendment of Deferred Compensation Plan for Directors and Executives, dated February 28, 2008 entered into by each executive officer (incorporated herein by reference to Exhibit 10bb to Form 10-K for 2007, File No. 1-15973).
*10z.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan relating to a special award to an executive officer (incorporated herein by reference to Exhibit 10z. to Form 10-K for 2009, File No. 1-15973).
*10bb.	Form of Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 14, 2011, File No. 1-15973).

101.	**The following materials from Northwest Natural Gas Company Annual Report on Form 10-K for the fiscal year ended December 31, 2011, formatted in Extensible Business Reporting Language (XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.

** In accordance with Rule 406T of Regulation S-T, the XBRL-related information in Exhibit 101 to this Annual Report on Form 10-K is deemed not filed or part of a registration statement or prospectus for purposes of Section 11 or 12 of the Securities Act, is deemed not filed for purposes of Section 18 of the Exchange Act and otherwise is not subject to liability under these sections

*Incorporated herein by reference as indicated