NORTHWEST NATURAL GAS CO
Form 10-K
February 26, 2010

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, 2009

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 [ ] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer –––[X] Accelerated Filer [ ]

Non-accelerated filer [ ] Smaller Reporting Company [ ]

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

As of June 30, 2009, the registrant had 26,513,188 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 $1,162,927,287.

At February 23, 2010, 26,533,028 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 2010 Annual Meeting of Shareholders, are incorporated by reference in Part III.

NORTHWEST NATURAL GAS COMPANY
Annual Report to Securities and Exchange Commission
on Form 10-K
For the Fiscal Year Ended December 31, 2009
Table of Contents

Table of Contents

GLOSSARY OF TERMS

Average weather: equal to the 25-year average degree days based on temperatures established in our 2003 Oregon general rate case.

Bcf: one billion cubic feet, a volumetric measure of natural gas, roughly equal to 10 million therms.

Btu: British thermal unit, a basic unit of thermal energy measurement. One Btu equals the energy required to raise one pound of water one degree Fahrenheit at atmospheric pressure and 60 degrees Fahrenheit. One hundred thousand Btu's equal one therm.

Core utility customers: residential, commercial and industrial customers on firm service from the utility.

Cost of gas: the delivered cost of gas commodity sold to customers, including the cost of gas purchases, gas withdrawn from storage inventory, gains and losses from commodity hedges, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

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

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

Demand charge: a component in all core utility customer rates that covers the cost of securing firm pipeline

Interruptible service: natural gas service offered to customers (usually large commercial or industrial users) under contracts or rate schedules that allow for temporary interruptions 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 due to changes in the cost to acquire and deliver commodity 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 to a customer that receives both natural gas supply and transportation of that gas from the utility.

Therm: the basic unit of natural gas measurement, equal to 100,000 Btu's. An average residential customer in our service area uses about 700 therms in an average weather year.

Transportation service: service provided to a customer that secures its own natural gas supply and pays the utility only for use of the distribution system to transport it.

Utility margin: utility gross revenues less the associated cost of gas and applicable revenue taxes. Also referred 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.

to as utility net operating revenues.

Weather normalization: a rate mechanism that allows the utility to adjust customers' bills during the winter heating season to reduce variations in margin recovery due to fluctuations from average temperatures.

Table of Contents

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;
- future events or performance;
- trends;
- cyclicality;
- growth;
- development of projects;
- competition;
- exploration of new gas supplies;
- the benefits of liquefied natural gas;
- estimated expenditures;
- costs of compliance;
- potential efficiencies;
- impacts of new laws and regulations;
- projected obligations under retirement plans;
- adequacy of and shift in mix of gas supplies;
- adequacy of regulatory deferrals; and
- environmental, regulatory and insurance recovery.

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 caution you therefore 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.

NORTHWEST NATURAL GAS COMPANY
PART I

ITEM 1. BUSINESS

General

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 September 1997. We maintain operations in Oregon, Washington and California and conduct business through NW Natural, wholly-owned subsidiaries and a joint venture. A reference to NW Natural ("we," "us" or "our") in this report means NW Natural and its subsidiaries and joint venture 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 and terms approved by the Oregon Public Utility Commission (OPUC) or by the Washington Utilities and Transportation Commission (WUTC). Gas distribution also includes transporting gas owned by large customers from the interstate pipeline connection, or city gate, to the customers' facilities for a fee, also approved by the OPUC or WUTC. Approximately 92 percent of our consolidated assets at December 31, 2009, and 88 percent of our consolidated net income in 2009, were related to the local gas distribution segment. 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.

At year-end 2009, we had approximately 668,000 total utility customers, consisting of approximately 605,000 residential, 62,000 commercial and 1,000 industrial sales and transportation customers. Approximately 90 percent of our utility customers are located in Oregon and 10 percent are 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 utility customer or industry accounts for a significant portion of our revenues.

See Note 2 for further information on total assets and results of operations for the years ended December 31, 2009, 2008 and 2007.

Utility Gas Supply, Storage and Transportation Capacity

We meet the expected needs of our core utility customers through natural gas purchases from a variety of suppliers. Our supply and capacity plan is based on forecasted customer requirements and takes into account 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.

Table of Contents

Gas Acquisition Strategy

Our goals in purchasing gas for our core utility customers are:

- Reliability—Ensuring a gas resource portfolio that is sufficient to satisfy core utility customer requirements under extremely cold weather conditions as described below in "Source of Supply – Design Year and Design Day Sendout";
- Lowest reasonable cost—Applying strategies to acquire gas supplies at the lowest reasonable cost for utility customers;
- Price stability—Making use of physical assets (e.g. gas storage and long-term gas reserves) and financial instruments (e.g. financial hedge contracts such as price swaps) to manage commodity price variability; and
- Cost recovery—Managing gas purchase costs prudently to minimize the risks associated with regulatory review and recovery of gas acquisition costs.

To achieve our gas acquisition strategy, we employ a gas purchasing strategy that emphasizes a diversity of supply, liquid trading points, price risk management strategies, asset optimization and regulatory alignment as described below.

Diversity of supply. There are three primary means by which we diversify our gas supply acquisitions: regional supply basins; contract types; and contract durations.

Our utility obtains its gas supplies from three key regional supply basins. They are the Alberta and British Columbia regions in Canada, and the Rocky Mountain region in the United States. 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 are considering shifting more of our supply mix to the U.S. Rocky Mountains based on projections of declining gas imports from western Canada and increased gas production in the U.S. Rocky Mountains. We believe that the cost of natural gas coming from these regions will continue to track respective market prices. Several projects have been built and more are proposed to increase pipeline capacity out of the U.S. Rocky Mountain region, while new technology to extract shale gas resources in recent years continues to increase the availability of gas supply throughout North America. In addition, we also believe the potential development of a liquefied natural gas (LNG) import terminal would benefit the Pacific Northwest. If constructed, an LNG import terminal would introduce a new source of gas supply to our utility customers and the region, thereby increasing the diversity of available sources of energy and increasing the overall supply of natural gas available to meet future demand growth in the region.

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.

Other less frequent types of contracts include non-heating season baseload supplies, non-heating season contracts where the supplier has the option to supply gas to us on a daily basis, and seasonal exchange purchase and sale contracts. We try to maintain a diversified portfolio of purchase arrangements.

We also use a variety of multi-year contract durations to avoid having to re-contract a significant portion of our supplies every year. See "Core Utility Market Basic Supply," below.

Table of Contents

Liquid trading points. 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 various receipt points in the U.S. Rocky Mountains.

Price risk management strategies. Our four primary strategies for managing gas commodity price risk are:

- negotiating fixed prices directly with gas suppliers;
- negotiating financial derivative instruments that effectively convert the floating price in a physical supply contract to a fixed price (referred to as 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 calls, puts, and collars); and
- buying gas and injecting it into storage or buying gas reserves for longer term supply deliveries. See "Cost of Gas," below.

Asset optimization. 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, in an effort to maximize the value of our gas storage and pipeline capacity, we contract with an independent energy marketing company that optimizes our unused capacity when those assets are not serving the needs of our core utility customers. This asset optimization service performed by the independent energy marketing company produces cost savings that reduces our utility's cost of gas, as well as generates incremental revenues from a regulatory incentive sharing mechanism that are included in our gas storage business segment. See Note 2.

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

- re-setting customer rates annually for changes in forecasted purchased gas costs and recovery of customer deferrals of prior year's actual versus forecasted gas purchase 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 Purchased Gas Adjustment (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.

Cost of Gas

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

Supply cost. Volatility in natural gas commodity prices has been dramatic over the last several years primarily due to shifts in the balance of supply and demand, which has been affected by a variety of factors, including weather, changes in demand, the level of production and availability of natural gas, imports 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 disruptions, national and worldwide economic and political conditions, and the price and availability of alternative fuels. We are in a favorable position with respect to gas production because of the proximity of our service territory to supply basins in western Canada and the U.S. Rocky Mountains, where some growth in gas production is expected to continue for the foreseeable future.

Table of Contents

Transportation cost. Pipeline transportation rates charged by our pipeline suppliers have been relatively stable over the last several years. These rates periodically change when pipeline suppliers get approval from the Federal Energy Regulatory Commission (FERC). Pipeline transportation rate increases or decreases are generally passed on to our customers through annual PGA mechanisms.

Gas price hedging. We seek to mitigate the effects of higher gas commodity prices and price volatility on core utility customers by using our underground storage facilities strategically and by entering into financial hedge contracts in an attempt to fix or limit the price of gas commodity purchases. Realized gains or losses from financial commodity hedge contracts are treated as reductions or increases to the cost of gas.

Managing the Cost of Gas

We manage natural gas commodity price risk through active physical and financial hedging programs. 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 program, we are allowed to enter into commodity swaps, puts, calls and collars with terms generally ranging anywhere from one month to five years.

In addition to the prices that are hedged through financial contracts, we also own physical gas supplies in storage. We purchase and inject from 5 to 15 percent of our annual gas supply requirements into storage during the summer when demand and gas prices are generally lower. About 15 percent of our annual gas supply requirements is stored for withdrawal during the winter months in five different storage facilities. We own and operate three of these storage facilities located within our service territory, which reduces the need for additional upstream pipeline capacity and provides significant cost savings. The other two storage facilities are owned and operated by our primary pipeline supplier.

The intended effect of our physical and financial hedging programs is to manage the price exposure for a majority of our gas supply portfolio for the following gas contract year, which begins November 1st of each year, with prices normally hedged for between 50 and 75 percent of year round supplies, including more than 80 percent of our expected winter-heating season supplies based on forecasted customer requirements. We are authorized by our Board of Directors to hedge up to 100 percent of our gas requirements for the next gas contract year.

Source of Supply – Design Year and Design Day Sendout

The effectiveness of our gas supply 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 design day that is based on the coldest weather experienced over 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 million therms. We are currently capable of meeting over 60 percent of our firm customer maximum design day requirements with storage and peaking supply sources located within or adjacent to our service territory, while the remaining gas supply requirements would be met by gas purchases under firm contracts. Optimal utilization of storage and peaking facilities 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 indicating that load forecasting models required very little re-calibration. Similar cold temperatures experienced in December 2008 and December 2009 produced very high sendout days but firm sendout in December 2009 was still about 3 percent below our 2004 record. This primarily reflects a decline in average customer usage. Accordingly, we believe that our supplies would be sufficient to meet firm customer demand if we were to experience design day conditions. We will continue to evaluate and update our forecasts of design day requirements in connection with our integrated resource plan (IRP) process (see "Integrated Resource Plan," below).

Table of Contents

The following table shows the sources of supply that are projected to be used to satisfy the design day sendout for the 2009-2010 winter heating season:

Projected Sources of Supply for Design Day Sendout

Sources of Supply	Therms (in millions)	Percent
Firm supply purchases	3.3	37
Mist underground storage (utility only)	2.4	27
Company-owned LNG storage	1.8	20
Off-system firm storage contracts	1.1	12
Recall agreements	0.4	4
Total	9.0	100

We believe the combination of the natural gas supply purchases under contract, our peaking supplies and the transportation capacity held under contract on the interstate pipelines sufficiently satisfies the needs of existing core utility customers and positions the utility to meet future requirements.

Core Utility Market Basic Supply

We purchase gas for our core utility customers from a variety of suppliers located in western Canada and the U.S. Rocky Mountain area. Currently, about 60 to 70 percent of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. We are considering shifting more of our supply mix to the U.S. Rocky Mountains based on projections of declining gas imports from western Canada and increased gas production in the U.S. Rocky Mountains. At December 31, 2009, we had 29 firm contracts with 20 suppliers and remaining terms ranging from five months to five years, which provide for a maximum of 1.55 million therms of firm gas per day during the peak winter heating season and 0.8 million therms per day during the entire year. These contracts have a variety of pricing structures and purchase obligations. In addition, we have another 0.95 million therms of firm gas capacity whereby we can purchase contract or spot gas supplies for delivery to our system during the peak winter heating season. During 2009, we purchased 783 million therms of gas under contracts with the following durations:

Contract Duration (primary terms)	Percent of Purchases
Long-term (one year or longer)	49
Short-term (more than one month, less than one year)	18
Spot (one month or less)	33
Total	100

We regularly renew or replace our gas supply contracts with new agreements with a variety of existing and new suppliers. Aside from the optimization of our core utility gas supplies by the independent energy marketing company (see “Gas Acquisition Strategy—Asset optimization,” above), our daily contract requirements are provided by multiple sources with no more than three suppliers providing between 5 and 10 percent of our average daily contract volumes. Firm year-round supply contracts have remaining terms ranging from one to five years. Currently, all term gas supply contracts use price formulas tied to monthly index prices. We hedge a majority of these contracts each year using financial instruments as part of our gas purchasing strategy (see “Managing the Cost of Gas,” above).

In addition to the 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 2009, new short-term purchase agreements were entered into with between 15 and 20 suppliers. These agreements provide for a total of up to 1.1

million therms per day during the 2009-2010 heating season. We intend to enter into new purchase agreements in 2010 for equivalent volumes of gas with existing or new suppliers, as needed, to replace contracts that will expire during 2010.

Table of Contents

We also buy gas on the spot market as needed to meet core utility customer demand. We have flexibility under the terms of some of our firm supply contracts, which enables us 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 1 percent of our total annual purchase requirements. Production from these wells varies as existing wells are depleted and new wells are drilled.

Core Utility Market Peaking Supply and Storage

We supplement our firm gas supplies with gas from storage facilities we own or that are contractually committed to us. Gas is generally purchased and stored during periods of low demand 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. We provide daily and seasonal peaking gas supplies to our Oregon core utility customers from our underground gas storage facility in the Mist gas storage field. Including the latest expansions in 2008, this facility has a maximum daily deliverability of 5.1 million therms and a total working gas capacity of about 16 Bcf. In May 2008, a total of 100,000 therms per day of Mist storage capacity that had previously been available for storage services was recalled and committed to use for core utility customers. This was the first recalled capacity since 2004. In May 2009, another 100,000 therms per day of Mist storage withdrawal capacity that had previously been available for interstate storage services was recalled by the utility and committed to use for its core customers. Under our regulatory agreement with the OPUC, non-utility gas storage at Mist has been developed in advance of core utility customer needs for interstate storage services and can be recalled by the utility to serve utility customers. 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. The core utility market now has 2.5 million therms per day of deliverability and approximately 9.4 Bcf of working gas committed from the Mist storage facility.

We also have contracts with the Williams Companies' Northwest Pipeline (Northwest Pipeline) for firm gas storage services from an underground storage facility in Jackson Prairie near Chehalis, Washington, and an LNG facility in Plymouth, Washington. Together, these two facilities provide us with daily firm deliverability of about 1.1 million therms and total seasonal capacity of about 16 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.

Company-owned 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 the peak winter heating season. These two facilities provide a maximum combined daily deliverability of 1.8 million therms and a total seasonal capacity of 17 million therms.

Recallable capacity 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. Another contract for 52,000 therms per day of year-round pipeline capacity expired on June 30, 2009, and the capacity reverted back to the industrial customer. A replacement agreement to reacquire the expired capacity was completed later in 2009 (see "Transportation—Transportation agreements," below).

- 8-

Table of Contents

Transportation

Single transportation pipeline. Our distribution system is directly connected to a single interstate pipeline, Northwest Pipeline. Although we are dependent on a single pipeline, the pipeline's gas flows are bi-directional and, as such, transports gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from 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 need for pipeline transportation diversity. That replacement project was completed by Northwest Pipeline in November 2006. We are pursuing options to further diversify our pipeline transportation paths. Specifically, we are jointly developing plans to build a pipeline (Palomar) that would connect TransCanada Pipelines Limited's (TransCanada) Gas Transmission Northwest (GTN) interstate transmission line to our gas distribution system. In August 2007, 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 an alternate transportation path for gas purchases from Alberta and the U.S. Rocky Mountains that currently move through the Northwest Pipeline system (See Part II, Item 7., "2010 Outlook—Strategic Opportunities—Pipeline diversification").

Transportation agreements. The largest of our transportation agreements with Northwest Pipeline extends through September 2013 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 2011. It provides up to 1.0 million therms per day of firm transportation capacity from the point of interconnection of the 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 gas supply transportation contract starting no earlier than 2012 nor later than 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.

Beginning in December 2009, we took assignment of a long-term firm transportation contract from an industrial customer for approximately 40,000 therms of Northwest Pipeline capacity to serve our utility customers.

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 600,000 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 470,000 therms per day of firm gas 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 BC system and NIT system in British Columbia and Alberta, allowing purchases to be made from the gas fields of Alberta, Canada.

Rates. FERC establishes rates for interstate pipeline transportation service under long-term transportation agreements within the U.S., and Canadian federal or provincial authorities establish rates for service under agreements with the Canadian pipelines over which we ship gas.

Table of Contents

Integrated Resource Plan

The OPUC and WUTC have implemented integrated resource planning processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. These plans are consistent with state and energy policy and include:

· an evaluation of supply and demand resources;
· the consideration of uncertainties in the planning process and the need for flexibility to respond to changes; and
· a primary goal of “least cost” service.

In January 2009, the OPUC acknowledged our 2008 IRP. Although the OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. We filed our 2009 IRP with the WUTC in March 2009. In July 2009, the WUTC provided notice that our 2009 IRP met the requirements of the Washington Administrative Code. The WUTC has indicated that the IRP process is one factor it will consider in a prudency review.

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 and propane. We also compete with electricity and fuel oil 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 gas suppliers is based on price, perceived environmental impact, sustainability, reliability, efficiency and performance, market conditions, technology and legislative policy. 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 sales to our utility customers (see “Industrial Markets,” below).

Residential and Commercial Markets

The relatively low market saturation of natural gas in residential single-family dwellings in our service territory, estimated at approximately 55 percent, and our operating convenience and environmental advantage over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2009, 5,407 net new residential customers were added, primarily from single- and multi-family new construction, but also from the conversion of existing homes from oil, electric or propane appliances to natural gas. The net increase of all new customers added in 2009 was 5,453. This represents a 12-month growth rate of 0.8 percent. 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 percent of gross operating revenues, while industrial customers account for about 40 to 45 percent of volumes and about 12 percent of gross revenues. The remaining 3 percent of gross operating revenues is derived from miscellaneous services and other regulatory charges.

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.

Industrial customer businesses 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 revenues or margins.

The OPUC and WUTC have approved transportation tariffs under which we may contract with customers to deliver customer-owned gas. Transportation tariffs available to industrial customers 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 unaffected financially if industrial customers buy commodity supplies directly from marketers rather than purchasing gas from us, as long as they remain on a tariff or contract with the same level of service. We do not generally make any margin on the sale of the gas commodity. However, industrial customers may select between firm and interruptible service, among other levels of service, and these choices can positively or negatively affect margin as firm service has a higher 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.

Table of Contents

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 cost of gas tariff complete the agreed upon term of their service. In the case of customers switching out-of-cycle from transportation to sales service, the customer will be charged the cost of incremental 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 designed to provide transportation rates that are competitive with the customer's alternative capital and operating costs of installing direct connections to Northwest Pipeline's interstate pipeline system, which would allow them to bypass our gas distribution system. These agreements generally prohibit bypass during their terms. Due to the cost pressures that confront a number of our largest customers competing in global markets, bypass continues to be a competitive threat. Although we do not expect a significant number of our large customers to bypass our system in the foreseeable future, we may experience further deterioration of margin associated with customers transferring to special contracts where pricing is specifically designed to be competitive with their bypass alternative.

Gas Storage

Our gas storage business segment includes natural gas storage services provided to interstate and intrastate customers in the Pacific Northwest using underground gas storage and pipeline facilities we own and operate. We also use an independent energy marketing company to provide asset optimization services for the utility under a contractual arrangement, the results of which are included in this business segment.

Approximately 7 percent of our consolidated assets at December 31, 2009, and 12 percent of our consolidated net income in 2009, are related to the gas storage business segment. For each of the years ended December 31, 2009, 2008 and 2007, this business segment derived its revenues from asset optimization services performed by an independent energy marketing company and from multi-year gas storage contracts with less than 10 customers who contract for service at our Mist storage facility. The total working gas capacity at our Mist gas storage facility is approximately 16 Bcf. Of this capacity, approximately 9.4 Bcf, or 59 percent of storage capacity, is currently used by our utility, and the remaining 6.6 Bcf, or 41 percent, is committed to gas storage customers primarily under firm storage contracts. See Note 2 for more information on total assets and results of operations for the years ended December 31, 2009, 2008 and 2007.

Pre-tax income from gas storage at Mist and third-party optimization 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, or 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 our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage services and third-party optimization activities.

We are currently in the process of developing a second underground gas storage facility and related pipeline in the Fresno, California area. This project is expected to serve the California market. All permits were obtained to begin construction in 2010 (see "Gas storage development," below).

Asset optimization. We contract with an independent energy marketing company to optimize the value of our unused storage and pipeline transportation assets, primarily through the use of commodity transactions and pipeline capacity release transactions.

Seasonality of business. Generally, gas storage revenues do not follow seasonal patterns similar to those experienced by the utility because rates for firm storage contracts are primarily in the form of fixed monthly reservation charges and are not affected by customer usage. However, there is some seasonal variation from the optimization of available utility storage capacity and related transportation capacity. Temporary surplus capacity is usually available during the spring and summer months when the demand for gas by utility customers is low.

Table of Contents

Gas storage customers. Our gas storage business segment generally enters into contracts with customers for firm storage capacity with terms ranging from one to 10 years. Currently, our gas storage revenues are primarily derived from a few large storage customers who provide energy related services, including natural gas distribution, electric generation and energy marketing companies. Five storage customers currently account for over 90 percent of our existing gas storage capacity, with the largest customer accounting for about half of total capacity. These five customers have contracts that expire at various dates between March 2010 and April 2017.

Competitive conditions. Our Mist gas storage facility faces limited competition from other west coast storage projects primarily because of its geographic location. In the future, we could face increased competition from new or expanded natural gas storage facilities as well as from natural gas pipelines, marketers and alternative energy sources.

Interstate gas storage. This part of the business segment currently provides firm and interruptible gas storage services at Mist with related transportation services on the utility's system to and from Mist to interstate pipeline interconnections. The interstate storage services, and maximum rates for these services, are authorized 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.

Intrastate gas storage. We provide intrastate gas storage services under an OPUC-approved rate schedule that includes service and site-specific qualifications. The firm storage service terms and conditions mirror the firm interstate storage service regulated by the FERC, except that these customers are located and served in Oregon.

Gas storage development. In September 2007, we entered into a joint project agreement with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. At that time, we formed a wholly-owned subsidiary, Gill Ranch Storage, LLC (Gill Ranch), to plan and develop the project and to operate the facility. In July 2008, Gill Ranch filed an application with the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity (CPCN). In October 2009, we received an order from the CPUC approving our CPCN. Gill Ranch's provision of market-based rate storage services in California will be subject to CPUC regulation including, but not limited to, service terms and conditions, tariff compliance, systems of accounts, securities issuances, lien grants and sales of property. Our share of the total project cost is estimated to be between $160 million and $180 million, representing 75 percent of the total cost of the initial development, which includes our share of an estimated total 20 Bcf of gas storage capacity and approximately 27 miles of gas transmission pipeline. We are currently in the process of hiring key staff for our gas storage business. In January 2010, we began construction of the Gill Ranch facility. The initial development of the gas storage facility at Gill Ranch is currently targeted to be in-service by the end of the third quarter of 2010.

While our primary focus for growing the gas storage business is on the development at Gill Ranch, we also plan to continue expanding our interstate storage facilities at Mist, Oregon. This past year, we completed three-dimensional seismic surveys and initiated engineering work for a new 3 to 4 Bcf expansion at Mist. Pending confirmation of customer interest in contracting for the additional capacity, we expect to move forward with the project next year and would target a 2011 in-service date. The total project cost estimates are between $45 million and $55 million. This estimated cost range includes the development of a second compression station and a pipeline gathering system at Mist that will enable future storage expansions.

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 based on our current organization structure and decision-making process and 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 (see Part II, Item 7., "2010 Outlook—Strategic Opportunities—Pipeline diversification," below) and pipeline assets in our wholly-owned NNG Financial Corporation, as well as some operating and non-operating expenses of the parent company that cannot be charged to utility operations. Approximately 1 percent of our consolidated assets and consolidated net income are related to activities in the "Other" business segment. See Note 2 for more information on total assets and results of operations for the three years ended December 31, 2009.

Table of Contents

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, terms of services, and systems of accounts established by the OPUC, the WUTC, the FERC and, with respect to Gill Ranch, the CPUC. The OPUC and WUTC also regulate our issuance of securities, as will the CPUC with respect to Gill Ranch. Approximately 90 percent of our utility operating revenues are derived from Oregon customers, and the balance is derived from Washington customers.

We file general rate case and rate tariff requests with the OPUC, WUTC and FERC to periodically change the rates we charge our utility and storage customers. Later this year, we expect to file a storage service tariff with the CPUC with respect to Gill Ranch. With certain exceptions, our most recent agreement with the OPUC precludes us from filing a general rate case request before September 2011, but does not preclude us from filing other types of rate adjustment requests. In 2008, we filed a general rate case in Washington that was approved in December 2008 with the resulting changes to rates 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 and rate approval orders to file every three 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," below and "Business Segments—Gas Storage," above.

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 control environmental effects. 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, including: a property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (Gasco site); a property adjacent to the Gasco site that is now the location of a manufacturing plant owned by Siltronic Corporation (Siltronic site); an area adjacent to the Gasco and the Siltronic sites in the Willamette River that has been listed by the U.S. Environmental Protection Agency as a Superfund site for which we have been identified as one of a number of potentially responsible parties (Portland Harbor site); the former location of a gas manufacturing plant operated by our predecessor that is outside the geographic scope of the current Portland Harbor site (Front Street site); and the former site of three manufactured gas holding tanks (Central Service Center site). 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 11, for a further discussion of potential environmental responses, related costs and regulatory and insurance recovery.

Table of Contents

Future Environmental Issues

We recognize that our businesses are likely to be impacted by future 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 and proposed or enacted state actions to develop statewide or regional programs, each of which have imposed or would impose measures to achieve reductions in greenhouse gas emissions. For example, in December 2009, the U.S. Environmental Protection Agency (EPA) officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, the EPA proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring on or after January 1, 2010. This new rule also requires certain facilities that emit 25,000 metric tons or more of CO2 equivalents per year and certain industries to report certain greenhouse gas emissions data from that facility or industry to the EPA on an annual basis. As we are part of the natural gas distribution industry required to report these emissions, we are evaluating our obligations under this new rule in light of additional guidance to be released by the EPA.

The outcome of 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 imposing reporting obligations on, or limiting emissions of greenhouse gases from, our operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, which could result in an increase in the prices we charge our customers or a decline in the demand for natural gas. On the other hand, because natural gas is a fossil fuel with a relatively low carbon content, it is also possible that future carbon constraints could create additional demand for natural gas for electric production, direct use in homes and businesses and as a reliable and relatively low-emission back-up fuel source for alternative energy sources.

We continue to take steps to address future greenhouse gas emission issues, including actively participating in policy development through the Oregon Governor's Task Force on Climate Change and leading efforts within the American Gas Association to promote the enactment of fair federal climate change legislation. Our President and CEO is a commissioner on the Oregon Global Warming Commission. 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 the introduction of the Smart Energy program, which allows customers to contribute funds to projects that offset greenhouse gases produced from their natural gas use.

Employees

At December 31, 2009, our workforce consisted of 646 members of the Office and Professional Employees International Union (OPEIU), Local No. 11, AFL-CIO, and 415 management level and other non-union employees (see Part II, Item 7., "2010 Outlook—Strategic Opportunities—Business process improvements"). 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 union agreement.

- 14-

Table of Contents

Additions to Infrastructure

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 enhancements and the development of additional gas storage facilities. In 2010, utility capital expenditures are estimated to be between $80 and $90 million, and non-utility capital investments are estimated to be between $120 and $145 million for development projects that are currently in process, including our storage expansion at Mist. For the years 2010-2014, capital expenditures for the utility are estimated to be between $400 and $500 million, while the amount for gas storage and other investments after 2010 will depend largely on future decisions about potential 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 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, as well as proxy materials, filed or furnished pursuant to Section 13(a) or 15(d) and Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

We have adopted a Code of Ethics for all employees and a Financial Code of Ethics that applies to senior financial employees, both of which are available on our website. We intend to disclose amendments to, and any waivers from, such codes 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.

ITEM 1A. RISK FACTORS

Our business and financial results are subject to a number of risks and uncertainties. When considering any investment in our securities, investors should 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. Additional risks and uncertainties not presently known or currently deemed immaterial also may impair our business operations. This list is not exhaustive and the order of presentation does not reflect management's determination of priority or likelihood.

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 customer additions and 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, unemployment rates and mortgage defaults have risen, and the value of homes and investment assets have declined, which has adversely affected the income and financial resources of many domestic households and businesses. It is unclear whether the federal responses to these conditions will lessen the severity or duration of this economic downturn. Our operations and financial results are affected by these economic conditions. Less new housing construction, fewer conversions to natural gas, higher levels of residential foreclosures and vacancies, and personal and business bankruptcies or reduced spending could all result in a decline in energy consumption and customer growth, a slowing of collections from our customers, and a higher than normal level of accounts receivable and bad debts, all of which could have a negative effect on our financial condition and results of operations.

Table of Contents

Regulatory risk. Regulation of our business, 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, 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, FERC has regulatory authority over our interstate gas storage services, and the CPUC has regulatory authority over our Gill Ranch gas storage operations.

The rates we charge to customers must be approved by the applicable regulatory agencies. Our rates are generally designed to allow us to recover the costs of providing such services and to earn an adequate return on our capital investment. However, we expect the rates charged to customers of Gill Ranch for gas storage services will be based on what customers are willing to pay (i.e. market-based rates) rather than on our recovery of costs plus a reasonable return on our investment (i.e. cost-based rates). We also expect to continue to make expenditures to expand, improve and operate our distribution and storage systems. Regulators can deny recovery of expenditures we make if they find that such expenditures were not prudently incurred according to their regulatory standards.

In addition, in the normal course of our 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.

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.

In recent years, we have seen a significant increase in the volatility of natural gas commodity prices, primarily due to shifts in the balance of supply and demand. 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, imports of natural gas, including LNG, 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. The cost we pay for natural gas is generally passed through to our customers through an annual PGA rate adjustment in Oregon and Washington (see below). Significant increases in the commodity price of natural gas raises the cost of energy to our existing customers, thereby causing those customers to conserve or potentially 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. In Oregon, we also have a price-elasticity adjustment that adjusts rates through the annual PGA for expected increases or decreases in customer usage due to higher or lower gas prices. The Oregon PGA tariff also provides an incentive to the Company to achieve lower gas costs such that a percentage, set annually, of any difference between the estimated average PGA gas cost in rates and the actual average gas cost incurred be recognized as current income or expense (see Part II, Item 7., “Results of Operations—Regulatory Matters—Rate Mechanisms”). 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.

Table of Contents

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, debt capital markets 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/or 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.

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

Our gas purchasing requirements expose us to risks of commodity price movements, while our use of debt and equity financing exposes us to interest rate, liquidity and other financial market risks. 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 derivatives policy guidelines. 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.

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.

Table of Contents

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. 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.

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 market 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 and storage businesses are 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, reliability, efficiency and performance.

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 could also erode our competitive advantage. If natural gas prices rise relative to other energy sources, 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.

Our existing gas storage segment currently faces limited competition from other west coast storage projects primarily because of its geographic location. In the future, we could face increased competition from new or expanded natural gas storage facilities, interstate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers.

Reliance on third parties to supply natural gas risk. We rely on third parties to supply substantially all of the natural gas we store and deliver, and limitations on our ability to obtain supplies 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 deliver 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 such as occurred with Hurricane Katrina in 2005; 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.

Table of Contents

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, 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 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. 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 would negatively impact our results of operations

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. We are in the early development stage on the Palomar gas transmission pipeline in Oregon, and we have begun construction of Gill Ranch gas storage facility in California. We may also engage in other business development projects in the future, including expansion of our storage facility at Mist. 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, changes in market prices, and operating cost increases.   Additionally, natural gas storage and transportation markets are intensely competitive, both within the natural gas industry and with alternative sources of energy. To complete our business development projects, we will need to secure financing from willing investors at reasonable cost. If credit markets are inaccessible, we may be unable fund our business development projects at acceptable interest rates within a timeframe favorable for completing the project. Similarly, an inability to obtain the necessary state permits, or arrange for sufficient supplier commitments could impact the viability of an LNG terminal on the Columbia river and may mean that we would not proceed with the western portion of Palomar. One or more of these events may mean that our equity investments could become 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 decreases 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 non-utility development projects, including Palomar and Gill Ranch, and we may acquire interests in other similar types of 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. 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. Although we have contractual and other legal remedies to enforce our interests, if a participant in one of these business arrangements acts contrary to our interests, it could adversely impact the project as well as our financial condition, results of operations and cash flows.

Environmental 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, but our results of operations may be adversely affected to the extent that estimates of the probable costs increase significantly as additional information becomes available and to the extent we are not able to recover the incremental cost from insurance or through customer rates. A regulatory asset has already been recorded for estimated costs pursuant to a deferral order from the OPUC. To the extent we are unable to recover these deferred costs in rates or through insurance, we would be required to reduce our regulatory asset which would adversely affect our results of operations and financial condition. 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 associated costs and uncertain outcomes.

Table of Contents

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, because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Moreover, there are no assurances that existing environmental regulations will not be revised or that new stricter regulations seeking to protect the environment will not be adopted or become applicable to us. 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 customer rates.

Global climate change risk. Management expects that 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 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 impose on us reporting requirements, 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, and could impact the prices we charge our customers, 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 (and potential 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 a 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.

Weather risk. Our results of operations may be negatively affected by warmer than average or colder than average weather.

We are exposed to weather risk primarily in our utility business segment. A majority of our volume is driven from gas sales made to space heating residential and commercial customers during each winter heating season. Current utility rates are based on an assumption of average weather. Weather that is warmer than average typically results in lower gas sales. Sustained colder weather typically results in higher gas sales. Although the effects of warmer or colder weather on utility margin in Oregon are intended to be largely mitigated through the operation of our weather normalization mechanism, colder weather could adversely affect utility margin so we may be required to purchase gas at spot rates in a rising price market to secure sufficient volumes to meet customer requirements. Approximately 9 percent of our Oregon residential and commercial customers have opted out of the weather normalization mechanism and another 10 percent are 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 affect on our financial condition, results of operations and cash flows.

Customer conservation risk. Customers' conservation efforts may have a negative impact on our revenues.

An increasing national focus on energy conservation, including improved building practices and appliance efficiencies, may result in increased energy conservation by customers, 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.

Operating risk. Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.

Our gas distribution activities are subject to a variety of operating hazards and risks that cannot be completely avoided, such as leaks, accidents, mechanical problems, fires, explosions, earthquakes, floods, storms, landslides and other adverse weather conditions and hazards, which could cause substantial financial losses. In addition, our distribution facilities and equipment are subject to third party damage from construction activities and vandalism. These risks could result in loss of human life, significant damage to property, environmental pollution and disruption of our operations, which in turn could lead to financial losses. The occurrence of any of these events may not be fully covered by our insurance policies or be recoverable through rates, which could adversely affect our financial condition and results of operations.

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 actual acts of terrorism that could target or impact our natural gas distribution, transmission and storage facilities and result in a disruption in our operations and ability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Threatened or actual national disasters or terrorist activities may also disrupt capital markets and our ability to raise capital, or impact our suppliers or our customers directly. Local disaster or pandemic illness could result in part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. We maintain emergency planning and training programs to remain ready to respond to events that could cause business interruption. However, a slow or inadequate response to events may have an adverse impact on operations and earnings. We may not be able to obtain sufficient insurance to cover all risks associated with local and national disasters, pandemic illness, terrorist activities and other events, which could increase the risk that an event could adversely affect our operations or financial results.

Employee benefit risk. The cost of providing pension and postretirement healthcare benefits is subject to changes in pension asset values, changing employee demographics and actuarial assumptions, which may have an adverse effect on our financial results.

We provide pension plans and postretirement healthcare benefits to eligible full-time employees. Our cost of providing such benefits is subject to changes in the market value of our pension assets, changing employee demographics, including longer life expectancies of beneficiaries, increases in healthcare costs, current and future legislative changes and various actuarial calculations and assumptions. The actuarial assumptions used to calculate our future pension and postretirement healthcare expense may differ materially from actual results due to significant market fluctuations and changing withdrawal rates, wage rates, interest rates and other factors. These differences may result in an adverse impact on the amount of pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond prices 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.

Table of Contents

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

Our ability to implement our business strategy and serve our customers in our gas distribution business 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 to our customers and meet our regulatory requirements will be challenged and this could negatively impact our earnings. Additionally, a majority of our workers are represented by Office and Professional Employees International Union Local No.11 AFL-CIO (the Union) and are covered by a collective union agreement that will expire May 31, 2014. Disputes with the Union over terms and conditions of the collective union agreement could result in instability in our labor relationship and work stoppages that could impact the timely delivery of our product and services, which could strain relationships with customers and state regulators and cause a loss of revenues which could adversely affect our results of operations. The collective union agreement may also increase the cost of employing our 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.

Legislative and taxing authority risk. We are subject to governmental regulation, and our 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. For example, Oregon legislation that became effective in 2006 requires that utilities not collect in rates more income taxes than they actually pay to taxing authorities. If amounts paid differ from amounts collected by more than $100,000, then we are required to implement a rate schedule with an automatic adjustment to refund or collect the difference, which could be material.

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. Unforeseen changes in laws, regulations or adverse judgments may negatively affect our financial condition and results of operations.

Business improvements risk. Our efforts to integrate, consolidate and streamline our operations have resulted in increased reliance on technology and third party vendors, the failure 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; an automated meter reading system, which allows for electronic reading of customers meters; 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.

Table of Contents

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments.

ITEM 2. PROPERTIES

Utility Properties

Our natural gas distribution system consists of approximately 13,800 miles of distribution and transmission mains located in our service territory in Oregon and Washington. In addition, the distribution system includes service pipes, meters and regulators, and gas regulating and metering stations. The 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 the Willamette River and a number of smaller rivers by our mains.

We own service 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 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 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 or replaced 100 percent of our cast iron mains by October 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 interests in approximately 8,500 net acres of underground natural gas storage in Oregon and approximately 1,900 net acres of underground natural gas storage in California. We also hold interests in approximately 1,600 net acres of oil and gas leases in Oregon. 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 11, we have only routine nonmaterial litigation in the ordinary course of business.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the quarter ended December 31, 2009.

Table of Contents

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:

	2009		2008	
Quarter Ended	High	Low	High	Low
March 31	$45.66	$37.71	$50.74	$41.07
June 30	46.07	39.58	48.22	43.08
September 30	46.00	41.12	55.23	43.66
December 31	46.47	40.83	53.71	36.61

The closing quotations for our common stock on December 31, 2009 and 2008 were $45.04 and $44.23, respectively.

(B) As of December 31, 2009, there were 7,418 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	2009	2008
February 15	$0.395	$0.375
May 15	0.395	0.375
August 15	0.395	0.375
November 15	0.415	0.395
Total per share	$1.600	$1.520

The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. Our Board of Directors expects 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.

Table of Contents

(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 31, 2009:

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
10/01/09 - 10/31/09	2,285	$43.19	-	-
11/01/09 - 11/30/09	24,416	$42.96	-	-
12/01/09 - 12/31/09	1,805	$45.00	-	-
Total	28,506	$43.11	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2009, 25,126 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 3,380 shares of our common stock were purchased on the open market during the quarter under equity-based programs. During the three months ended December 31, 2009, 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 for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We have Board authorization through May 31, 2010 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. For the year ended December 31, 2009, no shares of our common stock were purchased pursuant to this program. Since the program’s inception in 2000 we have repurchased 2.1 million shares of common stock at a total cost of $83.3 million.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

	For the year ended December 31,				
Thousands, except per share amounts and ratio of earnings to fixed charges	2009	2008	2007	2006	2005
Utility operating revenues:					
Residential sales	$555,844	$566,840	$555,312	$536,468	$471,502
Commercial sales	292,697	298,943	298,800	290,666	250,287
Industrial - firm sales	41,407	46,579	54,567	66,986	64,507
Industrial - interruptible sales	62,116	68,978	74,876	93,107	100,740
Total gas sales revenues	952,064	981,340	983,555	987,227	887,036
Transportation	13,635	14,288	14,191	12,800	10,755
Regulatory adjustment for income taxes paid (1)	5,884	1,760	5,996	-	-
Other	21,166	21,784	12,228	161	2,862
Total gross utility operating revenues	992,749	1,019,172	1,015,970	1,000,188	900,653
Cost of gas sold	611,088	656,504	639,094	648,081	563,772
Revenue taxes	24,656	25,072	25,001	24,840	21,633
Utility net operating revenues	357,005	337,596	351,875	327,267	315,248
Non-utility net operating revenues	19,882	18,619	17,167	12,909	9,745
Net operating revenues	$376,887	$356,215	$369,042	$340,176	$324,993
Net income	$75,122	$69,525	$74,497	$63,415	$58,149
Average common shares outstanding:					
Basic	26,511	26,438	26,821	27,540	27,564
Diluted	26,576	26,594	26,995	27,657	27,621
Earnings per share of common stock:					
Basic	$2.83	$2.63	$2.78	$2.30	$2.11
Diluted	$2.83	$2.61	$2.76	$2.29	$2.11
Dividends paid per share of common stock	$1.60	$1.52	$1.44	$1.39	$1.32
Total assets - at end of period	$2,399,252	$2,378,152	$2,014,061	$1,956,856	$2,042,304
Long-term debt	$601,700	$512,000	$512,000	$517,000	$521,500
Ratio of earnings to fixed charges	3.86	3.76	3.92	3.40	3.32

(1) Regulatory adjustment for income taxes paid is the result of the implementation of the utility regulation in 2007 (see Part II, Item 7., "Business Segments – Utility Operations—Regulatory Adjustment for Income Taxes Paid.")

Table of Contents

SELECTED FINANCIAL DATA (continued)

	For the year ended December 31,				
Thousands, except customer and gas cost per therm data	2009	2008	2007	2006	2005
Capitalization - at end of period					
Common stock equity	$660,105	$628,373	$594,751	$599,545	$586,931
Long-term debt	601,700	512,000	512,000	517,000	521,500
Total capitalization	$1,261,805	$1,140,373	$1,106,751	$1,116,545	$1,108,431
Gas sales and transportation deliveries (therms):					
Residential	412,867	428,787	398,960	382,665	371,538
Commercial	255,593	265,531	249,659	242,683	233,987
Industrial - firm	39,447	47,340	52,340	66,971	74,880
Industrial - interruptible	72,525	87,484	89,128	112,736	149,106
Total gas sales	780,432	829,142	790,087	805,055	829,511
Transportation	350,933	431,609	424,882	387,594	328,056
Total volumes delivered	1,131,365	1,260,751	1,214,969	1,192,649	1,157,567
Customers (average for period):					
Residential	601,989	594,481	580,346	564,700	545,163
Commercial	62,142	61,756	60,749	59,889	58,914
Industrial - firm	610	625	634	650	666
Industrial - interruptible	169	180	189	197	201
Transportation	158	136	128	99	78
Total customers	665,068	657,178	642,046	625,535	605,022
Customer statistics:					
Heat requirements:					
Actual degree days	4,383	4,576	4,374	4,089	4,178
Percent colder (warmer) than average	3 %	7 %	3 %	(4 %)	(2 %)
Average annual use per customer in therms:					
Residential	686	721	687	678	682
Commercial	4,113	4,300	4,110	4,052	3,972
Gas purchased cost per therm - net (cents)	71.96	86.56	75.00	75.37	71.42

Table of Contents

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, 2009, 2008, and 2007. Unless otherwise indicated, references in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in this report.

The consolidated financial statements principally consist of the accounts of NW Natural and its wholly-owned subsidiaries, NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch), and an equity investment in a proposed natural gas pipeline. These accounts include our regulated local gas distribution business, our regulated gas storage business, 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 segment, and the term "non-utility" is used to describe our gas storage segment (gas storage) as well as our other regulated and non-regulated investments and business activities (other segment) (see "2010 Outlook—Strategic Opportunities," below, and Note 2).

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 earnings. All references in this section to earnings per share are on the basis of diluted shares (see Note 1). We also show operating revenues and margins excluding the refund of gas cost savings to customers in June and July 2009 because we believe it provides a more meaningful comparison of operating revenues and margins between 2008 and 2009. We use such non-GAAP (i.e. non-generally accepted accounting principles) measures in analyzing our financial performance and believe that they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

Executive Summary

Highlights of 2009:

- Consolidated net income and earnings per share increased 8 percent to all time record highs of $75.1 million and $2.83 per share, respectively;
- Net operating revenues increased 6 percent to $376.9 million;
- Operations and maintenance expense increased 12 percent to $127.1 million;
- Cash flow from operations increased $205.6 million to $240.3 million;
- Permits were approved to proceed with the development at Gill Ranch, and construction began in January 2010;
- A new five-year contract was executed with our union employees, effective in July 2009; and
- The quarterly common stock dividend was increased 5 percent to 41.5 cents per share in the fourth quarter of 2009, making this the 54th consecutive year of increasing dividends paid to shareholders.

Our primary businesses consist of regulated utility and gas storage operations. Factors critical to the success of the regulated 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 Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Factors critical to the success of our regulated gas storage business include: developing and operating storage capacity at competitive market prices; retaining existing 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 customers; obtaining timely approval of reasonable rate increases; and with respect to future development of gas storage projects, being able to obtain financing to fund future development. Our existing gas storage business rates are approved by the Federal Energy Regulatory Commission (FERC) for interstate customers or the OPUC for intrastate customers. The Gill Ranch gas storage project currently under development is subject to regulation by the California Public Utilities Commission (CPUC) (see "2010 Outlook—Strategic Opportunities—Gas Storage Development," below).

Table of Contents

2010 Outlook

In 2010, we intend to remain focused on improving our core businesses, enhancing our strategic position, advancing business development projects related to our primary businesses, and strengthening our organizational effectiveness. The following is a brief summary of management's plans and objectives in these four areas. For a detailed discussion of these areas, see "Issues, Challenges and Performance Measures," and "Strategic Opportunities," below.

Business improvements. We continue to integrate, consolidate and streamline operations using recently implemented new technology improvements, which include an enterprise resource planning system, an automated dispatching system and an automated meter reading system. These and other new technologies support our operating model.

Strategic position. We remain committed to creating shareholder value while balancing the interests of our customers, employees and the communities we serve. To create value, we will respond to business challenges and opportunities that lie ahead, including finding innovative solutions to economic and environmental challenges as well as regulatory, business development and workforce challenges and opportunities.

Business development. In addition to exploring new growth opportunities, we intend to continue advancing key natural gas infrastructure investments during 2010, including our gas storage project in California and our gas transmission pipeline project in Oregon.

Organizational effectiveness. Our employees are our most valued resource. We intend to support our employees with a positive work environment, on-going training opportunities, continued refinement of our organizational structure and new technologies to achieve our goals and facilitate improvements to our operating model.

Issues, Challenges and Performance Measures

Economic weakness. Continued weakness in local and U.S. economies have resulted in reduced consumer demand and business spending. These conditions may continue to have a negative impact on our financial results, reflecting slower customer growth, reduced industrial margins, increased bad debt expense, and higher pension costs.   Most recently, our annual customer growth rate slowed to 0.8 percent in 2009 compared to 1.6 percent in 2008. We expect our customer growth rate in 2010 to stabilize near 2009 levels, unless economic conditions deteriorate further. Despite challenging market conditions, we believe we are well positioned to continue adding customers due to our relatively low market penetration, our efforts to convert homes 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 designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. We entered the 2009-10 gas year, that began November 1, 2009, hedged at a targeted level of approximately 75 percent of our estimated gas purchase volumes for the gas contract year, and we believe we have sufficient contracted supplies to meet the needs of our core utility customers. In addition, we are currently hedged on gas prices for between 10 and 15 percent of our forecasted purchase volumes for the two gas contract years after October 31, 2010. We have Board authorization to hedge up to 100 percent of our gas supply requirements for the next gas contract year. Our Purchased Gas Adjustment (PGA) mechanism, along with gas price hedging strategies and gas supplies in storage, enables us to reduce earnings risk exposure to higher gas costs. In addition to hedging gas prices over the next three years, we are also evaluating and developing other gas acquisition strategies to potentially manage gas price volatility for customers beyond three years.

Environmental investigation and remediation 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 required to defer certain costs pursuant to regulatory decisions by the OPUC or WUTC, including environmental costs, and to seek recovery of these amounts in future rates to customers. However, before we can seek recovery from customers, we must pursue recovery from insurance policies. 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 11.

Climate change. We recognize that our businesses are likely to be impacted by future carbon constraints. The outcome of federal, state, local and international climate change initiatives cannot be determined at this time, but these initiatives could produce a number of results including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. 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. On the other hand, because natural gas is a fossil fuel with a relatively low carbon content, it is also possible that future carbon constraints could create additional demand for natural gas for electric production, direct use in homes and businesses and as a reliable and relatively low-emission back-up fuel source for alternative energy sources.

Strategies and performance measures. In order to deal with the challenges affecting our business, we annually review and update our strategic plan to map our course over the next several years. Our plan includes strategies for: improving our utility gas distribution business; growing our non-utility gas storage business; investing in new natural gas infrastructure in the region; and maintaining a leadership role within the natural gas 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 of certain 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; capital, operations and maintenance expense per customer; and non-utility earnings before interest, taxes, depreciation and amortization (non-utility EBITDA).

Strategic Opportunities

Business process improvements. To address the current economic and competitive challenges, we continue to evaluate and implement business strategies to improve efficiencies. Our goal is to integrate, consolidate and streamline operations and support our employees with new technology tools.

In 2009, we completed the implementation of our new enterprise resource planning (ERP) system, which is designed to reduce the number of technology platforms and improve overall operating efficiencies by:

- integrating systems and data;
- automating control procedures and workflows; and
- improving management decision-making and financial reporting processes.

In 2009, we also completed our project to automate the reading of gas meters (AMR). Meters equipped with this new technology electronically transmit usage data to receiving devices located in our vehicles as they drive in the area, substantially reducing the labor costs associated with reading meters. The total capital cost of this project was approximately $25 million (see “Results of Operations—Regulatory Matters—Rate Mechanisms—AMR Deferral,” below).

In 2008 and 2009, we deployed an automated dispatching system, which provides integrated planning and scheduling with global positioning system capabilities to more effectively collect and distribute data. We will continue to deploy this new technology in the field during 2010.

In 2009, we announced a voluntary severance program to reduce staffing levels in response to work load declines related to slower customer growth and efficiency improvements. Severance programs and normal attrition resulted in reductions of full-time positions from 1,133 at December 31, 2008 to approximately 1,020 in early 2010. We incurred severance charges in the fourth quarter of approximately $1.5 million, which were partially offset by savings from vacated positions prior to the end of the year. We also expect some additional position reductions in 2010, but those reductions will most likely come from normal attrition.

Table of Contents

Technology investments, workforce reductions and the other initiatives discussed above are expected to facilitate process improvements, contribute to long-term operational efficiencies and reduce operating expenses throughout NW Natural.

Gas storage development. In 2007, we entered into a joint project agreement with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. At that time, we formed a wholly-owned subsidiary, Gill Ranch, to plan and develop the project and to operate the facility. In July 2008, Gill Ranch filed an application with the CPUC for a Certificate of Public Convenience and Necessity (CPCN). In October 2009, we received an order from the CPUC approving our CPCN. Gill Ranch's provision of market-based rates for storage services in California will be subject to CPUC regulation including, but not limited to, service terms and conditions, tariff compliance, securities issuances, lien grants and sales of property. Our share of the total project development cost is estimated to be between $160 million and $180 million, representing 75 percent of the total cost of the initial development, which includes an estimated total 20 Bcf of gas storage capacity and approximately 27 miles of gas transmission pipeline. In January 2010, we began construction on the Gill Ranch facility. The initial development of the gas storage facility at Gill Ranch is currently targeted to be in-service by the end of the third quarter of 2010.

We are currently in the process of hiring key staff for our non-utility gas storage businesses. While our primary focus for growing the gas storage business is on the current development at Gill Ranch, we also plan to continue expanding our interstate storage facilities at Mist, Oregon. In 2009, we completed three-dimensional seismic surveys and initiated engineering work for a new 3 to 4 Bcf expansion at Mist. Pending successful marketing efforts, we expect to move forward with the project and would target a 2011 in-service date. Currently, our total cost estimates are between $45 million and $55 million for this expansion project. This estimated cost range includes the development of a second compression station and a pipeline gathering system that will also enable future storage expansions at Mist.

Pipeline diversification. Currently, we depend on a single bi-directional interstate pipeline to ship gas supplies to our utility distribution system. Palomar Gas Transmission, LLC, a wholly-owned subsidiary of Palomar Gas Holdings, LLC, (PGH), is seeking to build a new gas transmission pipeline that would provide a new interconnection with our utility distribution system. PGH is owned 50 percent by NW Natural and 50 percent by Gas Transmission Corporation (GTN), an indirect wholly-owned subsidiary of TransCanada Corporation. The proposed Palomar pipeline is a 217-mile natural gas transmission pipeline in Oregon designed to serve our utility and the growing markets in Oregon and other parts of the western United States. The Palomar pipeline would be regulated by the FERC. In December 2008, Palomar filed for a CPCN with the FERC.

The Palomar project includes an east and west segment. The east segment would extend approximately 111 miles west from an interconnection with GTN's existing interstate transmission mainline near Maupin, Oregon to an interconnection with NW Natural's gas distribution system near Molalla, Oregon. The west segment would then extend approximately 106 miles further west to other potential additional interconnections including a possible connection to one of the two liquefied natural gas (LNG) terminals proposed to be built on the Columbia River. The east segment would not only diversify NW Natural's gas delivery options and enhance the reliability of service to our utility customers by providing an alternate transportation path for gas purchases from different regions in western Canada and the U.S. Rocky Mountains, but also provide potential access to other shippers in the region. The west segment of Palomar would provide the region, as well as our utility customers with potential access to a new source of gas supply if an LNG terminal is built on the Columbia River. Palomar will continue to focus on permitting activities during 2010, and we believe the FERC will issue a draft Environmental Impact Statement during the first quarter of 2010. The date for when Palomar is expected to go into service will be impacted by the timing of our final FERC permit and the needs of shippers. In addition, the development of LNG terminals along the Columbia River may or may not proceed, which may affect the development of the west segment of Palomar. See "Financial Condition—Cash

Flows—Investing Activities," below for further discussion on the status of Palomar.

Table of Contents

Consolidated Earnings and Dividends

Net income was $75.1 million, or $2.83 per share, for the year ended December 31, 2009, compared to $69.5 million, or $2.61 per share, and $74.5 million, or $2.76 per share, for the years ended December 31, 2008 and 2007, respectively. Consolidated returns on average common equity for these three years were 11.7 percent, 11.4 percent and 12.5 percent, respectively.

2009 compared to 2008:

Factors contributing to increased earnings were:

- a $20.6 million increase in utility net operating revenue (margin) from our regulatory share of gas cost savings, reflecting a contribution to margin of $15.1 million in 2009 compared to a reduction to margin of $5.5 million in 2008;
- a $4.1 million increase in utility margin from the regulatory adjustment for income taxes paid; and
- a $1.3 million increase in margin from gas storage operations.

Partially offsetting the above factors were:

- a $13.7 million increase in operations and maintenance expense primarily due to higher expenses for pensions, bonuses, health care benefits and employee severance;
- a $6.0 million increase in income tax expense related to higher taxable income and a higher state income tax rate; and
- a $2.1 million decrease in utility margin from industrial customers, reflecting weak economic conditions and a decrease in depreciation rates.

2008 compared to 2007:

Factors contributing to decreased earnings were:

- a $5.5 million loss in utility margin from our regulatory share of gas cost increases in 2008 compared to a margin gain of $12.1 million in 2007 from gas cost decreases;
- a $4.2 million decrease in utility margin from a lower customer surcharge related to regulatory adjustments for income taxes paid;
- a $3.8 million increase in depreciation expense primarily due to increased utility plant in service;
- a $2.9 million decrease in margin due to a temporary mark-to-market gain in 2007; and
- a $1.6 million decrease in utility margin from industrial customers due to weaker economic conditions.

Partially offsetting the above factors were:

- a $7.1 million increase in utility margin from higher sales volumes to residential and commercial customers due to colder weather and customer growth, after decoupling and weather mechanism adjustments;
- a $7.1 million decrease in operation and maintenance expense, partially due to higher costs in 2007 for strategic initiatives, and partially due to lower bonuses and employee benefit costs in 2008;
- a $3.4 million decrease in income tax expense due to lower taxable income;
- a $1.1 million after-tax gain from the sale of our investment in an aircraft leased to a commercial airline; and
- a $0.8 million increase in utility margin due to curtailment charges for use by a small number of industrial customers during cold weather.

Dividends paid on our common stock were $1.60 per share in 2009, compared to $1.52 per share in 2008. In October 2009, the Board of Directors declared a quarterly dividend on our common stock of 41.5 cents per share, payable on November 13, 2009, increasing the indicated annual dividend rate to $1.66 per share.

Table of Contents

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America (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 1.

Regulatory Accounting

We are regulated by the OPUC and WUTC, which establish our utility rates and rules governing utility services provided to customers, and, to a certain extent, set forth the accounting treatment for certain regulatory transactions. In general, we use the same accounting principles as non-regulated companies reporting under GAAP. However, authoritative guidance for regulated operations (regulatory accounting) require different accounting treatment for regulated companies to show the effects of such regulation. For example, we account for the cost of gas using a PGA deferral and cost recovery mechanism, which is submitted for approval annually to the OPUC and WUTC (see "Results of Operations—Regulatory Matters—Rate Mechanisms," below). There are other expenses or 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 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 we meet all three conditions, we continue to apply regulatory accounting principles for our regulated 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 regulated activities, and that all of our regulatory assets and liabilities at December 31, 2009 and 2008 are recoverable or refundable through future customer rates. See Note 1, “Industry Regulation.”

Table of Contents

Revenue Recognition

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized when gas is delivered to and received by the customer. Revenues are accrued for gas delivered to customers, but not yet billed, based on estimates of gas deliveries from the last meter reading date to month end (accrued unbilled revenues). Accrued unbilled revenues are primarily based on a percentage estimate of our unbilled gas deliveries 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, 2009 and 2008 were $71.2 million and $102.7 million, respectively. The decrease in accrued unbilled revenues at year-end 2009 was primarily due to lower volumes in 2009 reflecting warmer weather in late December 2009 and lower customer rates. If the estimated percentage of unbilled volume at December 31, 2009 was adjusted up or down by 1 percent, then our unbilled revenues, net operating revenues and net income would have increased or decreased by an estimated $2.3 million, $0.1 million and $0.6 million, respectively.

Utility revenues may also include the recognition of a regulatory adjustment for income taxes paid. This revenue reflects an OPUC rule whereby we are required to automatically implement a rate refund or a rate surcharge to utility customers. This refund or surcharge is accrued based on the estimated difference between income taxes paid and income taxes authorized to be collected in rates (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 optimization partner are recognized over the life of the optimization contract for the guaranteed amount, and recognized as earned for amounts above the guaranteed amount.

Accounting for Derivative Instruments and Hedging Activities

Our gas acquisition 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 fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to regulatory accounting (see Note 1, "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 1, "Derivatives" and "Industry Regulation"). Our derivative contracts outstanding at December 31, 2009 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 values on unrealized gains and losses at December 31, 2009 and 2008, see Note 10.

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 other comprehensive income for contracts qualifying for hedge accounting.

Derivative hedge contracts are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2009, 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.

Table of Contents

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

Thousands	2009	2008	2007
Net gain (loss) on commodity-price swaps - utility	$(172,089)	$34,256	$(41,954)
Net gain (loss) on commodity-price options - utility	(5,809)	1,527	(662)
Net gain (loss) on interest rate swap - utility	(10,096)	-	-
Subtotal on commodity - utility	(187,994)	35,783	(42,616)
Net gain (loss) on foreign currency forward purchases - utility	88	(728)	662
Total realized net gain (loss)	$(187,906)	$35,055	$(41,954)

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 other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, and are offset by a corresponding balance in non-trading derivative assets or liabilities (see Note 10).

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. Only the two qualified defined benefit pension plans 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 for non-union employees and for union employees, respectively, were closed to new participants. Instead, non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, 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.

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 7). These key assumptions have a significant impact on the pension amounts recorded and disclosed. Retirement benefit costs consist of service costs, interest costs, the amortization of actuarial gains, losses and prior service costs, the expected returns on plan assets and, in part, on a market-related valuation of assets, if applicable. The market-related asset valuation reflects differences between expected returns and actual investment returns, which we recognize over a three-year period or less from the year in which they occur, thereby reducing year-to-year volatility in retirement benefit costs.

Accounting standards also require balance sheet recognition of the overfunded or underfunded status of pension and postretirement benefit plans in 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 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 1, "Industry Regulation").

Table of Contents

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, 2009 measurement date, we reviewed and updated:

- our pension and postretirement weighted-average discount rate assumptions from 6.60 percent to 6.01 percent and from 7.12 percent to 5.78 percent, respectively. The new rate assumptions were determined for each plan based on a matching of the estimated cash flow, which reflects the timing and amount of future benefit payments, to 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 changed from a range of 3.5 to 5.0 percent to a range of 3.25 to 5.0 percent;
- our expected long-term return on qualified defined benefit plan assets remained unchanged at 8.25 percent; and
- other key assumptions as needed based on actual experience and actuarial recommendations.

At December 31, 2009, our net pension liability (benefit obligations less market value of plan assets) for the two qualified defined benefit plans decreased by $10.5 million compared to 2008. Better than expected investment performance plus a cash contribution of $25 million more than offset the $19.0 million increase in benefit obligations due to lower discount rates and $4.2 million increase due to updating other assumptions, thereby resulting in the net decrease to our unfunded pension liability. The liability for non-qualified plans increased $3.1 million and the liability for other postretirement benefits increased $1.8 million in 2009.

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, 2009, the actual annualized returns on plan assets, net of management fees, for the past one-year, five-years, 10-years and since December 1980 were 15.79 percent, 2.23 percent, 2.96 percent and 10.29 percent, respectively.

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

Thousands, except percent	Change in Assumption	Impact on 2009 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2009
Discount rate:	(0.25 %)		
Qualified defined benefit plans		$ 862	$ 8,604
Non-qualified plans		7	3,212
Other postretirement benefits		100	558
Expected long-term return on plan assets:	(0.25 %)		
Qualified defined benefit plans		550	N/A

The impact of a change in retirement benefit costs on operating results would be less than the amounts shown above because only between 60 and 70 percent of our pension costs is charged to operations and maintenance expense. The remaining 30 to 40 percent is capitalized to construction accounts as payroll overhead and included in utility plant, which is amortized to expense over the useful life of the asset placed into service.

Table of Contents

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, 2009 and 2008, our net long-term deferred tax liability totaled $300.9 million and $257.8 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, 2009, we did not have a valuation allowance due to our expectation that all of these assets 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, 2009 and 2008, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $76.2 million and $69.9 million, respectively, and recorded an offsetting deferred tax liability (see Note 1, “Income Tax Expense”). We received authorization from the OPUC and WUTC in 2008 to accelerate the recovery of these pre-1981 regulatory assets through future utility rates (see “Regulatory Accounting,” above, and Notes 1 and 8).

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, 2009, we had no uncertain tax positions.

The Internal Revenue Service (IRS) is currently examining our 2006 through 2008 consolidated federal income tax returns. The IRS completed its last examination of the 2002 through 2004 audit cycle in the second quarter of 2006. Completion of the 2006 through 2008 federal income tax returns is expected during 2010.

Interest and penalties, if any, related to any future income tax deficiencies will be recorded within income tax expense in the consolidated statements of income.

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 defense 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 recently completed studies and negotiations involving several sites. 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 $65.3 million as of December 31, 2009. 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, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. Therefore, we have recorded the liabilities at an amount that reflects the most likely estimate or the low end of the range.

Table of Contents

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 11).

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates and systems of accounts by the OPUC, the WUTC, FERC, and with respect to Gill Ranch, the CPUC. The OPUC and WUTC and, with respect to Gill Ranch, the CPUC, also regulate our issuance of securities. In 2009, 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. Future earnings and cash flows from utility operations will be determined largely by the Oregon and Washington economies in general, and 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, operating and maintenance costs and investments made in utility plant.

General Rate Cases

Oregon. In our most recent general rate increase in Oregon, which was effective in September 2003, the OPUC authorized rates to customers based on a return on common stock equity (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 restricts us from filing a general rate case with the OPUC prior to September 1, 2011, subject to certain exceptions. Under the agreement, we would be allowed to file a general rate case if an extraordinary event occurs or significant investments are required on behalf of our customers and we are unable to reach agreement regarding alternative forms of cost recovery outside of a general rate case. These exceptions might include additional investments in our pipeline integrity management program. This agreement does not impact our ability to file annual rate adjustments to reflect changes in gas purchase costs under our PGA mechanism or our ability to collect or refund prior year’s gas cost deferrals. See “Rate Mechanisms—Purchased Gas Adjustment,” below.

Washington. In December 2008, an all-party stipulated agreement regarding our Washington general rate case was approved by the WUTC. As part of the stipulation, the WUTC authorized rates to our customers based on a ROE of 10.1 percent, which is included as part of an overall rate of return on total invested capital of 8.4 percent. These new customer rates went into effect on January 1, 2009. Under these rates, our annual revenue requirements increased by approximately $2.7 million, or 3 percent. We are reviewing recent decisions regarding decoupling mechanisms in Washington and considering whether to request approval for a decoupling mechanism.

Federal. We are required under our Mist interstate storage certificate authority and rate approval orders to file every three 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. We filed a cost and revenue study and an associated petition for rate approval 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 in August 2008, with our maximum rates unchanged from the levels approved by FERC in 2005. The maximum cost-based rates are designed to reflect updated costs related to the further development of the Mist gas storage facility from 2005 to 2008. Additionally, 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 to match the depreciation rates for the same assets that were recently adjusted under state regulation. We did not file to make any changes to the previously approved maximum rates. 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, 2011.

California. To date, we have not filed any rate cases or storage service tariffs with the CPUC. Later in 2010, we expect to file a storage service tariff with the CPUC with respect to Gill Ranch.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including gas storage, gas purchases hedged with financial derivatives, interstate pipeline demand charges, 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 2009, the OPUC and WUTC approved rate changes effective on November 1, 2009 under our PGA mechanisms. The effect of the rate changes was to decrease the average monthly bills of Oregon residential customers by 18 percent, partially offset by an increase in the public purpose charge, which resulted in a net decrease of 16 percent. The average monthly bills of Washington residential customers decreased by 22 percent.

Under the current Oregon PGA incentive sharing mechanism, we are required to select by August 1 of each year either an 80 percent deferral or 90 percent deferral of higher or lower actual gas costs compared to PGA prices such that the impact on current earnings from the gas cost incentive sharing is either 20 percent or 10 percent, respectively. In addition to the gas cost incentive sharing mechanism, we are also subject to an annual earnings review to determine if the utility is earning over an allowed threshold. If utility earnings exceed a specific earnings threshold level, then 33 percent of the amount above the threshold will 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 80 percent deferral option for the 2008-2009 PGA year. In August 2009, we selected 90 percent deferral for the 2009-2010 PGA year. The earnings threshold is subject to adjustment up or down depending on movements in long-term interest rates. In 2009 and 2008, the earnings threshold after adjustment for long-term interest rates was 11.5 percent and 13.1 percent, respectively. No amounts were required to be refunded to customers as a result of the 2008 utility earnings review, and we do not expect that any amounts will be required to be refunded to customers as a result of the 2009 earnings review, which will be approved by the OPUC during the second quarter of 2010.

There has been no change to the Washington PGA mechanism under which we defer 100 percent of the higher or lower actual purchased gas costs and pass that difference through to customers as an adjustment to future rates. We do not have an earnings sharing mechanism in Washington.

Conservation Tariff. In October 2002, the OPUC authorized the implementation of a “conservation tariff,” which is a rate mechanism designed to adjust margin for changes in consumption patterns due to residential and commercial customers’ conservation efforts. The 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’ conservation efforts. In Washington, customer use is not covered by a conservation 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 revenues.

The Oregon conservation tariff includes two components: (1) a price elasticity adjustment, which adjusts rates annually for increases or decreases from expected customer volumes due to annual changes in commodity costs or periodic changes in our general rates; and (2) a conservation adjustment calculated on a monthly basis 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 year's 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. See "Results of Operations—Business Segments - Utility Operations," below.

Table of Contents

In 2005, an independent study to measure the effectiveness of Oregon's conservation tariff mechanism recommended continuation of the tariff with minor modifications, which the OPUC approved. In September 2007, the OPUC extended our conservation tariff through October 2012.

Weather Normalization. In Oregon, the OPUC approved our use of a weather normalization mechanism through October 2012. 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 our residential and commercial customers' 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). We do not have a weather normalization mechanism approved for our Washington customers, which account for about 10 percent of our utility revenues.

Regulatory and Insurance Recovery for Environmental Costs. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue interest 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. These authorizations have been extended through January 2010. We have requested another extension through January 2011, and that request is currently pending. See Note 11.

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

System Integrity Program. In 2004, the OPUC approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program, a program mandated by the Pipeline Safety Improvement Act of 2002 and the related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). We record these costs as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period ending September 30, and recover the revenue requirement associated with the costs, subject to audit, through rate changes effective with the annual PGA in Oregon. The PHMSA also had proposed a distribution integrity management program. In February 2009, the OPUC approved a stipulated agreement to create a new, consolidated system integrity program (SIP). The SIP integrates the existing transmission pipeline and proposed distribution pipeline integrity management programs into a single program. In December 2009, the PHMSA issued the final rule for distribution integrity management programs. 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 and other interested parties.

The SIP allows recovery of costs incurred, as discussed above, in Oregon during the period from October 2008 through October 2011, or until the effective date of new rates adopted in our next general rate case. We do not have any special accounting or rate treatment for SIP costs incurred in the state of Washington.

AMR Deferral. In 2009, we completed a project to automate the reading of our Oregon customers' gas meters. The capital cost of this AMR project was approximately $25 million. In February 2010, the OPUC approved a stipulation that allows us to defer the revenue requirement associated with the AMR project and amortize that deferral subject to an annual earnings test. We are permitted to recover the deferral amount as long as our ROE during the earnings review period does not exceed our authorized ROE. Earnings or losses from our PGA gas cost incentive sharing mechanism are not included for purposes of this earnings test. Recovery of any deferred amounts will begin in November 2010 as part of our annual PGA rate adjustment.

Depreciation Study. The OPUC and WUTC approved our filed depreciation study and our request to change the amortization of our regulatory tax asset account balance on pre-1981 plant. These approvals specifically authorized the implementation of new depreciation rates in Oregon and Washington, with a corresponding decrease to customer billing rates effective January 1, 2009 (see "Consolidated Operations—Depreciation and Amortization," below). The new regulatory tax amortization schedule on pre-1981 assets, with a corresponding increase to customer rates, became effective January 1, 2009 in Washington and November 1, 2009 in Oregon. The implementation of the new rates decreases depreciation expense and increases income tax expense, both of which are offset on an annualized basis by a corresponding change in utility operating revenues. FERC also approved the application of these new depreciation rates for our interstate gas storage assets in May 2009, and the new rates were made effective as of January 1, 2009.

Customer Refunds for Gas Cost Incentive Sharing. For the period between November 1, 2008 and March 31, 2009, our actual gas costs were significantly lower than the gas costs embedded in customer rates. As a result, 80 percent of the gas cost savings attributed to Oregon and 100 percent of the savings attributed to Washington were recorded to a regulatory account for refund to customers (see "Purchased Gas Adjustment," above). Ordinarily, these refunds would be included in customer rates in the next year's PGA filing, but in 2009 we received special regulatory approval to refund the accumulated gas cost savings early to our Oregon and Washington customers. In June and July 2009, we refunded a total of $31.5 million to our Oregon customers and $4.3 million to our Washington customers through billing credits.

Pension Deferral. We are currently subject to a regulatory deferral order from the OPUC whereby we must refund cost savings to customers when our annual pension expense is below the amount set for rate recovery in our last general rate case. However, we are currently not authorized to defer and recover any cost increases from customers when our annual pension expense is above the amount set in rates. For 2010, our annual pension expense is expected to be significantly above the amount set in rates, and we may seek some form of regulatory relief for pension expenses between now and our next general rate case.

Business Segments - Utility Operations

Our utility margin results are affected by customer growth and to a certain extent by changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff that adjusts revenues to offset changes in margin resulting from increases or decreases in residential and commercial customer consumption. We also have a weather normalization mechanism that adjusts customer bills up or down 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 mechanisms are designed to reduce the volatility of our utility earnings.

2009 compared to 2008:

Our utility segment in 2009 earned $66.0 million, or $2.48 per share, compared to $58.7 million, or $2.21 per share in 2008. The major factor contributing to the increase in utility margin was a $20.6 million increase in our gas cost incentive sharing from lower gas prices. Total utility volumes sold and delivered in 2009 decreased by 10 percent over last year due to the effects of warmer weather on residential and commercial use and the effects of a weak economy on commercial and industrial use. Margin was reduced by $11.4 million in 2009 compared to 2008 due to a customer rate decrease which corresponded to a decrease in depreciation rates and expense effective January 1, 2009. Excluding the impact of lower depreciation rates on revenues, our margin from residential and commercial customers increased by $5.2 million in 2009, including the effects of the weather normalization and decoupling mechanisms. Industrial margin declined $2.1 million, but would have decreased by $1.3 million if the depreciation rate impact was excluded. The regulatory adjustment for income taxes paid also increased margin by $4.1 million compared to 2008, primarily due to the cost of gas savings in 2009.

Our weather normalization mechanism reduced residential and commercial margin by $15.2 million for the year ended December 31, 2009 based on weather that was 3 percent colder than average, compared to a reduction of $15.3 million for the year ended December 31, 2008 when weather was 7 percent colder than average. Our decoupling mechanism increased residential and commercial margin by $11.6 million in 2009, after adjusting for expected price elasticity impacts from higher PGA prices effective November 1, 2008, compared to a margin increase of $4.9 million in 2008.

2008 compared to 2007:

Our utility segment in 2008 earned $58.7 million, or $2.21 per share, compared to $64.9 million, or $2.41 per share in 2007. This decrease is primarily due to a decrease in utility margin of $14.3 million or 4 percent even though margins from residential and commercial customers contributed an additional $7.1 million in 2008, including the effects of the weather normalization and decoupling mechanisms while margin from industrial customers declined by $1.6 million. Total utility volumes sold and delivered in 2008 increased by 4 percent over 2007 due to colder weather and 1.6 percent customer growth. The major factors contributing to the decline in utility margin were the $17.6 million decrease in our regulatory incentive sharing from higher gas costs, a $4.2 million decrease in the regulatory adjustments for income taxes paid and a $1.6 million decrease in margin from industrial customers due to weak economic conditions.

Table of Contents

Our weather normalization mechanism offset residential and commercial margin gains by $15.3 million for the year ended December 31, 2008 based on weather that was 7 percent colder than average, compared to an offset of $2.5 million for the year ended December 31, 2007, based on weather that was 3 percent colder than average in 2007. Our decoupling mechanism recovered $4.9 million of residential and commercial margin losses in 2008, after adjusting for expected price elasticity impacts from higher PGA prices effective November 1, 2007, compared to a margin recovery of $0.5 million in 2008.

The following table summarizes the composition of gas utility volumes and revenues for the years ended December 31, 2009, 2008 and 2007:

Thousands except degree day and customer data	2009	2008	2007	Favorable/(Unfavorable) 2009 vs. 2008	2008 vs. 2007
Utility volumes - therms:					
Residential sales	412,867	428,787	398,960	(15,920)	29,827
Commercial sales	255,593	265,531	249,659	(9,938)	15,872
Industrial - firm sales	39,447	47,340	52,340	(7,893)	(5,000)
Industrial - firm transportation	124,218	184,832	161,790	(60,614)	23,042
Industrial - interruptible sales	72,525	87,484	89,128	(14,959)	(1,644)
Industrial - interruptible transportation	226,715	246,777	263,092	(20,062)	(16,315)
Total utility volumes sold and delivered	1,131,365	1,260,751	1,214,969	(129,386)	45,782
Utility operating revenues - dollars:					
Residential sales	$555,844	$566,840	$555,312	$(10,996)	$11,528
Commercial sales	292,697	298,943	298,800	(6,246)	143
Industrial - firm sales	41,407	46,579	54,567	(5,172)	(7,988)
Industrial - firm transportation	5,671	6,370	5,927	(699)	443
Industrial - interruptible sales	62,116	68,978	74,876	(6,862)	(5,898)
Industrial - interruptible transportation	7,964	7,918	8,264	46	(346)
Regulatory adjustment for income taxes paid (1)	5,884	1,760	5,996	4,124	(4,236)
Other revenues	21,166	21,784	12,228	(618)	9,556
Total utility operating revenues	992,749	1,019,172	1,015,970	(26,423)	3,202
Cost of gas sold	611,088	656,504	639,094	45,416	(17,410)
Revenue taxes	24,656	25,072	25,001	416	(71)
Utility net operating revenues (utility margin)	$357,005	$337,596	$351,875	$19,409	$(14,279)
Utility margin: (2)					
Residential sales	$217,124	$224,683	$213,698	$(7,559)	$10,985
Commercial sales	85,850	90,402	85,960	(4,552)	4,442
Industrial - sales and transportation	27,713	29,771	31,333	(2,058)	(1,562)
Miscellaneous revenues	6,670	6,381	4,966	289	1,415
Regulatory share of gas cost	15,064	(5,505)	12,135	20,569	(17,640)
Other margin adjustments	2,308	436	(229)	1,872	665
Margin before regulatory adjustments	354,729	346,168	347,863	8,561	(1,695)
Weather normalization mechanism	(15,236)	(15,266)	(2,496)	30	(12,770)
Decoupling mechanism	11,628	4,934	512	6,694	4,422
Regulatory adjustment for income taxes paid (1)	5,884	1,760	5,996	4,124	(4,236)
Utility margin	$357,005	$337,596	$351,875	$19,409	$(14,279)

Customers - end of period:					
Residential customers	604,692	599,285	589,676	5,407	9,609
Commercial customers	62,169	62,115	61,397	54	718
Industrial customers	933	941	939	(8)	2
Total number of customers - end of period	667,794	662,341	652,012	5,453	10,329
Actual degree days	4,383	4,576	4,374		
Percent colder (warmer) than average (3)	3 %	7 %	3 %		

(1) See "Regulatory Adjustment for Income Taxes Paid," below for further discussion.
(2) Amounts reported as margin for each category of customers are net of demand charges and revenue taxes.
(3) Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

Table of Contents

In June and July 2009, we refunded gas cost savings totaling $35.8 million to our Oregon and Washington customers. The following non-GAAP table summarizes the impact of this refund on our operating revenues, cost of gas sold and margin for the year ended December 31, 2009, along with a comparison to the years ended December 31, 2008 and 2007. We believe this non-GAAP financial calculation enables the reader of the financial statements to better understand our operating revenues, cost of gas and utility margin performance from management's perspective in addition to the traditional GAAP presentation.

	2009				
Thousands	As Reported	Refund	Excluding Refund (Non-GAAP)	2008	2007
Utility operating revenues:					
Residential sales	$555,844	$19,952	$ 575,796	$566,840	$555,312
Commercial sales	292,697	11,579	304,276	298,943	298,800
Industrial - firm sales	41,407	1,585	42,992	46,579	54,567
Industrial - firm transportation	5,671	-	5,671	6,370	5,927
Industrial - interruptible sales	62,116	2,673	64,789	68,978	74,876
Industrial - interruptible transportation	7,964	-	7,964	7,918	8,264
Regulatory adjustment for income taxes paid	5,884	-	5,884	1,760	5,996
Other revenue	21,166	-	21,166	21,784	12,228
Total utility operating revenues	992,749	35,789	1,028,538	1,019,172	1,015,970
Cost of gas sold	611,088	34,691	645,779	656,504	639,094
Revenue taxes	24,656	898	25,554	25,072	25,001
Utility margin	$357,005	$200	$ 357,205	$337,596	$351,875

The non-GAAP information disclosed above reconciles to the preceding table summarizing utility margin for the year ended December 31, 2009.

Residential and Commercial Sales

Residential and commercial sales are impacted by 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. This mechanism is effective for the period from December 1 through May 15 of each heating season. Approximately 9 percent of our eligible Oregon customers have opted out of the mechanism. In Oregon, we also have a conservation decoupling mechanism that is intended to break the link between our earnings and the quantity of gas consumed by customers, so that we do not have an incentive to encourage greater consumption and undermine Oregon's conservation policy and efforts. In Washington, where the remaining 10 percent of our customers are served, we do not have a weather normalization or a conservation decoupling mechanism. As a result, we are not fully insulated from earnings volatility due to weather and conservation in Washington.

The primary factors that impact results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, competition from other energy sources, economic conditions and to a certain extent the volatility of gas prices.

2009 compared to 2008:

- operating revenues in 2009 decreased $17.2 million or 2 percent primarily due to $31.5 million in customer refunds for gas cost savings, partially offset by customer rate increases of 14 and 21 percent in Oregon and Washington, respectively, effective November 1, 2008, and customer growth of 0.8 percent;
- volumes were 4 percent lower, primarily reflecting 4 percent warmer weather, customer conservation and weak economic conditions; and
- sales margin was 4 percent lower due to lower volumes and customer rate decreases related to lower depreciation expense, but that was partially offset by the decoupling adjustment that recovers margin from lower use per customer.

Table of Contents

2008 compared to 2007:

- operating revenues in 2008 increased 1 percent on a 7 percent increase in volumes due to 5 percent colder weather and 1.6 percent customer growth, partially offset by customer rate decreases of 8 to 10 percent over the first 10 months of 2008; and
- sales margin was 5 percent higher, reflecting increased volumes from customer growth and from colder weather, but that was largely offset by the weather normalization adjustment that credits customer bills when weather is colder than normal.

Industrial Sales and Transportation

Industrial operating revenues include the commodity cost component of gas sold under sales service but not under transportation service. Therefore, industrial customer switching between sales service and transportation service can cause swings in operating revenues but generally our margins are unaffected because we do not mark up the cost of gas. As such, we believe margin is a better measure of performance for the industrial sector. The primary factors that impact margin from industrial sales and transportation markets are as follows:

2009 compared to 2008:

- volumes delivered to industrial customers decreased 104 million therms, or 18 percent, reflecting reduced usage likely due to weak economic conditions; and
- margin decreased $2.1 million, or 7 percent, reflecting a weak economy and customer rate decreases related to lower depreciation expense and lower volumes, but that was partially offset by fixed charges not affected by declining use.

2008 compared to 2007:

- volumes delivered to industrial customers increased 0.1 million therms, or less than 1 percent, reflecting a reduction in sales volumes of 6.6 million therms offset by an increase in transportation volumes of 6.7 million therms; and
- margin decreased $1.6 million, or 5 percent, reflecting a shift from higher margin to lower margin rate schedules, but this decrease was partially offset by a margin gain of $0.8 million from curtailment charges assessed to a small number of customers who were out of compliance during a cold weather episode in December 2008.

Several large industrial customers transferred from sales service to transportation service in 2009 and 2008. Changes in natural gas prices can result in a number of our large industrial customers switching between transportation service, where they arrange for their own supplies through independent third parties, to sales service, where we sell them the gas commodity under regulatory tariffs. In such cases, our tariff requires us to charge the incremental cost of gas supply incurred, if any, to serve those customers so that the cost does not adversely impact our margins or the prices our core customers pay.

Regulatory Adjustment for Income Taxes Paid

Oregon law requires regulated natural gas and electric utilities to annually review the amount of income taxes collected in rates from utility operation and compare it to the amount the utility actually pays to taxing authorities. Under this law, if we pay less in income taxes than we collect from our Oregon utility customers, or if our consolidated taxes paid are less than the taxes we collect from our Oregon utility customers, then we are required to refund the excess to our Oregon utility customers. Conversely, if we pay more income taxes than we actually collect from our Oregon utility customers, as set forth under our most recent general rate case, then we are required to collect a surcharge from our Oregon utility customers.

- 44-

Table of Contents

For the 2007 and 2008 tax years, the OPUC approved our tax filings to recover $6.4 million and $0.2 million, respectively, through a surcharge to our Oregon utility customers. It was agreed that the 2007 surcharge, plus accrued interest, would be collected in a one-time charge to customers in June 2009. It was also agreed that the 2008 surcharge, plus accrued interest, would be collected over a one-year period beginning June 1, 2010. For the 2009 tax year, we anticipate that the difference between income taxes paid and the amounts collected in rates will be greater than $100,000, and in accordance with the rules, we have estimated a surcharge of $5.3 million (excluding interest). Both the 2007 and 2009 surcharges were primarily driven by higher income taxes paid on gains from gas cost savings from our PGA incentive sharing mechanism. The following table summarizes the total adjustment for income taxes paid as recognized in our results of operations for the year ended December 31, 2009:

Thousands	Surcharge	Interest	Total
Tax Year 2007	$ -	$ 225	$ 225
Tax Year 2008	179	23	202
Tax Year 2009	5,265	192	5,457
Total adjustment for income taxes paid	$5,444	$440	$5,884

Other Revenues

Other revenues include miscellaneous fee income as well as revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferrals relating to gas costs. Other revenues increased net operating revenues by $21.1 million in 2009, compared to $21.8 million in 2008 and $12.2 million in 2007.

2009 compared to 2008:

Other revenues in 2009 were $0.7 million lower than in 2008 primarily reflecting a $6.3 million surcharge for the rate adjustment from income taxes paid and $0.7 million decrease in curtailment charges, partially offset by a $7.4 million refund to utility customers related to the gas storage regulatory sharing mechanism.

2008 compared to 2007:

Other revenues in 2008 were $9.6 million higher than in 2007 primarily reflecting a $10.5 million refund to utility customers related to the gas storage regulatory sharing mechanism, partially offset by a $1.9 million surcharge for the rate adjustment from income taxes paid.

Cost of Gas Sold

The cost of gas sold includes current gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use. Our regulated utility does not generally earn a profit or incur a loss on gas commodity purchases. The OPUC and the WUTC require the natural gas commodity cost to be billed to customers at the same cost incurred or expected to be incurred by the utility. However, under the PGA mechanism in Oregon, our net income is affected by differences between actual and expected purchased gas costs primarily due to market fluctuations and volatility affecting unhedged purchases (see "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above). We use natural gas 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 as the hedges are usually 100 percent passed through to customers in annual rate changes, subject to a regulatory prudency review. However, utility gas hedges entered into after the annual PGA filing in Oregon may impact net income to the extent of our share of any gain or loss under the PGA. In Washington, 100 percent of the actual gas costs, including hedge gains and losses, are passed through in customer rates (see “Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities,” and “Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment,” above, and Note 11).

2009 compared to 2008:

- total cost of gas sold decreased $45.4 million, or 7 percent, primarily due to reduced sales volumes and credits for customer refunds;
- the average gas cost collected through rates decreased 1 percent from 79 cents per therm in 2008 to 78 cents per therm in 2009, primarily reflecting the reduction to cost of gas sold from our customer refund in 2009, partially offset by our 14 to 21 percent PGA rate increases effective November 1, 2008; and
- net losses totaling $187.9 million were realized from our financial hedges and included in cost of gas sold, compared to $35.1 million of net hedge gains in 2008.

2008 compared to 2007:

- total cost of gas sold increased $17.4 million or 3 percent, due to increased sales volumes;
- the average cost of gas sold decreased 2 percent from 81 cents per therm in 2007 to 79 cents in 2008, primarily reflecting our 8 to 10 percent PGA rate decreases effective November 1, 2007 and our 14 to 21 percent increases effective November 1, 2008; and
- net gains of $35.1 million were realized from our financial hedges and included in cost of gas sold, compared to $42.0 million of net losses in 2007.

In 2009 and 2007, our actual gas costs were significantly lower than gas costs embedded in rates, but in 2008 our actual gas costs were higher than the gas costs embedded in rates. The effect on shareholders from the gas cost incentive sharing mechanism was a margin gain of $15.1 million and $12.1 million in 2009 and 2007, respectively, compared to a margin loss of $5.5 million in 2008. For a discussion of our Oregon gas cost incentive sharing mechanism and the change effective November 1, 2009, see “Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment,” above.

Business Segments Other than Utility Operations

Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility, utility and non-utility asset optimization and Gill Ranch. In 2009, we earned $8.9 million, or 34 cents per share, from our gas storage business segment, after regulatory sharing and income taxes. This compares to net income of $8.4 million, or 31 cents per share, in 2008 and $8.5 million, or 32 cents per share, in 2007.

In Oregon, we retain 80 percent of the pre-tax income from gas storage services as well as from optimization services when the costs of the capacity being used is not included in utility rates, or 33 percent of the pre-tax income from such storage and optimization 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 refund to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage and optimization services.

In 2007, we announced a joint project with PG&E to develop a new underground natural gas storage facility at Gill Ranch near Fresno, California. We formed a subsidiary of NW Natural to develop and operate the facility. Gill Ranch will initially own 75 percent of the project, and PG&E will own 25 percent. As of December 31, 2009 and 2008, total assets at Gill Ranch were $116.3 million and $13.2 million, respectively. See Note 2.

Other

Our other business segment consists of Financial Corporation, an equity investment in Palomar and other non-utility investments and business activities. Financial Corporation had total assets at December 31, 2009 and 2008 of $1.4 million and $1.3 million, respectively, and our investment balance in Palomar was $14.1 million and $14.2 million, respectively. The asset balance at Financial Corporation reflects a non-controlling interest in the Kelso Beaver pipeline. The balance in Palomar reflects our equity investment to date in a proposed 217-mile transmission pipeline.

Net income from our other business segment for the years ended December 31, 2009, 2008 and 2007 was $0.2 million, $2.4 million and $1.1 million, respectively. In 2008, we sold the last of our non-core assets, resulting in an after-tax gain of $1.1 million. See Note 2.

Table of Contents

Consolidated Operations

Operations and Maintenance

Operations and maintenance expenses increased by $13.7 million in 2009, or 12 percent higher than 2008, while 2008 was $7.1 million, or 6 percent lower than 2007. In 2009, operations and maintenance expense included increased costs for pensions, health care, bonuses and a severance program. The following summarizes the major factors that contributed to changes in operations and maintenance expense:

2009 compared to 2008:

- an $8.0 million increase in pension expense primarily due to lower assumed discount rates and a decrease in our plans' funded status, which resulted from a significant decline in the market value of assets during 2008;
- a $5.3 million increase in employee labor and benefit expense due to higher health care premiums and higher bonuses related to above-target operating results, which affect annual incentive payments and compensation;
- a $1.1 million charge related to our voluntary severance program involving workforce reductions during the third and fourth quarters of 2009;
- a $1.1 million increase in strategic initiatives including performance improvement and corporate tax projects; and
- a $1.0 million increase in utility uncollectible expense (see discussion below).

Partially offsetting the above increases were:

- a $2.1 million decrease in employee compensation expense related to reduced employee count; and
- a $0.6 million decrease in claims in 2009.

2008 compared to 2007:

- a $4.3 million decrease due to additional costs incurred in 2007 for strategic initiatives including maintenance projects, training and promotional and safety campaigns; and
- a $5.6 million decrease in employee compensation and benefit expense, primarily due to lower bonuses related to lower operating results which affected annual and long-term incentives.

Partially offsetting the above decreases were:

- a $2.0 million increase in costs related to serving a growing customer base and increased operating expenses during the December cold weather episode; and
- a $0.2 million, or 6 percent, increase in uncollectible expense reflecting higher revenues due to rate increases and sales volume increases.

Our bad debt expense ratio as a percent of revenues was 0.42 percent for 2009, compared to 0.31 percent in 2008. Due to the weak economy and high unemployment rates, we were seeing a slight increase in delinquent balances and customers on payment plans, partially offset by an increase in low income energy assistance funds available for customers and refunds of gas cost savings in June and July of 2009. Also, we have a rate mechanism that covers the increase in bad debt expense directly related to increases in commodity costs. Under our PGA mechanism, billing rates are adjusted each year to recover the expected increase (or decrease) in bad debt expense due to the higher cost of natural gas. The revenue adjustment for bad debt expense is based on our average write-off rate over the last three years multiplied by the estimated increase in commodity costs. In 2009, margin revenues increased by approximately $0.6 million to partially offset the expected increase in bad debt expense.

Table of Contents

General Taxes

General taxes, which are principally comprised of property and payroll taxes and regulatory fees, increased $1.6 million, or 6 percent, in 2009 compared to 2008, and increased $1.4 million, or 5 percent, in 2008 compared to 2007. The major factors that contributed to changes in general taxes are:

2009 compared to 2008:

- a $1.0 million, or 5 percent increase in property taxes related to a 3 percent increase in utility plant balances; and
- a $0.5 million increase in payroll taxes due to higher incentive compensation and employee severance compensation in 2009.

2008 compared to 2007:

- a $1.3 million increase in property taxes related to higher tax rates and increased utility plant balances.

We have been involved in litigation with the Oregon Department of Revenue (ODOR) over whether natural gas inventories and appliance inventories held for resale are required to be taxed as personal property. This was appealed to and presented before the Oregon Supreme Court in 2009. In January 2010, the Oregon Supreme Court unanimously ruled in our favor, stating that these inventories were exempt from property tax. The ODOR has until March 11, 2010 to file a Motion for Reconsideration with the Oregon Supreme Court. We are entitled to a refund of approximately $5.0 million, plus accrued interest, for property taxes paid on gas inventories beginning with the 2002-03 tax year and appliance inventories beginning with the 2005-06 tax year. We will recognize this gain as income in 2010.

Table of Contents

Depreciation and Amortization

The following table summarizes the increases in total plant and property and total depreciation and amortization for the three years ended December 31:

Thousands, except percentages	2009	2008	2007
Plant and property:			
Utility plant:			
Depreciable	$2,169,922	$2,101,900	$2,013,191
Non-depreciable, including construction work in progress	46,190	41,088	38,970
	2,216,112	2,142,988	2,052,161
Non-utility property:			
Depreciable	63,564	62,882	56,444
Non-depreciable, including construction work in progress	83,058	11,624	10,705
	146,622	74,506	67,149
Total plant and property	$2,362,734	$2,217,494	$2,119,310
Depreciation and amortization:			
Utility plant	$61,472	$70,691	$67,410
Non-utility property	1,342	1,468	933
Total depreciation and amortization expense	$62,814	$72,159	$68,343
Weighted average depreciation rate - utility	2.9 %	3.4 %	3.4 %
Weighted average depreciation rate - non-utility	2.2 %	2.5 %	2.1 %

Total depreciation and amortization expense in 2009 decreased by $9.3 million, or 13 percent, as compared to a $3.8 million or 6 percent increase, in 2008 over 2007. The decreased expense in 2009 was related to the adoption of the new depreciation rates, which were approved by the OPUC, WUTC and FERC effective January 1, 2009 (see "Regulatory Matters—Rate Mechanisms—Depreciation Study," above). The increased expense in 2008 was primarily due to additional investments in utility plant to meet continuing customer growth and to make system improvements (see "Financial Condition—Cash Flows—Investing Activities," below, and Note 9).

Other Income and Expense – Net

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

Thousands	2009	2008	2007
Gains from company-owned life insurance	$3,416	$2,190	$1,939
Interest income	211	250	537
Income from equity investments	1,329	667	130
Net interest on deferred regulatory accounts	2,051	552	84
Gain on sale of investments	45	1,737	1,544
Other non-operating	(3,338)	(1,650)	(2,789)
Total other income and expense - net	$3,714	$3,746	$1,445

2009 compared to 2008:

Other income and expense - net decreased by less than $0.1 million in 2009 over 2008. The decrease was primarily due to a net increase in other non-operating expense for higher business development costs and other strategic initiatives expense in 2009, and from the gain on sale of the aircraft in 2008. These were partially offset by increases in income from company-owned life insurance, income from our equity investment in Palomar and interest income from deferred regulatory account balances.

Table of Contents

2008 compared to 2007:

Other income and expense–net increased by $2.3 million in 2008 over 2007. The increase was primarily due to a decrease of $1.1 million in other non-operating expense, reflecting the additional start-up expenses in 2007 for business development and other strategic initiatives, and by a $0.2 million increase from the gain on sale of investments, reflecting the gains on sales of the aircraft in 2008 and the two wind power electric generation projects in 2007, and a $0.5 million increase in income from equity investments, primarily related to Palomar.

Interest Charges – Net of Amounts Capitalized

Interest charges-net of amounts capitalized in 2009 increased by $3.1 million, or 8 percent, compared to 2008, reflecting the issuance of long-term debt to refinance short-term debt balances, which included the issuance of $75 million of 5.37 percent medium-term notes (MTN's) issued in March 2009 and the $50 million of 3.95 percent MTN's issued in July 2009. Interest charges-net of amounts capitalized in 2008 decreased by $0.2 million, or less than 1 percent, compared to 2007, reflecting lower balances on long-term debt outstanding due to the redemption of $5 million of MTN's in July 2008. The average interest crediting rate for the allowance for funds used during construction, comprised of short-term and long-term borrowing rates, as appropriate, was 1.0 percent in 2009, 3.6 percent in 2008 and 5.4 percent in 2007.

Income Tax Expense

The increase in income tax expense of $6.0 million or 15 percent in 2009, compared to 2008 was primarily due to higher pre-tax consolidated earnings and a slightly higher effective tax rate of 38.3 percent in 2009 compared to 36.9 percent in 2008. Income tax expense decreased by $3.4 million or 8 percent in 2008, as compared to total income tax expense of $44.1 million in 2007, and the effective tax rate decreased slightly from an effective rate of 37.2 percent in 2007.

For the 2009 tax year, the higher effective tax rate was primarily the result of an increase in the Oregon corporate income tax rate (see below for further discussion), an increased amortization of our regulatory tax asset account on pre-1981 plant assets (see "Regulatory Matters—Rate Mechanisms—Depreciation Study," above), and an adjustment to deferred income taxes attributed to our non-regulated business segments. For the 2008 tax year, the slightly lower effective tax rate was primarily the result of a higher 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 1 and Note 8.

In July 2009, the governor of Oregon signed House Bill 3405 establishing increases in the state income tax rate for corporations. By referendum, Oregon voters approved this legislation in January 2010. The corporate income tax rate in Oregon for 2009 and 2010 will increase from 6.6 percent to 7.9 percent for corporations with taxable income over $250,000. For tax years 2011 and 2012, the income tax rate will decrease to 7.6 percent, and for years after 2012 the tax rate will return to the current 6.6 percent, except for corporations with taxable income over $10 million the tax rate will remain at 7.6 percent. The new tax rates are retroactive to January 1, 2009. Following existing 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. Approximately $3.5 million of the adjustment was attributed to our utility operations. As we anticipate future recovery in rates, we recorded a $5.8 million 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.

Table of Contents

Financial Condition

Capital Structure

Our goal 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 also are used to fund long-term debt redemption requirements and short-term commercial paper maturities (see "Liquidity and Capital Resources," below, and Notes 5 and 6). 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, 2009 and 2008:

	2009		2008	
Common stock equity	47.2	%	45.3	%
Long-term debt	43.0	%	36.8	%
Short-term debt, including current maturities of long-term debt	9.8	%	17.9	%
Total	100.0	%	100.0	%

Liquidity and Capital Resources

At December 31, 2009, we had $8.4 million of cash and cash equivalents compared to $6.9 million at December 31, 2008. Short-term liquidity is provided by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, unsecured credit facilities with multi-year commitments, (see "Credit Agreement," below), an ability to borrow from cash surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use long-term debt proceeds primarily to finance capital expenditures and refinance maturing short-term and long-term debt.

Our current senior secured long-term debt ratings are AA- from S&P and A1 from Moody's. Most recently, S&P downgraded our corporate credit rating to A+ from AA-, but at the same time reaffirmed our senior secured long-term debt rating at AA- and our senior unsecured rating at A+. Previously, Moody's had upgraded our long-term senior secured debt rating from A2 to A1 in August 2009. Our short-term debt ratings are A-1 from S&P and P-1 from Moody's. Both S&P and Moody's have assigned a stable outlook to our debt ratings.

Over the last 18 months, the capital markets have experienced significant volatility and tight credit conditions, but conditions have improved recently as reflected by tighter credit spreads and increased access to new financing for investment grade issuers. With our current debt ratings, we have been able to issue commercial paper and long term debt at attractive rates and have not needed to borrow from our $250 million back-up facility. In the event that we are not able to issue new debt due to market conditions, we expect that our near term liquidity needs can be met by using cash balances or drawing upon our committed credit facility (see "Credit Agreement," below). We also have a universal shelf registration statement filed with the Securities and Exchange Commission for the issuance of secured and unsecured debt or equity securities, subject to market conditions and regulatory approvals. We have OPUC approval to issue up to $175 million of additional MTNs under our shelf registration statement.

Our senior unsecured long-term debt ratings are A+ and A3 from S&P and Moody's, respectively. 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, 2009, we would be required to post approximately $7.8 million of collateral to our counterparties, but that would assume our long-term debt ratings were at non-investment grade levels, a level that is significantly lower than our current ratings.

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

Table of Contents

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 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. Our Board of Directors expects to continue paying cash dividends on common stock on a quarterly basis. However, the declarations and amount of future dividends will be dependent upon our earnings, cash flows, financial condition and other factors.

Off-Balance Sheet Arrangements

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

Contractual Obligations

The following table shows our contractual obligations at December 31, 2009 by maturity and type of obligation.

	Payments Due in Years Ending December 31,						
Thousands	2010	2011	2012	2013	2014	Thereafter	Total
Commercial paper	$ 102,000	$ -	$ -	$ -	$ -	$ -	$ 102,000
Long-term debt maturities	35,000	10,000	40,000	-	60,000	491,700	636,700
Interest on long-term debt	39,345	36,840	34,518	33,607	33,446	281,767	459,523
Postretirement benefit payments(1)	23,041	19,943	20,545	20,985	21,621	122,260	228,395
Capital leases	582	269	95	16	-	-	962
Operating leases	4,162	4,155	4,279	4,317	4,641	23,423	44,977
Gas purchase contracts(2)	145,305	37,819	23,640	16,741	13,951	-	237,456
Gas pipeline commitments	81,907	71,502	54,910	47,425	23,554	268,553	547,851
Other purchase commitments	130,339	7,183	813	-	-	-	138,335
Total	$ 561,681	$ 187,711	$ 178,800	$ 123,091	$ 157,213	$ 1,187,703	$ 2,396,199

(1) The majority of postretirement benefit payment obligations are related to our qualified defined benefit pension plans, which are funded by plan assets and future cash contributions. See Note 7.
(2) All gas purchase contracts use price formulas tied to monthly index prices. Commitment amounts are based on index prices at December 31, 2009.

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

At December 31, 2009, 646 of our utility employees were members of the Office and Professional Employees International Union, Local No. 11. In July 2009, our union employees ratified a new five-year labor agreement called the Joint Accord. The agreement included a 2.4 percent average wage increase effective June 1, 2009, and a scheduled 1 percent wage increase each year thereafter with the potential for up to an additional 2 percent per year based on wage inflation and other factors. The Joint Accord also maintains competitive health benefits while limiting the cost increases for these benefits to the same level as the annual wage increases, and provides increased job flexibility along with the ability for the Company to use short-term unpaid leave to temporarily adjust the workforce without layoffs. The Joint Accord continues our defined benefit retirement plan for existing employees, but closes the plan to new employees hired after December 31, 2009. 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.

Table of Contents

Short-term Debt

Our primary source of short-term liquidity is from internal cash flows and the sale of commercial paper notes. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas inventories and accounts receivable, short-term debt may be used to temporarily fund 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 Agreement,” 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 in 2008 and 2009. At December 31, 2009 and 2008, our utility had commercial paper outstanding of $69.8 million and $248.0 million, respectively. This year’s outstanding commercial paper balances were lower than last year’s primarily due to the refinancing of short-term debt with long-term debt issuances.

In March 2009, Gill Ranch entered into a cash collateralized credit facility for up to $40 million that has been extended until September 30, 2010. As of December 31, 2009, Gill Ranch had $32.2 million of borrowings outstanding included under short-term debt on the balance sheet, with a corresponding cash collateral amount included under restricted cash – current on the balance sheet. The effective interest rate on Gill Ranch’s credit facility is 0.8 percent.

Credit Agreement

We have a syndicated multi-year credit agreement for unsecured revolving loans totaling $250 million, which may be extended for additional one-year periods subject to lender approval. All lenders agreed to extend their obligations for an additional one-year period to May 31, 2013. All lenders under our credit agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2009 as follows:

Lender rating, by category		Amount Committed (in thousands)
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 seven lenders under the syndicated credit agreement, with commitments totaling $250 million, to May 31, 2013. The credit agreement also 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 maturity date of the credit agreement. The credit 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 credit agreement is due and payable on or before the maturity date. There were no outstanding balances under this credit agreement at December 31, 2009 and 2008. The 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, 2009 and 2008, with consolidated indebtedness to total capitalization ratios of 52.8 percent, and 54.7 percent, respectively.

Table of Contents

The syndicated credit 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 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- or Baa3 would require additional approval from the OPUC prior to issuance of debt, and interest rates on any loans outstanding under the credit agreement are tied to debt ratings, which would increase or decrease the cost of any loans under the credit agreement when ratings are changed (see "Credit Ratings," below).

Credit Ratings

The table below summarizes our current credit ratings from two rating agencies, S&P and Moody's.

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-1
Senior secured (long-term debt)	AA-	A1
Senior unsecured (long-term debt)	A+	A3
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 MTNs during 2009, 2008 and 2007 as follows:

Thousands	Redeemed in 2009	Redeemed in 2008	Redeemed in 2007
Medium-Term Notes:			
6.31% Series B due 2007	$-	$-	$20,000
6.80% Series B due 2007	-	-	9,500
6.50% Series B due 2008	-	5,000	-
6.65% Series B due 2027(1)	300	-	-

(1) In November 2009 one investor in our 6.65 percent secured MTNs due 2027 exercised its right under a one-time put option to redeem $0.3 million of the $20 million outstanding. This one-time put option has now expired, and the remaining $19.7 million principal outstanding is expected to be redeemed at maturity in November 2027.

Table of Contents

Cash Flows

Operating Activities

2009 compared to 2008:

Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements and other cash and non-cash adjustments to operating results. In 2009, cash flow from net income and operating activity adjustments, excluding working capital changes, increased $29.1 million compared to 2008. Working capital changes in 2009 increased $176.5 million compared to the same period in 2009. The overall change in cash flow from operating activities was an increase of $205.6 million. The significant factors contributing to the cash flow changes between 2009 and 2008 are as follows:

- an increase of $82.1 million from deferred gas cost savings reflecting lower actual gas prices compared to gas prices collected in customer rates in 2009, net of amounts already refunded to customers (see below);
- an increase of $72.0 million from decreases in accounts receivable and accrued unbilled revenue primarily due to the collection of higher balances in accounts receivable and accrued unbilled revenue balances at year end 2008;
- an increase of $41.6 million from income tax refunds received from a change in tax accounting method for certain repairs and maintenance costs (see below);
- an increase of $31.2 million related to the net decrease in gas inventory balances due to the higher price of gas injected into storage in 2008;
- an increase of $25.7 million from accounts payable, reflecting lower gas prices at the end of 2009 compared to 2008;
- a decrease of $25.0 million related to our pension contributions in 2009 to reduce our unfunded liability;
- a decrease of $13.4 million from deferred income taxes, reflecting the approved tax deduction for repair and maintenance costs (see below); and
- a decrease of $10.1 million related to the loss realized on the settlement of our interest rate hedge in 2009.

2008 compared to 2007:

In 2008, cash flow from net income and operating activity adjustments, excluding working capital changes, decreased $37.9 million compared to 2007. Working capital changes in 2008 decreased cash flow by $111.0 million compared to 2007. The majority of these working capital changes, particularly those related to accounts receivable, unbilled revenues inventories, income taxes receivable and accounts payable, reversed early in 2009 reflecting changes in seasonal working capital. The overall change in cash flow from operating activities in 2008 compared to 2007 was a decrease of $148.9 million. The significant factors contributing to the cash flow changes between 2008 and 2007 are as follows:

- an increase of $55.4 million in deferred income taxes and investment tax credits primarily from additional accelerated depreciation and a net operating loss (see Note 8);
- a decrease of $84.0 million in deferred gas costs, $30.4 million in accounts payable and $14.3 million in inventories, primarily due to the higher gas cost prices in 2008 compared to 2007;
- a decrease of $58.5 million in accounts receivable and accrued unbilled revenue due to the colder weather in December 2008 and our November 1, 2008 rate increase (see Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above); and
- a decrease of $20.8 million in income taxes receivable primarily due to bonus depreciation and an estimate for a future pension contribution, for which we saw an increase in deferred income taxes.

In June and July of 2009, we refunded an aggregate $35.8 million from a regulatory liability account to our Oregon and Washington customers for the customers' share of accumulated gas cost savings from November 1, 2008 through March 31, 2009. This reduction in cash was only part of the gas cost savings accumulated from lower gas prices during the 2008-09 gas contract year. Additional savings for customers have accumulated since March 31, 2009, and these amounts are being refunded to customers through lower rates starting November 1, 2009.

In December 2008, we filed an application with the IRS requesting a change in our tax accounting method to expense routine repair and maintenance costs for gas pipelines that are currently being capitalized and depreciated for book purposes. The IRS consented to our request in August 2009, and we recognized a tax deduction of approximately $59 million on our 2008 tax return, which resulted in a federal tax refund of approximately $21 million during the fourth quarter of 2009.

Table of Contents

At December 31, 2008, we reported an estimated net operating loss (NOL) for federal and Oregon income tax purposes of $19.2 million and $23.8 million, respectively, primarily due to the effects of accelerated tax depreciation provided by the Economic Stimulus Act. As a result of the change in our tax accounting method for repair and maintenance costs discussed above as well as our increased pension contribution, our NOL for federal and Oregon income tax purposes was $89.0 million and $87.2 million on our 2008 federal and Oregon tax returns, respectively. The federal NOL was carried back to 2006 for a refund of taxes paid in prior years, while the Oregon NOL has been carried forward to reduce current and future taxable income. We anticipate that we will be able to use all loss carryforwards in future years. The 2008 Oregon NOL would expire in 2023 if not used in earlier years.

In February 2009, the American Recovery and Reinvestment Act of 2009 (Act) was signed into law. This Act provides a 50 percent bonus depreciation deduction for qualified property acquired or constructed and placed in service in 2009. We estimate that the bonus depreciation deduction will defer the payment of approximately $12.9 million of federal income taxes during 2009 to future periods.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations (see “Contractual Obligations,” above and Note 11).

Investing Activities

Cash requirements for investing activities in 2009 totaled $162.1 million, an increase of $52.3 million from $109.8 million in 2008. Cash requirements for the acquisition and construction of our utility plant were $91.2 million in 2009, down from $96.6 million in 2008. The decrease is primarily due to reduced capital expenditures from lower customer growth in new construction and reduced system expansion costs.

Cash requirements for investments in non-utility property were $43.9 million in 2009, primarily related to investments in Gill Ranch, compared to $7.4 million in 2008. Cash proceeds of $6.8 million from the sale of our investment in a Boeing 737-300 aircraft were used to partially offset our investments in non-utility activities last year. We added $30.5 million to restricted cash balances in 2009, which collateralizes equipment purchase contracts and bank loans for Gill Ranch, as compared to $5.0 million in 2008. Cash provided by other investing activities in 2009 totaled $3.4 million compared to cash used of $8.3 million in 2008. The change in 2009 is primarily due to a net recovery of capital costs in the amount of $1.6 million from Palomar in 2009 compared to $7.5 million of cash contributions to Palomar in 2008, and $2.3 million in proceeds from life insurance collected in 2009 compared to $0.2 million in 2008.

In 2010, utility capital expenditures are estimated to be between $80 and $90 million, and non-utility capital investments are expected to be between $120 million and $145 million for business development projects that are currently in process (see “2010 Outlook,” above).

Over the five-year period 2010 through 2014, utility capital expenditures are estimated at between $400 and $500 million, reflecting continued customer growth, gas storage development at Mist, technology improvements and utility system improvements, including requirements under the Pipeline Safety Improvement Act of 2002. Most of the required funds for utility capital expenditures and Mist expansion 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. We have a shelf registration statement filed with the SEC. Under this shelf registration, we can issue either debt or equity securities. We expect to file a new shelf registration statement during 2010. As of December 31, 2009, the remaining balance of unused financing available and approved by the OPUC under the current shelf registration was $175 million.

Our funding of the total remaining cost for the current development at Gill Ranch project is estimated to be between $105 million and $125 million. As of December 31, 2009, we have invested $54.7 million of equity funds in Gill

Ranch. The remaining project cost is expected to be met from a combination of equity funds and debt, which will be non-recourse to NW Natural. We have not pledged any of our utility assets, nor have we provided any parent guarantees, toward Gill Ranch’s obligations.

In 2010, Palomar will continue to work on the planning and permitting phase of the pipeline project. The total cost for planning and permitting is estimated to be between $40 million and $50 million, of which our ownership interest is 50 percent. As of December 31, 2009, we have invested $14.1 million. The total cost estimate for the entire 217-mile pipeline, if constructed, is estimated to be between $750 million and $800 million, with our current 50 percent share estimated at between $375 million and $400 million. The initial planning and developing costs will be financed with equity funds from us and our partner, TransCanada. See "2010 Outlook," above.

Table of Contents

The Palomar pipeline project includes both an east and west segment. Palomar intends to proceed with the construction of the west segment of the pipeline if an LNG terminal is developed. However, the development of LNG terminals along the Columbia River may or may not proceed, dependent upon a variety of factors, including obtaining state and federal permits, securing acceptable financing and economic conditions. Palomar had executed precedent agreements whereby a significant majority of the pipeline capacity was committed to one shipper. In April 2009, Palomar and that shipper replaced their existing precedent agreement with a new agreement for the same amount of capacity and Palomar received $15.8 million of cash proceeds which had supported the shipper's obligations under the prior agreement. The cash proceeds received were applied against project costs. Under the precedent agreement now in effect, the shipper currently provides an alternate form of credit support, which is expected to support a portion of the ongoing planning and permitting costs as the project develops. In addition, Palomar has the right to request additional credit support from the shipper at future stages of development. A failure to provide acceptable ongoing credit support to meet the shipper's obligations may result in Palomar reassessing its commitment to the development of the west segment.

Based on an ongoing review of the Palomar pipeline project, and continuing interest expressed by the majority shipper, as well as interest expressed by other potential shippers, PGH believes that the Palomar project is still viable, particularly the east segment. Palomar has binding precedent agreements with two shippers, including our own utility, which represents a majority of the current design capacity on the pipeline. Palomar has also been discussing precedent agreements with other potential shippers for the east segment in particular, should some of that capacity be available. We will continue to manage project risks, evaluate project costs and assess the fair value of our investment on a quarterly basis, including a valuation of the available credit support. Additionally, PGH will continue to evaluate market conditions and project status to determine if and when to proceed with construction of all or some portion of the project. See Part I, Item 1A., "Risk Factors," above.

Financing Activities

Cash used by financing activities in 2009 totaled $76.7 million, as compared to cash provided of $75.9 million in 2008. Factors contributing to the $152.6 million net decrease in financing activities primarily includes a $276.6 million aggregate decrease in the changes in short-term debt between 2009 compared to 2008. The change in short-term debt was partially offset by long-term debt issuances totaling $125 million in 2009. We use long-term debt proceeds primarily to finance capital expenditures, refinance maturing short-term debt and redeem long-term debt maturities as well as for general corporate purposes.

In 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of our common stock through a repurchase program. In 2007, the program was modified to authorize the repurchase of up to 2.8 million shares or up to $100 million and was extended through May 2010. The purchases are made in the open market or through privately negotiated transactions. No repurchases were made in 2009 or 2008. Repurchases in 2007 totaled 963,428 shares or $44.2 million, at an average price of $46.03 per share. 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).

In 2009, we produced free cash flow of $35.8 million, compared to negative free cash flow of $115.3 million in 2008 and free cash flow of $27.5 million in 2007. Free cash flow is the amount of cash remaining after the payment of all cash expenses, capital expenditures (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 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. Provided below is a reconciliation from cash provided by operations (GAAP basis) to our non-GAAP free cash flow.

Thousands	2009	2008	2007
Cash provided by operating activities	$240,335	$34,721	$183,640
Cash used in investing activities	(162,141)	(109,825)	(117,479)
Cash dividend payments on common stock	(42,415)	(40,178)	(38,613)
Free cash flow	$35,779	$(115,282)	$27,548

Table of Contents

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 free 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 operations and maintenance expense and capital accounts based on employee payroll distributions, totaled $14.6 million in 2009, an increase of $10.3 million over 2008.

The fair market value of the assets in these two plans increased to $201.3 million at December 31, 2009 from $163.1 million at December 31, 2008. The increase was due to a positive return on plan assets of $28.6 million and a $25.0 million employer contribution, partially offset by benefit payments of $15.4 million.

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 for plan years beginning after December 31, 2009. However, a delayed effective date of 2011 may apply if the pension plan meets the funding targets of 94 percent in 2009 and 96 percent in 2010. Our qualified defined benefit pension plans are currently underfunded by $83.9 million at December 31, 2009. We plan to make contributions during 2010 of approximately $10 million during the first quarter. For more information, see Note 7.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2009, 2008 and 2007, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.86, 3.76 and 3.92, 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—Contingencies," above). At December 31, 2009, a cumulative $106.0 million in environmental costs was recorded as a regulatory asset, consisting of $36.7 million of costs paid to-date, $59.8 million for additional environmental accruals for costs expected to be paid in the future and accrued regulatory interest of $9.5 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs was 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 11.

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 1.

- 58-

Table of Contents

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 storage facilities, 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. Our PGA mechanisms in Oregon and Washington provide for the recovery from customers of actual commodity costs, except that, for Oregon customers, we currently absorb 10 percent of the higher cost of gas sold, or retain 10 percent of the lower cost, in either case as compared to the annual PGA price built into customer rates.

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion, potential market speculation and other factors that affect short-term supply and demand. Commodity-price financial swap and option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed or capped prices. These financial hedge contracts are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. At December 31, 2009 and 2008, notional amounts under these financial hedge contracts totaled $310.9 million and $393.0 million, respectively. If all of the commodity-based financial hedge contracts had been settled on December 31, 2009, a loss of about $15.8 million would have been realized and recorded to a deferred regulatory account (see Note 10). We monitor the liquidity of our financial hedge contracts. Based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our financial hedge contracts settle by or are extendible to October 31, 2012. The $15.8 million unrealized loss is an estimate of future cash flows based on forward market prices that are expected to be paid as follows: $9.7 million in the next 12-month period, and $6.1 million thereafter. The amount realized will change based on market prices at the time contract settlements are fixed.

Interest Rate Risk

We are exposed to interest rate risk 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 with respect to purchases of natural gas from Canadian suppliers. At December 31, 2009 and 2008, notional amounts under foreign currency forward contracts totaled $6.6 million and $5.2 million, respectively. As of December 31, 2009, all foreign currency forward contracts mature within one year. If all of the foreign currency forward contracts had been settled on December 31, 2009, a gain of $0.3 million would have been realized (see Note 10).

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 a material adverse effect on our financial condition or results of operations.

Table of Contents

Credit exposure to financial derivative counterparties. Based on estimated fair value at December 31, 2009, our overall credit exposure relating to commodity hedge contracts reflects an amount owed to our finance derivative counterparties of $15.8 million. 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 current market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require cash collateral, letters of credit or guarantees as circumstances warrant. Our actual derivative credit exposure, which reflects amounts that financial derivative counterparties owe to us, is $0.2 million, and these are under contracts that expire or are expected to settle on or before October 31, 2012.

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	Dec. 31, 2009	Dec. 31, 2008
AAA/Aaa	$ -	$ (16,827)
AA/Aa	(15,792)	(122,287)
A/A	-	(12,006)
BBB/Baa	-	-
Total	$ (15,792)	$ (151,120)

To mitigate the credit risk of financial derivatives we have master netting arrangements with our counterparties that 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.

Table of Contents

Credit exposure to insurance companies for environmental damage claims. We regularly monitor the financial condition of insurance companies who provide 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 nine insurance companies, of which six 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 guaranty that an insurance company will be able to meet its contractual obligations. The three insurance companies who do not have credit ratings of A- or better are expected to have sufficient funds in reserves to cover these claims. Our credit exposure to insurance companies for environmental claims, which reflects amounts we believe are owed to us, could be material. In the event we are unable to recover environmental expenses from these insurance policies, we will seek recovery of unreimbursed amounts through customer rates.

Weather Risk

We are exposed to weather risk primarily from our regulated utility business. A large percentage of our utility margin is volume driven, and current rates are based on an assumption of average weather. 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, 2009, 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.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Table of Contents

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

Table of Contents

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 NW Natural’s internal control over financial reporting as of December 31, 2009. 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 NW Natural maintained effective internal control over financial reporting as of December 31, 2009.

The effectiveness of internal control over financial reporting as of December 31, 2009 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 26, 2010

Table of Contents

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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 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, 2009, 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for fair value measurements in 2008.

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 26, 2010

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

Thousands, except per share amounts (year ended December 31)	2009	2008	2007
Operating revenues:			
Gross operating revenues	$1,012,711	$1,037,855	$1,033,193
Less: Cost of sales	611,168	656,568	639,150
Revenue taxes	24,656	25,072	25,001
Net operating revenues	376,887	356,215	369,042
Operating expenses:			
Operations and maintenance	127,104	113,360	120,488
General taxes	28,253	26,660	25,288
Depreciation and amortization	62,814	72,159	68,343
Total operating expenses	218,171	212,179	214,119
Income from operations	158,716	144,036	154,923
Other income and expense - net	3,714	3,746	1,445
Interest charges - net of amounts capitalized	40,637	37,579	37,811
Income before income taxes	121,793	110,203	118,557
Income tax expense	46,671	40,678	44,060
Net income	$75,122	$69,525	$74,497
Average common shares outstanding:			
Basic	26,511	26,438	26,821
Diluted	26,576	26,594	26,995
Earnings per share of common stock:			
Basic	$2.83	$2.63	$2.78
Diluted	$2.83	$2.61	$2.76
Dividends declared	$1.60	$1.52	$1.44

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2009	2008
Assets:		
Plant and property:		
Utility plant	$2,216,112	$2,142,988
Less accumulated depreciation	682,060	659,123
Utility plant - net	1,534,052	1,483,865
Non-utility property	146,622	74,506
Less accumulated depreciation and amortization	10,540	9,314
Non-utility property - net	136,082	65,192
Total plant and property	1,670,134	1,549,057
Current assets:		
Cash and cash equivalents	8,432	6,916
Restricted cash	35,543	4,118
Accounts receivable	77,438	81,288
Accrued unbilled revenue	71,230	102,688
Allowance for uncollectible accounts	(3,125)	(2,927)
Regulatory assets - current	29,954	147,319
Fair value of non-trading derivatives	6,504	4,592
Inventories:		
Gas	71,672	86,134
Materials and supplies	9,285	9,933
Income taxes receivable	-	20,811
Prepayments and other current assets	21,302	20,098
Total current assets	328,235	480,970
Investments, deferred charges and other assets:		
Regulatory assets - non-current	316,536	288,470
Fair value of non-trading derivatives	843	146
Other investments	67,365	53,231
Restricted cash	-	901
Other	16,139	5,377
Total investments, deferred charges and other assets	400,883	348,125
Total assets	$2,399,252	$2,378,152

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2009	2008
Capitalization and liabilities:		
Capitalization:		
Common stock - no par value; authorized 100 million shares; issued and outstanding 26,533,028 and 26,501,188 at December 31, 2009 and 2008, respectively	$337,361	$336,754
Earnings invested in the business	328,712	296,005
Accumulated other comprehensive income (loss)	(5,968)	(4,386)
Total common stock equity	660,105	628,373
Long-term debt	601,700	512,000
Total capitalization	1,261,805	1,140,373
Current liabilities:		
Short-term debt	102,000	248,000
Long-term debt due within one year	35,000	-
Accounts payable	123,729	94,422
Taxes accrued	21,037	12,455
Interest accrued	5,435	2,785
Regulatory liabilities - current	46,628	20,456
Fair value of non-trading derivatives	19,643	136,735
Other current and accrued liabilities	39,097	36,467
Total current liabilities	392,569	551,320
Deferred credits and other liabilities:		
Deferred income taxes and investment tax credits	300,898	257,831
Regulatory liabilities - non-current	248,622	228,157
Pension and other postretirement benefit liabilities	127,687	138,229
Fair value of non-trading derivatives	3,193	21,646
Other	64,478	40,596
Total deferred credits and other liabilities	744,878	686,459
Commitments and contingencies (see Note 11)	-	-
Total capitalization and liabilities	$2,399,252	$2,378,152

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND
COMPREHENSIVE INCOME

Thousands	Common Stock and Premium	Earnings Invested in the Business	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Comprehensive Income
Balance at Dec. 31, 2006	$ 371,127	$ 230,774	$ (2,356)	$ 599,545	
Net Income	-	74,497	-	74,497	$ 74,497
Change in unrealized loss from price risk management activities	-	-	(41)	(41)	(41)
Change in non-qualified employee benefit plan liability, net of $487 of tax	-	-	(1,232)	(1,232)	(1,232)
Amortization of non-qualified employee benefit plan liability, net of ($81) of tax	-	-	127	127	127
Restricted stock amortizations	285	-	-	285	
Dividends paid on common stock	-	(38,613)	-	(38,613)	
Tax benefits from employee stock option plan	536	-	-	536	
Stock-based compensation	2,094	-	-	2,094	
Issuance of common stock	2,180	-	-	2,180	
Common stock repurchased	(44,627	-	-	(44,627)	
Balance at Dec. 31, 2007	331,595	266,658	(3,502)	594,751	$ 73,351
Net Income	-	69,525	-	69,525	$ 69,525
Change in unrealized loss from price risk management activities	-	-	41	41	41
Change in non-qualified employee benefit plan liability, net of $731 of tax	-	-	(1,145)	(1,145)	(1,145)
Amortization of non-qualified employee benefit plan liability, net of ($140) of tax	-	-	220	220	220

Restricted stock amortizations	275	-	-	275	
Dividends paid on common stock	-	(40,178)	-	(40,178)	
Tax benefits from employee stock option plan	282	-	-	282	
Stock-based compensation	1,523	-	-	1,523	
Issuance of common stock	3,079	-	-	3,079	
Balance at Dec. 31, 2008	336,754	296,005	(4,386)	628,373	$ 68,641
Net Income	-	75,122	-	75,122	$ 75,122
Change in non-qualified employee benefit plan liability, net of $1,273 of tax	-	-	(1,936)	(1,936)	(1,936)
Amortization of non-qualified employee benefit plan liability, net of ($58) of tax	-	-	354	354	354
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	$ 73,540

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

Thousands (year ended December 31)	2009	2008	2007
Operating activities:			
Net income	$75,122	$69,525	$74,497
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	62,814	72,159	68,343
Deferred income taxes and investment tax credits	36,775	50,192	(5,252)
Undistributed gains from equity investments	(1,329)	(667)	(130)
Deferred gas costs - net	36,819	(45,291)	38,665
Gain on sale of non-utility investments	(45)	(1,737)	(1,544)
Income from life insurance investments	(3,416)	(2,190)	(1,939)
Contributions to qualified defined benefit pension plans	(25,000)	-	-
Non-cash expenses related to qualified defined benefit pension plans	9,914	2,855	4,387
Deferred environmental expenditures	(10,069)	(8,179)	(8,842)
Settlement of interest rate hedge	(10,096)	-	-
Deferred regulatory costs and other	(15,029)	(9,347)	(2,940)
Changes in working capital:			
Accounts receivable and accrued unbilled revenue - net	35,506	(36,493)	22,029
Inventories of gas, materials and supplies	15,110	(16,123)	(1,816)
Income taxes receivable	20,811	(20,811)	-
Prepayments and other current assets	(1,204)	363	(6,528)
Accounts payable	1,188	(24,540)	5,841
Accrued interest and taxes	11,232	(724)	(8,190)
Other current and accrued liabilities	1,232	5,729	7,059
Cash provided by operating activities	240,335	34,721	183,640
Investing activities:			
Investment in utility plant	(91,201)	(96,582)	(93,785)
Investment in non-utility property	(43,923)	(7,416)	(24,442)
Proceeds from sale of non-utility investments	120	7,531	2,628
Proceeds from life insurance	2,255	208	881
Net proceeds from (contributions to) non-utility equity investments	1,600	(7,450)	(5,413)
Restricted cash	(30,524)	(5,006)	-
Other	(468)	(1,110)	2,652
Cash used in investing activities	(162,141)	(109,825)	(117,479)
Financing activities:			
Common stock issued (purchased), net of expenses	(375)	2,310	2,180
Common stock repurchased	-	-	(44,627)
Long-term debt issued	125,000	-	-
Long-term debt retired	(300)	(5,000)	(29,500)
Change in short-term debt - net	(158,851)	117,751	43,000
Cash dividend payments on common stock	(42,415)	(40,178)	(38,613)
Other	263	1,030	1,739
Cash provided by (used in) financing activities	(76,678)	75,913	(65,821)
Increase in cash and cash equivalents	1,516	809	340
Cash and cash equivalents - beginning of period	6,916	6,107	5,767
Cash and cash equivalents - end of period	$8,432	$6,916	$6,107

Supplemental disclosure of cash flow information:			
Interest paid	$36,762	$37,669	$38,508
Income taxes paid	$10,000	$12,300	$56,215

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Organization and Principles of Consolidation

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), which primarily consist of our regulated gas distribution business and our regulated gas storage business, which includes our wholly-owned subsidiary Gill Ranch Storage, LLC (Gill Ranch), and other investments and business activities, which primarily consist of our wholly-owned subsidiary NNG Financial Corporation (Financial Corporation) and an equity investment in a natural gas transmission pipeline (See Note 2).

In this report, the term "utility" is used to describe the gas distribution business and the term "non-utility" is used to describe the gas storage business and other non-utility investments and business activities (see Note 2). Intercompany accounts and transactions have been eliminated, except for transactions required to be included under regulatory accounting standards to reflect the effect of such regulation.

Investments in corporate joint ventures and partnerships in which our ownership interest is 50 percent or less and over which we do not exercise control are accounted for by the equity method or the cost method.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts in the consolidated financial statements and accompanying notes. Actual amounts could differ from those estimates and changes would 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 Oregon Public Utility Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC), and gas storage services, which are regulated by the Federal Energy Regulatory Commission (FERC), 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 regulatory accounting. Our businesses with cost-based rates are authorized by the OPUC, WUTC and the FERC to earn a reasonable return on invested capital, while our business with market-based rates is authorized by the CPUC to earn a return to the extent we are able to charge competitive prices above our costs.

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

Table of Contents

At December 31, 2009 and 2008, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		Non-Current	
Thousands	2009	2008	2009	2008
Regulatory assets:				
Unrealized loss on non-trading derivatives(1)	$ 19,643	$ 136,735	$ 3,193	$ 21,646
Income tax asset	-	-	76,240	69,948
Pension and other postretirement benefit obligations(2)	7,502	8,074	109,932	113,869
Environmental costs - paid(3)	-	-	46,204	36,135
Environmental costs - accrued but not yet paid(3)	-	-	59,844	29,969
Other(4)	2,809	2,510	21,123	16,903
Total regulatory assets	$ 29,954	$ 147,319	$ 316,536	$ 288,470
Regulatory liabilities:				
Gas costs payable	$ 37,055	$ 5,284	$ 6,915	$ 1,868
Unrealized gain on non-trading derivatives(1)	6,504	4,592	843	146
Accrued asset removal costs	-	-	238,757	223,716
Other(4)	3,069	10,580	2,107	2,427
Total regulatory liabilities	$ 46,628	$ 20,456	$ 248,622	$ 228,157

(1) An unrealized gain or loss on non-trading derivatives does not earn a rate of return or a carrying charge. These amounts, when realized at settlement, are recoverable through utility rates as part of the purchased gas adjustment mechanism.
(2) Qualified pension plan and other postretirement benefit obligations are approved for regulatory deferral. Such amounts are recoverable in rates, including an interest component, when recognized in net periodic benefit cost (see Note 7).
(3) Regulatory environmental costs are related to sites that are approved for regulatory deferral. We earn the authorized rate of return as a carrying charge on amounts paid, whereas the amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended.
(4) 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.

The amortization period for our regulatory assets and liabilities ranges from less than one year to an undeterminable period. Our regulatory liabilities 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 obligations and accrued asset removal costs, are large and tend to be amortized over longer periods once we have agreed upon an amortization period with the respective regulatory agency.

We believe that continued application of regulatory accounting for regulated activities is appropriate and consistent with the current regulatory environment, and that all regulated assets and liabilities at December 31, 2009 and 2008 will be recoverable or refundable through future utility rates. We annually review all regulatory assets for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets 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.

Table of Contents

New Accounting Standards

Adopted Standards

Business Combinations. Effective January 1, 2009, we adopted authoritative guidance on business combinations. This guidance amends the principles and requirements for how an acquiror accounts for and discloses its business combinations. The adoption of this standard did not have a material effect on our financial condition, results of operations or cash flows.

Noncontrolling Interests. Effective January 1, 2009, we adopted authoritative guidance on consolidation. This guidance amends the reporting requirements of consolidation for noncontrolling interests in subsidiaries to improve the relevance, comparability and transparency of the financial information disclosed. The adoption of this standard did not have a material effect on our financial condition, results of operations or cash flows.

Derivative Instruments and Hedging Activities. Effective January 1, 2009, we adopted authoritative guidance on derivatives and hedging, which requires enhanced disclosures on derivative instruments and hedging activities. This guidance expands disclosures by adding qualitative disclosures about our hedging objectives and strategies, fair value gains and losses, and credit-risk-related contingent features in derivative agreements. The disclosures are intended to provide an enhanced understanding of:

- how and why we use derivative instruments;
- how derivative instruments and related hedge items are accounted for; and
- how derivative instruments and related hedged items affect our financial condition, results of operations and cash flows.

The adoption and implementation of this standard did not have, and is not expected to have, a material effect on our financial statement disclosures. The required disclosures are included in Note 10, below.

Determining Whether Share-Based Payment Transactions are Participating Securities. Effective January 1, 2009, we adopted authoritative guidance on earnings per share. This guidance requires nonforfeitable rights to dividends or dividend equivalents on unvested share-awards to be included in the computation of earnings per share under the two-class method. The adoption of this standard did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flows.

Fair Value Considerations. Effective for periods ending after June 15, 2009, we adopted authoritative guidance on fair value measures and disclosures. This pronouncement provides guidance and required disclosures, if necessary, to determine if the market for measuring our financial instruments has significantly decreased in volume and level of activity. The adoption of this standard did not have a material effect on our financial statement disclosures.

Subsequent Events. Effective for periods ending after June 15, 2009, we adopted authoritative guidance on subsequent events. This guidance establishes principles and disclosure requirements for events or transactions that occur after the balance sheet date but before the financial statements are issued. As of February 26, 2010, we have evaluated events subsequent to the balance sheet date. For subsequent events, see Note 12.

Plan Assets in Postretirement Benefit Plans. Effective for annual periods ending after December 15, 2009, we adopted authoritative guidance on pension and other postretirement benefits, which requires enhanced disclosures of plan assets in an employer's defined benefit pension or other postretirement benefit plans. The disclosures are intended to provide an enhanced understanding of:

- how investment allocation decisions are made;
- the major categories of plan assets;
- the inputs and valuation techniques used to measure the fair value of plan assets;
- the effect of fair value measurements using significant unobservable inputs (Level 3 input from accounting for fair value measures and disclosures) on changes in plan assets for the period; and
- significant concentration or risk within plan assets.

Table of Contents

The adoption of this pronouncement did not have a material effect on our financial statement disclosures.

Fair Value Disclosures. Effective for periods ending after December 15, 2009, we adopted authoritative guidance on fair value measures and disclosures. This guidance requires additional disclosures for significant transfers between levels in the fair value hierarchy, enhanced disclosures for the level 3 rollforward table and more disaggregation of fair value inputs. The adoption of this pronouncement did not have a material impact on our financial statement disclosures.

Recent Accounting Pronouncements

Variable Interest Entity. In 2009, the Financial Accounting Standards Board (FASB) issued authoritative guidance on variable interest entities. This guidance requires an analysis to determine whether our variable interest provides us with a controlling financial interest in the variable interest entity. It defines the primary beneficiary of the variable interest entity as the entity having:

- power to control the activities that most significantly impact the performance; and
- the obligation to absorb losses or right to receive benefits from the entity that could potentially be significant to the variable interest entity.

These changes are effective for the interim and annual reporting periods that begin after November 15, 2009. We are evaluating the impact these updates will have on our investments in variable interest entities. If consolidated, our variable interest entities could have a material impact on our balance sheet, but it is not expected to materially impact our results of operations or cash flows.

Plant and Property and Accrued Asset Removal Costs

Plant and property is stated at cost, including capitalized labor, materials and overhead (see Note 9). In accordance with regulatory accounting, the cost of constructing utility plant and gas storage assets generally includes an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the net financing cost during the period the funds are used for construction purposes (see "Allowance for Funds Used During Construction," below). When gas storage assets under construction are expected to be subject to market based rates, then the cost of construction will include capitalized interest in accordance with GAAP, not regulatory AFUDC.

Our provision for depreciation of utility property is computed under the straight-line, age-life method in accordance with external engineering studies and as approved by regulatory authorities. The weighted average depreciation rate for plant in service was approximately 2.9 percent for the year ended December 31, 2009 and approximately 3.4 percent for the years ended 2008 and 2007, reflecting the approximate average economic life of the property.

In accordance with long-standing industry practice, we accrue for future asset removal costs on many long-lived assets through a charge to depreciation expense allowed in rates and accumulate such amounts in regulatory liabilities. At the time removal costs are incurred, accumulated depreciation is charged with the costs of removal and the book cost of the asset. Our estimate of accumulated removal costs is based on rates using approved depreciation studies. No gain or loss is recognized upon normal retirement. In the rate setting process, the accrued asset removal costs are treated as a reduction to net rate base.

Table of Contents

Allowance for Funds Used During Construction

Certain additions to utility plant include AFUDC, which represents the net cost of borrowed or other funds used during construction and is calculated using actual current interest rates and authorized rates for return on equity, if applicable. If borrowings are less than the total costs of construction work in progress, then a composite rate of interest on all debt, shown as a reduction to interest charges, and a return on equity funds, shown as other income, is used to compute the AFUDC. While cash is not realized currently from AFUDC, it is realized in future years through increased revenues from rate recovery resulting from higher rate base and higher depreciation expense. Our composite AFUDC rates were 1.0 percent in 2009, 3.6 percent in 2008 and 5.4 percent in 2007.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand and highly liquid temporary investments with original maturity dates of three months or less. At December 31, 2008, outstanding checks of approximately $1.0 million were included within accounts payable, but no such reclasses were required in 2009.

Revenue Recognition and Accrued Unbilled Revenues

Utility revenues, derived primarily from the sale and transportation of gas, are recognized when the gas is delivered to and received by the customer. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of gas 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. Accrued unbilled revenues are reversed the following month when actual billings occur. Our accrued unbilled revenues at December 31, 2009 and 2008 were $71.2 million and $102.7 million, respectively.

Utility operating revenues also include the recognition of a regulatory adjustment for income taxes paid. This revenue adjustment reflects an OPUC rule whereby we are required to implement a rate refund or a rate surcharge to utility customers. This automatic refund or surcharge is accrued based on the estimated difference between income taxes paid and income taxes authorized to be collected in rates for each tax year.

Non-utility revenues, derived primarily from gas storage business segment, are recognized upon delivery of services to customers. Revenues from our asset optimization partner are recognized over the life of the optimization contract for the guaranteed amount, and recognized as earned for amounts above the guaranteed amount. See Note 2.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consist primarily of amounts due for gas sales and transportation services to core utility customers, plus amounts due for gas storage services and other miscellaneous receivables. 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 current past due accounts 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 changes in general economic conditions, customer credit issues and the level of natural gas prices. Each quarter the allowance for uncollectible accounts is adjusted, as necessary, based on the most current information available.

Table of Contents

Inventories

Inventories, which consist primarily 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 gas inventories provides for cost recovery in customer rates. All gas that is injected into storage is priced into inventory based on actual purchase costs. All gas that is withdrawn from inventory is charged to cost of gas during the current period at the weighted average cost of inventory. Material and supplies inventories are stated at the lower of average cost or net realizable value.

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 and hedges requires that changes in the fair value of a derivative 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 derivatives contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these contracts are deferred as regulatory assets or liabilities pursuant to regulatory accounting. Derivatives contracts entered into for core utility customer requirements after the purchased gas adjustment (PGA) rate has been set are subject to the PGA incentive sharing mechanism. Under our PGA sharing mechanism in effect prior to November 1, 2008, 67 percent of the changes in fair value were deferred as regulatory assets or liabilities and the remaining 33 percent was recorded to the income statement for derivatives that do not qualify for hedge accounting, and to Other Comprehensive Income for hedges that do qualify for hedge accounting. A modified PGA sharing mechanism was approved in Oregon, effective on November 1, 2008, under which we are required to select, by August 1 of each year, 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, respectively. For the PGA year in Oregon beginning November 1, 2009, we selected the 90 percent deferral of gas cost differences. For the PGA year in Oregon beginning November 1, 2008, we selected the 80 percent deferral of gas cost differences. In Washington, 100 percent of our gas costs are deferred. See Note 10.

Our financial derivatives policies set forth the guidelines for using selected financial derivative products to support prudent risk management strategies within designated parameters. Our objective for using derivatives is to decrease the volatility of 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 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.

Table of Contents

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; and (g) credit spreads, as well as other relevant economic measures.

Revenue Taxes

We account for revenue-based taxes assessed by governmental entities as a separate cost collected from customers for remittance to those governmental entities. 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 investment 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 8).

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 $76.2 million and $69.9 million at December 31, 2009 and 2008, 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, 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 and leveraged leases, which reduce income taxes payable, are deferred for financial statement purposes and amortized over the life of the related plant or lease.

Other Income and Expense – Net

Other income and expense – net consists of income from company-owned life insurance, interest on deferred regulatory account balances and short-term debt cash investments, income from equity investments, gain on sale of investments, non-operating expenses related to our proposed pipeline project and other miscellaneous income and expense from merchandise sales, rents, leases and other items.

Thousands	2009	2008	2007
Gains from company-owned life insurance	$ 3,416	$ 2,190	$ 1,939

Interest income	211	250	537
Income from equity investments	1,329	667	130
Net interest on deferred regulatory accounts	2,051	552	84
Gain on sale of investments	45	1,737	1,544
Other non-operating	(3,338)	(1,650)	(2,789)
Total other income and expense - net	$ 3,714	$ 3,746	$ 1,445

Table of Contents

Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding each year. Diluted earnings per share reflect the potential effects of the exercise of stock options and other stock-based compensation. Diluted earnings per share are calculated as follows:

Thousands, except per share amounts	2009	2008	2007
Net income	$ 75,122	$ 69,525	$ 74,497
Average common shares outstanding - basic	26,511	26,438	26,821
Effect on shares from stock options and other stock based compensation	65	156	174
Average common shares outstanding - diluted	26,576	26,594	26,995
Earnings per share of common stock - basic	$ 2.83	$ 2.63	$ 2.78
Earnings per share of common stock - diluted	$ 2.83	$ 2.61	$ 2.76

For the years ended December 31, 2009, 2008 and 2007, 2,142 shares, 1,248 shares and 442 shares, respectively, represent the number of stock options which were excluded from the calculation of diluted earnings per share because the effect was antidilutive.

2. CONSOLIDATED SUBSIDIARY OPERATIONS AND 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 also 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 Gill Ranch, LLC (Gill Ranch), and our “other” segment includes our equity investment in a natural gas transmission pipeline and Financial Corporation.

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale and delivery of natural gas, including 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, also 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, while industrial customers account for 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, gas cost savings and other regulatory charges.

Table of Contents

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.

Gas Storage

Our gas storage business segment includes natural gas storage services provided to interstate and intrastate customers in the Pacific Northwest using underground gas storage and pipeline facilities we own and operate. We also use an independent energy marketing company to provide asset optimization services for the utility under a contractual arrangement, the results of which are included in this business segment. For each of the years ended December 31, 2009, 2008 and 2007, this business segment derived a majority of its revenues from our share of asset optimization services performed by an independent energy marketing company and from multi-year gas storage contracts we have with less than 10 customers who contract for service at our Mist storage facility. Five storage customers currently account for over 90 percent of our existing contract storage capacity, with the largest customer accounting for about half of that total capacity. These five customers have contracts that expire at various dates through April 2017.

Results for the gas storage segment include revenues, net of amounts shared with core utility customers, from a contract with an independent energy marketing company that optimizes the use of our utility assets when not needed to serve core utility customers. In Oregon, we retain 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 optimization.

In 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility at Gill Ranch near Fresno, California. We formed a wholly-owned subsidiary of NW Natural, Gill Ranch, to develop and operate the facility. Gill Ranch owns 75 percent of the project, and PG&E owns 25 percent. As of December 31, 2009 and 2008, total assets at Gill Ranch were $116.3 million and $13.2 million, respectively.

While our primary focus for growing the gas storage business is on the current development at Gill Ranch, we also plan to continue expanding our interstate storage facilities at Mist, Oregon. In 2009, we completed three-dimensional seismic surveys and initiated engineering work for a new 3 to 4 Bcf expansion at Mist. Pending successful marketing efforts, we expect to move forward with the project and would target a 2011 in-service date. The total project cost estimates are between $45 million and $55 million. This estimated cost range includes the development of a second compression station and a pipeline gathering system at Mist that will enable future storage expansions. The total Mist gas storage assets, excluding amounts allocated to our utility, was $58.4 million in 2009 and $56.5 million in 2008.

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 based on our current 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 Financial Corporation. This segment also includes some operating and non-operating revenues and expenses of the parent company that cannot be allocated to utility operations. As of December 31, 2009 and 2008, our investment balance in Palomar, which is net after tax of amounts received in 2009 from a shipper credit support agreement, was $14.1 million and $14.2 million, respectively. The total cost estimate for the entire 217-mile pipeline, if constructed, is estimated to be between $700 million and $800 million, with our current 50 percent share estimated at between $350 million and $400 million. Palomar has executed binding precedent agreements with shippers, including our own utility, for a majority of the current design capacity on the pipeline. These agreements also provide commitments of credit support to the project. Our maximum loss exposure related to Palomar at December 31, 2009 would be limited to our investment balance less any commitments or credit support recovered from third parties.

Table of Contents

In 2008, we sold our investment in a Boeing 737-300 aircraft for approximately $6.8 million total including accrued rents. We purchased the aircraft in 1987 and leased it to Continental Airlines for the entire time it was owned by NW Natural. As a result of the sale, we recognized an after-tax gain of $1.1 million in 2008. In 2007, we sold our limited partnership interest in two wind power electric generation projects in California for $2.1 million, which resulted in an after-tax gain of $0.9 million.

Financial Corporation 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. Financial Corporation's total assets were $1.4 million and $1.3 million at December 31, 2009 and 2008, respectively.

Segment Information Summary

The following table presents summary financial information about the reportable segments for the years ended 2009, 2008 and 2007. Inter-segment transactions are insignificant.

Thousands	Utility	Gas Storage	Other	Total
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
Total assets at Dec. 31, 2009	2,205,313	173,648	20,291	2,399,252
2008				
Net operating revenues	$ 337,596	$ 18,459	$ 160	$ 356,215
Depreciation and amortization	70,690	1,469	-	72,159
Income from operations	128,957	14,943	136	144,036
Net income	58,739	8,363	2,423	69,525
Total assets at Dec. 31, 2008	2,289,601	72,073	16,478	2,378,152
2007				
Net operating revenues	$ 351,875	$ 16,999	$ 168	$ 369,042
Depreciation and amortization	67,410	933	-	68,343
Income from operations	140,434	14,481	8	154,923
Net income	64,938	8,454	1,105	74,497

Table of Contents

3. CAPITAL STOCK:

Common Stock

As of December 31, 2009 and 2008, we had 100 million common shares authorized.

As of December 31, 2009, we had reserved for issuances 194,918 shares of common stock under the Employee Stock Purchase Plan (ESPP), 480,959 shares under our Dividend Reinvestment and Direct Stock Purchase Plan and 1,295,585 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 2010 to repurchase up to an aggregate of 2.8 million shares, or up to $100.0 million. No shares of common stock were repurchased pursuant to this program in 2009 or 2008. Since inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding for the years 2009, 2008 and 2007:

	Shares
Balance, Dec. 31, 2006	27,283,741
Sales to employees	21,373
Exercise of stock options - net	75,850
Repurchase	(973,616)
Balance, Dec. 31, 2007	26,407,348
Sales to employees	19,500
Exercise of stock options - net	74,340
Balance, Dec. 31, 2008	26,501,188
Sales to employees	8,615
Exercise of stock options - net	23,225
Balance, Dec. 31, 2009	26,533,028

4. STOCK-BASED COMPENSATION:

We have several stock-based compensation plans, including: a the Long-Term Incentive Plan (LTIP); a Restated SOP; an ESPP; and a Non-Employee Directors Stock Compensation Plan (NEDSCP). These plans are designed to promote stock ownership in NW Natural by employees and officers and, in the case of the NEDSCP, by non-employee directors.

Long-Term Incentive Plan. The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. An aggregate of 500,000 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.

At December 31, 2009, 230,858 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 recognized based on the fair value of performance-based stock awards, or a pro rata amortization over the vesting period for the outstanding awards of restricted stock.

Table of Contents

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, 2009, certain performance-based stock award measures had been achieved for the 2007-09 award period. Accordingly, participants are estimated to receive 16,784 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, 2008 and 2007, we awarded 58,244 and 66,666 shares of common stock, respectively, for the 2006-08 and 2005-07 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. During 2009, we expensed $0.5 million related to the 2007-09 performance-based stock award, and on a cumulative basis we accrued a total $1.5 million related to the 2007-09 performance period. In 2008 and 2007, we expensed $0.5 million and $0.6 million, respectively, related to the 2006-08 and 2005-07 performance-based stock award periods, and on a cumulative basis we accrued a total of $2.0 million for both 2006-08 and 2005-07 performance periods.

At December 31, 2009, the aggregate number of performance-based shares granted and outstanding at the threshold, target and maximum levels were as follows:

Year	Performance	Performance Share Awards Outstanding		
Awarded	Period	Threshold	Target	Maximum
2008	2008-10	6,935	36,500	73,000
2009	2009-11	7,410	39,000	78,000
	Total	14,345	75,500	151,000

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 accounting for stock compensation, based on performance levels achieved and an estimated fair value using a Black-Scholes or binomial model. The weighted-average per share grant date fair value of unvested shares at December 31, 2009 and 2008 was $19.40 and $20.95, respectively. The weighted-average per share grant date fair value of shares vested during the year was $27.85 and granted during the year was $18.74. In 2009 and 2008, under these LTIP grants we accrued $1.0 million and expensed $0.9 million, while in 2007 we accrued $2.7 million and expensed $2.3 million.

Restricted Stock Awards. Restricted stock awards also have been granted under the LTIP.   A restricted stock award was granted in 2004 consisting of 5,000 shares that vested ratably over the period 2005-09, and a restricted stock award was granted in 2006 consisting of 6,500 shares that vested ratably over the period 2007-09. As of December 31, 2009, all restricted stock awards were fully vested and paid out.

Restated Stock Option Plan. A total of 2,400,000 shares of common stock were reserved for issuance under the Restated SOP. 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.

Table of Contents

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:

	February 2009	September 2008	February 2008	February 2007
Risk-free interest rate	2.0 %	3.0 %	2.8 %	4.7 %
Expected life (in years)	4.7	4.7	4.7	6.2
Expected market price volatility factor	22.5 %	18.4 %	18.4 %	17.2 %
Expected dividend yield	3.8 %	2.9 %	3.5 %	3.2 %
Forfeiture rate	3.7 %	3.9 %	3.8 %	4.4 %
Weighted average grant date fair value	$ 5.46	$ 7.05	$ 5.34	$ 7.66

The expected life of the 2009 and 2008 grants was calculated based on our actual experience with previously exercised option grants. The simplified formula for "plain vanilla" options was used in 2007 to determine the expected life as defined and permitted by stock option accounting guidance. The risk-free interest rate was based on the implied yield currently available on U.S. Treasury zero-coupon issues with a life equal to the expected life of the options. Historical data was used to estimate the volatility factor, measured on a daily basis, for a period equal to the duration of the expected life of the option awards. The dividend yield was based on management's current estimate for future dividend payouts at the time of grant. We expense the total cost of stock option awards granted to retirement eligible employees at the date of grant in accordance with stock option accounting guidance and the retirement vesting provisions of our option agreements.

Information regarding the Restated SOP activity for the three years ended December 31, 2009 is summarized as follows:

	Option Shares	Price per Share Range	Weighted - Average Exercise Price	Intrinsic Value (In millions)
Balance outstanding, Dec. 31, 2006	334,000	$ 20.25 - 38.30	$ 31.14	n/a
Granted	100,600	44.48	44.48	n/a
Exercised	(75,850)	20.25 - 34.95	28.73	1.4
Forfeited	(1,000)	44.48	44.48	n/a
Balance outstanding, Dec. 31, 2007	357,750	20.25 - 44.48	35.36	4.8
Granted	119,050	43.29 - 51.09	43.62	n/a
Exercised	(74,340)	20.25 - 44.48	30.70	1.3
Forfeited	(6,050)	26.30 - 44.48	41.56	n/a
Balance outstanding, Dec. 31, 2008	396,410	20.25 - 51.09	38.62	2.3
Granted	111,750	41.15	41.15	n/a
Exercised	(23,225)	20.25 - 34.95	30.92	0.3

Forfeited	-		n/a		n/a		n/a
Balance outstanding, Dec. 31, 2009	484,935	$	26.30 - 51.09	$	39.57	$	2.7
Shares available for grant							
Dec. 31, 2007							1,035,400
Dec. 31, 2008							922,400
Dec. 31, 2009							810,650

Table of Contents

In the year ended December 31, 2009, cash of $1.1 million was received for option shares exercised and a $0.2 million related tax benefit was realized. For the 12 months ended December 31, 2009, 2008 and 2007, the total fair value of options that vested was $0.4 million, $0.3 million and $0.2 million, respectively.

The following table summarizes additional information about stock options outstanding and exercisable at December 31, 2009:

	Outstanding		Exercisable			
Range of Exercise Prices	Stock Options	Weighted-Average Remaining Life in Years	Stock Options	(In millions) Aggregate Intrinsic Value	Weighted-Average Exercise Price	Weighted-Average Remaining Life in Years
$26.30 - 51.09	484,935	7.19	254,948	$2.0	$37.39	6.10

As of December 31, 2009, there was $0.7 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2012.

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 $24,000 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	2009	2008	2007
Operations and maintenance expense, for stock-based compensation	$ 1,434	$ 1,598	$ 2,986
Income tax benefit	(559)	(623)	(1,165)
Net stock-based compensation effect on net income	$ 875	$ 975	$ 1,821
Amounts capitalized for stock-based compensation	$ 229	$ 282	$ 479

Non-Employee Directors Stock Compensation Plan. In February 2004, the NEDSCP was amended to permit non-employee directors to receive stock awards either in cash or in stock. As a result of modifications to the directors' compensation arrangements, the NEDSCP was further amended in September 2004 to eliminate any further awards, either in cash or stock, on and after January 1, 2005.

Prior to the September 2004 amendment to the NEDSCP, if non-employee directors elected to receive their awards in stock, approximately $100,000 worth of common stock was awarded upon joining the Board. These stock awards were subject to vesting and to restrictions on sale and transferability. The shares vested in monthly installments over the five calendar years following the award. On January 1 of each year following the initial award, non-employee directors who elected to receive their awards in stock were awarded an additional $20,000 worth of restricted stock, which vested in monthly installments in the fifth year following the award (after the previous award had fully vested). We hold the certificates for the restricted shares until the non-employee director ceases to be a director. Participants receive all dividends and have full voting rights on both vested and unvested shares. All awards vest immediately upon the death of a director or upon a change in control of the Company. Any unvested shares are considered to be unearned compensation, and thus are forfeited if the recipient ceases to be a director. The shares were purchased in the open market at the time of the award. At December 31, 2009, all shares were fully vested.

Table of Contents

5. COST AND FAIR VALUE BASIS 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.

The maturities on the long-term debt outstanding for each of the 12-month periods through December 31, 2014 amount to: $35 million in 2010; $10 million in 2011; $40 million in 2012; none in 2013; and $60 million in 2014.

Thousands	2009	2008	2007
Medium-Term Notes			
First Mortgage Bonds:			
6.50% Series B due 2008	$ -	$ -	$ 5,000
4.11% Series B due 2010	10,000	10,000	10,000
7.45% Series B due 2010	25,000	25,000	25,000
6.665% Series B due 2011	10,000	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(1)	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(2)	75,000	-	-
9.05% Series A due 2021	10,000	10,000	10,000
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(3)	19,700	20,000	20,000
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
	636,700	512,000	517,000
Less long-term debt due within one year	35,000	-	5,000
Total long-term debt	$ 601,700	$ 512,000	$ 512,000

(1) Issued in July 2009

(2) Issued in March 2009

(3) In November 2009 one investor in our 6.65 percent secured MTNs due 2027 exercised its right under a one-time put option to redeem $0.3 million of the $20 million outstanding. This one-time put option has now expired, and the remaining $19.7 million remaining principal outstanding is expected to be redeemed at maturity in November 2027.

In March 2009, we issued $75 million of 5.37 percent secured MTNs due February 1, 2020, and in July 2009, we issued another $50 million of secured MTNs with an interest rate of 3.95 percent and a maturity of July 15, 2014. Proceeds from these MTNs were used to fund utility capital expenditures, to redeem utility short-term debt, and to provide utility working capital for general corporate purposes.

According to fair value accounting, we elected to not adjust our long-term debt balance to fair value. The following table provides an estimate of the fair value of our long-term debt, using market prices in effect on the valuation date. Interest rates for debt with similar credit ratings, terms and remaining maturities were used to estimate fair value for long-term debt issues.

	Dec. 31, 2009		Dec. 31, 2008	
Thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt including amounts due within one year	$ 636,700	$ 707,755	$ 512,000	$ 505,828

6. 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 to meet seasonal working capital requirements, including the financing of gas purchases, gas inventories and accounts receivable, 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. Our current bank loans at Gill Ranch are supported by cash collateral. At December 31, 2009 and 2008, the amounts and average interest rates of commercial paper debt outstanding were $69.8 million at 0.3 percent and $248.0 million at 1.6 percent, respectively, while bank loans outstanding were $32.2 million at 0.8 percent and $0, respectively.

In March 2009, Gill Ranch entered into a cash collateralized credit facility for up to $40 million that has been extended until September 30, 2010. As of December 31, 2009, Gill Ranch had $32.2 million of borrowings outstanding included under short-term debt on the balance sheet, with a corresponding cash collateral amount included under restricted cash – current on the balance sheet. The effective interest rate on Gill Ranch's credit facility is 0.8 percent.

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 credit agreement to May 31, 2013. The credit 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 credit agreement. The credit 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 credit agreement are due and payable on or before the expiration date, which is May 31, 2013. Additionally, we had two committed bilateral bank lines of credit totaling $30 million in effect as of November 2008, of which $15 million expired December 31, 2008 and $15 million expired February 27, 2009. There were no outstanding balances under the syndicated credit and no letters of credit issued or outstanding at December 31, 2009 and 2008.

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.

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, 2009 and 2008, with a consolidated indebtedness to total capitalization ratio of 52.8 percent, and 54.7 percent, respectively.

Table of Contents

7. PENSION AND OTHER POSTRETIREMENT BENEFITS:

We maintain two qualified non-contributory defined benefit pension plans, several non-qualified supplemental pension plans for eligible executive officers and certain key employees, and other postretirement employee benefit plans. Only the two qualified defined benefit pension plans 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 for non-union and union employees, respectively, were closed to new participants. Instead, non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, are currently provided an enhanced Retirement K Savings Plan (RKSP) 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 over the three-year period ended December 31, 2009, and a summary of the funded status and amounts recognized in the consolidated balance sheets using measurement dates of December 31, 2009, 2008 and 2007:

	Postretirement Benefits					
	Pension Benefits			Other Benefits		
Thousands	2009	2008	2007	2009	2008	2007
Reconciliation of change in benefit obligation:						
Obligation at January 1	$ 281,127	$ 260,561	$ 269,410	$ 23,863	$ 22,186	$ 22,436
Service cost	6,402	6,141	8,708	522	521	505
Interest cost	17,948	17,373	16,057	1,568	1,403	1,293
Benefits paid	(17,149)	(16,247)	(15,924)	(1,428)	(1,259)	(1,299)
Plan amendments	(3,921)	5	3,887	-	-	-
Change in assumptions	14,265	9,146	(23,916)	1,099	839	(645)
Net actuarial (gain) or loss	9,319	4,291	2,339	(883)	173	(104)
Liability transfer	-	(143)	-	-	-	-
Obligation at December 31	$ 307,991	$ 281,127	$ 260,561	$ 24,741	$ 23,863	$ 22,186
Reconciliation of change in plan assets:						
Fair value of plan assets at January 1	$ 163,115	$ 241,418	$ 236,518	$ -	$ -	$ -
Actual return on plan assets	28,641	(63,267)	19,658	-	-	-
Employer contributions	26,705	1,211	1,166	1,428	1,259	1,298
Benefits paid	(17,149)	(16,247)	(15,924)	(1,428)	(1,259)	(1,298)
Fair value of plan assets at December 31	$ 201,312	$ 163,115	$ 241,418	$ -	$ -	$ -
	$ (106,679)	$ (118,012)	$ (19,143)	$ (24,741)	$ (23,863)	$ (22,186)

Funded status at December 31

Our qualified defined benefit pension plans had an aggregate projected benefit obligation of $285.2 million, $261.5 million and $243.1 million at December 31, 2009, 2008 and 2007, respectively, and the fair value of plan assets was $201.3 million, $163.1 million and $241.4 million, respectively. Changes in valuation assumptions impact our projected benefit obligations. Benefit obligations at December 31, 2009 increased $19.1 million due to a decrease in our discount rate assumptions and increased by $4.2 million due to changes in other assumptions. The projected benefit obligations at December 31, 2008 increased $7.4 million due to a decrease in the discount rate assumptions and increased by $5.0 million due to updating our mortality table. The combination of investment returns and future cash contributions by the company is expected to provide sufficient funds to cover all future benefit obligations of the plans.

Table of Contents

The following table provides amounts amortized from accumulated other comprehensive income (AOCI) or regulatory assets to net periodic benefit cost during 2009, 2008, and 2007:

	Regulatory Asset Amortization						AOCI Amortization		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
Thousands	2009	2008	2007	2009	2008	2007	2009	2008	2007
Net periodic benefit costs:									
Actuarial loss	$ 6,189	$ -	$ 1,910	$ 17	$ -	$ 4	$ 449	$ 398	$ 245
Prior service cost	1,260	1,290	1,017	197	197	197	(37)	(37)	(36)
Transition obligation	-	-	-	411	411	411	-	-	-
Total	$ 7,449	$ 1,290	$ 2,927	$ 625	$ 608	$ 612	$ 412	$ 361	$ 209

In 2010, an estimated $7.5 million, consisting of $6.4 million of actuarial losses, $0.7 million of prior service cost and $0.4 million transition obligation will be amortized from regulatory assets to net periodic benefit costs and $0.6 million consisting of $0.6 million of actuarial losses and negligible prior service cost will be amortized from AOCI.

An assumed discount rate was determined independently for each pension plan and other postretirement benefit plans 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 to reflect the timing and amount of expected future benefit payments for these plans.

The 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 are 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. Re-balancing will take 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 and active portfolio management by professional investment managers. The Retirement Trust Fund is not currently invested in any NW Natural securities.

Table of Contents

Our pension plan asset allocation at December 31, 2009 and 2008, and the target allocation and expected long-term rate of return by asset category, are as follows:

Asset Category	Percentage of Plan Assets Dec. 31, 2009		Percentage of Plan Assets Dec. 31, 2008		Target Allocation		Expected Long-term Rate of Return	
US Large Cap Equity	17.5	%	14.3	%	18	%	8.25	%
US Small/Mid Cap Equity	13.8	%	9.6	%	12	%	9.25	%
Non-US Equity	19.4	%	17.9	%	18	%	8.85	%
Emerging Markets	0.5	%	0.0	%	5	%	10.50	%
Fixed Income	18.2	%	21.2	%	17	%	5.25	%
Real Estate	6.5	%	11.3	%	8	%	7.00	%
Absolute Return Strategy	15.0	%	18.9	%	15	%	8.00	%
Real Return Strategy	6.8	%	6.8	%	7	%	7.00	%
Cash and cash equivalents	2.3	%	0.0	%	0	%	-	
Weighted Average							8.25	%

Our non-qualified supplemental defined benefit pension plans' benefit obligations were $22.8 million, $19.6 million and $17.5 million at December 31, 2009, 2008 and 2007, 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 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. The accumulated postretirement benefit obligation for those plans was $24.7 million, $23.9 million and $22.2 million at December 31, 2009, 2008 and 2007, respectively.

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.

Table of Contents

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, 2009, 2008 and 2007 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
Thousands	2009	2008	2007	2009	2008	2007
Service cost	$ 6,402	$ 6,141	$ 8,708	$ 522	$ 521	$ 505
Interest cost	17,948	17,373	16,057	1,568	1,403	1,293
Expected return on plan assets	(15,696)	(19,087)	(18,490)	-	-	-
Amortization of transition obligations	-	19	-	411	411	411
Amortization of prior service costs	1,223	1,253	1,188	197	197	197
Amortization of net actuarial loss	6,810	385	2,123	-	-	25
Net periodic benefit cost	$ 16,687	$ 6,084	$ 9,586	$ 2,698	$ 2,532	$ 2,431
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	6.60 %	6.79 %	6.03 %	7.12 %	6.56 %	5.91 %
Rate of increase in compensation	3.25%-5.0%	3.5%-5.0 %	4.0%-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	6.01 %	6.60 %	6.79 %	5.78 %	7.12 %	6.56 %
Rate of increase in compensation	3.25%-5.0%	3.5%-5.0 %	4.0%-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

The assumed annual increase in trend rates used in measuring other postretirement benefits as of December 31, 2009 were 9 percent for medical and 11 percent for prescription drugs. Medical costs were assumed to decrease gradually each year to a rate of 5.0 percent by 2017, while prescription drug costs were 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 total of service and interest cost components of net periodic postretirement health care benefit cost	$ 79	$ (68)
Effect on health care cost component of the accumulated postretirement benefit obligation	$ 713	$ (625)

Table of Contents

The following table provides information regarding employer contributions and benefit payments for the two qualified pension plans, the non-qualified pension plans and the other postretirement benefit plans for the years ended December 31, 2009 and 2008, and estimated future payments:

Thousands				
Employer Contributions by Plan Year		Pension Benefits		Other Benefits
2008	$	1,645	$	1,259
2009		27,137		1,428
2010 (estimated)		6,154		1,921
Benefit Payments				
2007	$	15,924	$	1,298
2008		16,247		1,259
2009		17,149		1,428
Estimated Future Payments				
2010	$	21,120	$	1,921
2011		17,974		1,969
2012		18,639		1,906
2013		19,065		1,920
2014		19,631		1,990
2015-2019		112,487		9,773

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 for plan years beginning after December 31, 2008. However, a delayed effective date of 2011 may apply if the pension plan meets the funding targets of 94 percent in 2009 and 96 percent in 2010. Our qualified defined benefit pension plans are currently underfunded by $83.9 million at December 31, 2009, and we expect to make contributions during 2010 of approximately $10 million.

Our RKSP is a qualified defined contribution plan under Internal Revenue Code Section 401(k). We also have non-qualified deferred compensation plans for eligible officers and senior managers. These plans are designed to enhance the retirement program of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly. Our matching contributions to these plans totaled $2.1 million in 2009, $2.1 million in 2008, and $1.9 million in 2007. The RKSP includes an Employee Stock Ownership Plan. In addition, we make contributions on behalf of each union employee to the Western States Office and Professional Employees Pension Fund, a multi-employer plan. Our contributions to the Western States Plan totaled $0.4 million in 2009, 2008 and 2007.

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 funds market value. The custodian provides the market values for investments directly owned.

US Large Cap Equity: Level 1 assets are 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.

US Small/Mid Cap Equity: 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 U.S. common stocks.

Table of Contents

Non-US Equity: 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: Level 1 assets are valued at the net asset value of the shares held by the plan at year end. This asset class includes investments primarily in emerging market common stocks.

Fixed Income: Level 1 assets are valued at the net asset value of the shares held by the plan at year end. This asset class includes investments primarily in investment grade debt and fixed income securities.

Real estate funds: Level 3 assets are 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. The real estate fund we are invested in normally provides for a quarterly distribution subject to 45 days advance notice of withdrawal. However, this fund is currently restricting withdrawals and has not made any distributions over the last six calendar quarters. No firm estimate can be made at this time when withdrawal requests will be honored. As of December 31, 2009, we have not submitted a withdrawal request.

Absolute Return Strategy: Level 2 assets are 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 of funds. 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, 2009 we have not submitted a withdrawal request.

Real Return Strategy: Level 1 assets are valued at the net asset value of the shares held by the plan at year end. 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: Level 2 assets are valued at the net asset value of the shares held by the plan at year end. This asset class 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. Furthermore, 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.

Our Plan's assets are invested in various investment securities. 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.

Table of Contents

The following table presents the Plan assets, including outstanding receivables and liabilities, of the Retirement Trust as of December 31, 2009.

Investments, in thousands	Level 1	Level 2	Level 3	Total
US Large Cap Equity	$ 35,266	$ -	$ -	$ 35,266
US Small/Mid Cap Equity	-	27,953	-	27,953
Non-US Equity	25,395	13,456	-	38,851
Emerging Markets Equity	1,021	-	-	1,021
Fixed Income	36,682	-	-	36,682
Real Estate	-	-	12,936	12,936
Absolute Return Strategy	-	30,097	-	30,097
Real Return Strategy	13,592	-	-	13,592
Cash and cash equivalents	-	4,614	-	4,614
Total investments	$ 111,956	$ 76,120	$ 12,936	$ 201,012
Receivables				
Accrued interest and dividend income				$ 200
Due from broker for securities sold				400
Total receivables				$ 600
Liabilities				
Due to broker for securities purchased				$ 300
Total investment in Retirement Trust				$ 201,312

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, 2009:

Thousands	Level 3 Assets Real estate Funds
January 1, 2009 balance	$ 18,494
Transfers into level 3	-
Transfers out of level 3	-
Total gains or (losses):	
Included in earnings	-
Included in other comprehensive income or regulatory accounts	(5,558)
Purchases, sales, issuances and settlements:	
Purchases	-
Issuances	-
Sales	-
Settlements	-
December 31, 2009 balance	$ 12,936

Table of Contents

8. INCOME TAXES:

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	2009	2008	2007
Income taxes at federal statutory rate	$ 42,627	$ 38,571	$ 41,495
Increase (decrease):			
Current state income tax, net of federal tax benefit	5,568	4,100	4,566
Amortization of investment and energy tax credits	(593)	(646)	(881)
Differences required to be flowed-through by regulatory commissions	(116)	(704)	(704)
Gains on company and trust-owned life insurance	(1,195)	(767)	(679)
Other - net	380	124	263
Total provision for income taxes	$ 46,671	$ 40,678	$ 44,060
Federal statutory tax rate	35.0 %	35.0 %	35.0 %
Increase (decrease):			
Current state income tax, net of federal tax benefit	4.6 %	3.7 %	3.9 %
Amortization of investment and energy tax credits	-0.5 %	-0.6 %	-0.7 %
Differences required to be flowed-through by regulatory commissions	-0.1 %	-0.6 %	-0.6 %
Gains on company and trust-owned life insurance	-1.0 %	-0.7 %	-0.6 %
Other - net	0.3 %	0.1 %	0.2 %
Effective tax rate	38.3 %	36.9 %	37.2 %

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

Thousands	2009	2008	2007
Current			
Federal	$ 6,221	$ (7,970)	$ 41,086
State	2,300	(437)	7,764
	8,521	(8,407)	48,850
Deferred			
Federal	31,937	42,862	(4,107)
State	6,213	6,223	(683)
	38,150	49,085	(4,790)
Total provision for income taxes	$ 46,671	$ 40,678	$ 44,060
Total income taxes paid	$ 10,000	$ 12,300	$ 56,215

Table of Contents

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	2009	2008	2007
Regulated utility:			
Current	$ 871	$ (13,034)	$ 43,587
Deferred	40,829	48,790	(3,856)
Deferred investment and energy tax credits	(593)	(646)	(713)
	41,107	35,110	39,018
Non-utility business segments:			
Current	7,650	4,627	5,263
Deferred	(2,086)	941	(53)
Deferred investment and energy tax credits	-	-	(168)
	5,564	5,568	5,042
Total provision for income taxes	$ 46,671	$ 40,678	$ 44,060

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

Thousands	2009	2008
Deferred tax liabilities:		
Plant and property	$ 231,768	$ 183,462
Regulatory adjustment for income taxes paid	2,169	2,374
Regulatory income tax assets	72,721	69,948
Regulatory liabilities	13,506	8,145
Non-regulated deferred tax liabilities	-	426
Total	320,164	264,355
Deferred tax assets:		
Regulatory assets	(14,436)	(4,335)
Unfunded pension and postretirement obligations	(3,925)	(2,709)
Non-regulated deferred tax assets	(2,860)	(471)
Loss and credit carryforwards	-	(1,557)
Total	(21,221)	(9,072)
Deferred income tax liabilities - net	298,943	255,283
Deferred investment tax credits	1,955	2,548
Deferred income taxes and investment tax credits	$ 300,898	$ 257,831

We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2009.

Table of Contents

The following is a reconciliation of the change in our deferred tax balance for the year ended December 31, 2009:

Thousands	2009
Deferred tax expense, above, including investment tax credit	$ 38,743
Increase in differences required to be flowed-through	6,292
Decrease in minimum pension liability included in AOCI	(1,215)
Decrease in deferred taxes associated with asset held for sale	(160)
Decrease in deferred investment tax credits	(593)
Change in deferred income tax accounts	$ 43,067

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.

In February 2009, the American Recovery and Reinvestment Act of 2009 (Act) was signed into law. This Act provides a 50 percent bonus tax depreciation deduction for qualified property acquired or constructed and placed in service in 2009. The extra 50 percent depreciation deduction in the first year is an acceleration of depreciation deductions that otherwise would have been taken in the later years of an asset's recovery period. The accelerated depreciation provisions provided by the Act expired at December 31, 2009. We estimate that the bonus depreciation deduction will defer the payment of approximately $12.9 million of federal income taxes during 2009 to future periods.

In December 2008, we filed an application with the Internal Revenue Service (IRS) requesting a change in our tax accounting method to expense routine repair and maintenance costs for gas pipelines that are currently being capitalized and depreciated for book purposes. The IRS consented to our request in August 2009, and we recognized a tax deduction of approximately $59 million on our 2008 tax return as a result of this method change, which resulted in a federal refund of approximately $21 million during the fourth quarter of 2009.

For the year ended December 31, 2008, we reported an estimated net operating loss (NOL) for federal and Oregon income tax purposes of $19.2 million and $23.8 million, respectively, primarily due to the effects of accelerated tax depreciation provided by the Economic Stimulus Act. As a result of the change in our tax accounting method for repair and maintenance costs discussed above as well as our increased pension contribution, our NOL for federal and Oregon income tax purposes was $89.0 million and $87.2 million on our 2008 federal and Oregon tax returns, respectively. The federal NOL was carried back to 2006 for a refund of taxes paid in prior years, while the Oregon NOL has been carried forward to reduce current and future taxable income. We anticipate that we will be able to use all loss carryforwards in future years. The 2008 Oregon NOL would expire in 2023 if not used in earlier years.

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, 2009, we had no uncertain tax positions.

An IRS examination of the 2006 through 2008 consolidated federal income tax returns commenced during the fourth quarter of 2009. The IRS completed its examination of the 2002 through 2004 audit cycle in the second quarter of 2006 and completion of the 2006 through 2008 federal income tax returns is expected during 2010.

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

Table of Contents

9. PROPERTY AND INVESTMENTS:

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

Thousands, except percentages	2009 Amount	2009 Weighted Average Depreciation Rate	2008 Amount	2008 Weighted Average Depreciation Rate
Transmission and distribution	$ 1,862,837	2.7%	$ 1,810,747	3.3%
Utility storage	119,477	2.2%	116,035	2.5%
General	104,880	5.0%	100,838	3.2%
Intangible and other	86,848	6.0%	77,650	9.0%
Gas stored long-term	14,134	0.0%	14,133	0.0%
Utility plant in service	2,188,176	2.9%	2,119,403	3.4%
Construction work in progress	27,936		23,585	
Total utility plant	2,216,112		2,142,988	
Less accumulated depreciation	(682,060)		(659,123)	
Utility plant-net	$ 1,534,052		$ 1,483,865	

Accumulated depreciation does not include the accumulated provision for asset removal costs of $238.8 million and $223.7 million at December 31, 2009 and 2008, respectively. These accrued asset removal costs are reflected on the balance sheets as regulatory liabilities (see Note 1, “Plant and Property and Accrued Asset Removal Costs”).

The following table summarizes our investments in non-utility plant at December 31:

Thousands, except percentages	2009 Amount	2009 Weighted Average Depreciation Rate	2008 Amount	2008 Weighted Average Depreciation Rate
Non-utility storage	$ 60,792		$ 60,515	
Other	5,292		4,886	
Non-utility plant in service	66,084	2.2%	65,401	2.5%
Construction work in progress	80,538		9,105	
Total non-utility plant	146,622		74,506	
Less accumulated depreciation	(10,540)		(9,314)	
Non-utility plant - net	$ 136,082		$ 65,192	

Table of Contents

The OPUC and WUTC approved our filed depreciation study and our request to change the amortization of our regulatory tax asset account balance on pre-1981 plant. These approvals specifically authorized the implementation of new depreciation rates in Oregon and Washington, with a corresponding decrease to customer billing rates effective January 1, 2009. The new regulatory tax amortization schedule on pre-1981 assets, with a corresponding increase to customer rates, became effective January 1, 2009 in Washington and November 1, 2009 in Oregon. The implementation of the new rates decreases depreciation expense and increases income tax expense, both of which are offset on an annualized basis by a corresponding change in utility operating revenues. FERC also approved the application of these new depreciation rates for our interstate gas storage assets in May 2009, and the new rates were made effective as of January 1, 2009. Due to the depreciation rate decreases, total depreciation and amortization expense in 2009 decreased by $9.3 million, or 13 percent.

The following table summarizes other long-term investments, including financial investments in life insurance policies accounted for at fair value and equity investments in certain partnerships and joint ventures accounted for under the equity or cost methods, at December 31:

Thousands	2009	2008
Life insurance investments	$ 49,327	$ 35,427
Note receivable	609	518
Investments in gas pipeline joint ventures	15,154	15,214
Other	2,275	2,072
Total other investments	$ 67,365	$ 53,231

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

Investments in Gas Pipeline Joint Ventures. A wholly-owned subsidiary of Financial Corporation, KB Pipeline Company, owns a 10 percent interest in an 18-mile interstate natural gas pipeline. In 2007, we also entered into an agreement with TransCanada's Gas Transmission Northwest (GTN) for the purpose of designing, permitting, constructing and owning a gas pipeline that would connect GTN's interstate transmission pipeline to our local gas distribution system to serve markets in Oregon and the western United States. As of December 31, 2009, our investment balance in Palomar was $14.1 million, primarily related to planning and permitting.

Variable Interest Entities. According to authoritative guidance on variable interest entities, we determine whether consolidation is required for entities known as variable interest entities over which control is achieved through means other than voting rights or for entities that do not have sufficient equity investment at risk to permit financing its activities without additional financial support. We currently have a variable interest in Palomar, which is accounted for as an equity investment and not consolidated as it was determined we are not the primary beneficiary. See Note 2.

Table of Contents

10. DERIVATIVES:

We have entered into swaps, options and combinations of options for the purchase of natural gas and for the forecasted issuance of fixed-rate debt that qualify as derivative instruments under accounting for derivative instruments and hedging activities. We primarily use derivative financial instruments to manage commodity prices related to our natural gas requirements and to manage interest rate risk exposure related to our long-term debt issuances.

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 the physical contracts. Derivatives entered into prudently for future gas years prior to our annual PGA filing receive regulatory deferral treatment. Derivative contracts entered into for core utility customer requirements after the annual PGA rate was set on November 1, 2009, are subject to the PGA incentive sharing mechanism, whereby 90 percent of the changes in fair value are deferred as regulatory assets or liabilities and the remaining 10 percent is recorded to the income statement for contracts not qualifying for hedge accounting and to other comprehensive income for contracts qualifying for hedge accounting.

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. These forward contracts qualify for cash flow hedge accounting treatment under accounting for derivatives and hedges. The mark-to-market adjustment at December 31, 2009 was an unrealized gain of $0.3 million. This unrealized gain is subject to regulatory deferral and, as such, was recorded as a derivative asset, which is offset by recording a corresponding amount to a regulatory liability account.

The unrealized mark-to-market value at December 31, 2009 for all derivative contracts outstanding was a net loss of $15.5 million consisting of the following: a $15.8 million unrealized loss on natural gas commodity hedge and derivative contracts, and a $0.3 million unrealized gain on the foreign exchange forward contracts.

Derivative hedge contracts are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2009, 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 for derivatives and hedges to determine the hedge effectiveness of interest rate swaps. The ineffectiveness for all other derivative contracts is determined using the dollar offset method. The effectiveness test applied to financial derivatives is dependent on the type of derivative and its use. There was no ineffectiveness as of December 31, 2009.

We do most of our hedging for the upcoming gas year prior to the start of that gas year and include the hedge prices in our annual PGA filing. We hedge our anticipated year-round sales volumes based on normal weather. We entered the 2009-10 gas year (November 1, 2009 – October 31, 2010) hedged at a targeted level of approximately 75 percent, 60 percent financially and 15 percent physically through gas storage. Additionally we entered the gas year between 10 and 15 percent financially hedged for the 2010-11 and 2011-12 gas years. We have Board authorization to hedge price risk for up to 100 percent of our gas supplies for the next gas contract year.

The remaining 2009-10 gas year volumes hedged at December 31, 2009 include 522.7 million therms of financial hedges and 66.1 million therms of gas storage hedges.

Table of Contents

The following table discloses the balance sheet presentation of our derivative instruments as of December 31, 2009 and 2008:

	Fair Value of Derivative Instruments			
	2009		2008	
Thousands	Current	Non-Current	Current	Non-Current
Assets: (1)				
Natural gas commodity	$ 6,214	$ 843	$ 4,592	$ 146
Foreign exchange	290	-	-	-
Total	$ 6,504	$ 843	$ 4,592	$ 146
Liabilities: (2)				
Natural gas commodity	$ 19,643	$ 3,193	$ 136,290	$ 9,734
Interest rate	-	-	-	11,912
Foreign exchange	-	-	445	-
Total	$ 19,643	$ 3,193	$ 136,735	$ 21,646

(1) Unrealized fair value gains are classified under current- or non-current assets as fair value of non-trading derivatives.
(2) Unrealized fair value losses are classified under current- or non-current liabilities as fair value of non-trading derivatives.

The following table discloses the income statement presentation for the unrealized gains and losses from our derivative instruments for the years ended December 31, 2009 and 2008. It also illustrates that all of our derivative instruments are related to regulated utility operations and derivative gains and losses are deferred to balance sheet accounts in accordance with regulatory accounting.

	2009		2008		
Thousands	Natural gas commodity (1)	Foreign exchange (3)	Natural gas commodity (1)	Interest rate (2)	Foreign exchange (3)
Cost of sales	$ (15,779)	$ -	$ (141,286)	$ -	$ -
Other comprehensive income (loss)	-	290	-	(10,375)	(445)
Gain (loss) recognized in income (ineffective portion)	-	-	-	(1,537)	-
Less:					
Amounts deferred to regulatory accounts on balance sheet	15,779	(290)	141,286	11,912	445
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 interest rate hedge contracts is recorded in other comprehensive income (loss) and reclassified to regulatory deferral accounts on the balance sheet.
(3) Unrealized gain (loss) from foreign exchange forward purchase contracts is recorded in other comprehensive income (loss), and reclassified to regulatory deferral accounts on the balance sheet.

Table of Contents

The gross derivative liability excludes the netting of collateral. We had no collateral posted with our counterparties at December 31, 2009. We attempt to minimize our potential exposure to collateral calls by our counterparties to manage our liquidity risk. Based on our current credit rating, most counterparties allow us credit limits that range from $15 million to $25 million before collateral postings are required. We measure our collateral call exposure under credit support agreements, which generally contain credit limits based on our credit ratings. We also could be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Estimated collateral calls are included in the table below. The following table discloses the estimates with and without potential adequate assurance calls, using outstanding derivative instruments at December 31, 2009, based on current gas prices and with various credit rating scenarios for NW Natural.

Thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ -	$ -	$ -	$ -	$ 7,760
Without Adequate Assurance Calls	$ -	$ -	$ -	$ -	$ 7,760

During 2009 we realized net losses of $187.9 million from the settlement of natural gas hedge contracts, which was recorded as increases to the cost of gas, compared to realized net gains of $35.1 million during 2008, which was recorded as decreases 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 settled our $50 million interest rate swap in March 2009 concurrent with our issuance of the underlying long-term debt and realized a $10.1 million effective hedge loss, which will be amortized to interest expense over the term of the debt.

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 in order for a counterparty to meet our credit requirements.

Our financial derivatives policy requires counterparties to have an 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. 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 at-risk trading limits. The duration of our credit risk for all outstanding derivatives currently does not extend beyond October 31, 2012.

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.

Table of Contents

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 nonperformance 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, 2009.

The following table provides the fair value hierarchy of our derivative assets and liabilities as of December 31, 2009 and 2008:

Thousands	Fair Value Measurements	
Hierarchy	Description of Derivative Inputs	Fair Value, net
Level 1	Quoted prices in active markets	$ -
Level 2	Significant other observable inputs	(15,489)
Level 3	Significant unobservable inputs	-
		$ (15,489)

11. COMMITMENTS AND CONTINGENCIES:

Lease Commitments

We lease land, buildings and equipment under agreements that expire in various years through 2095. Rental expense under operating leases was $5.3 million, $4.7 million and $4.6 million for the years ended December 31, 2009, 2008 and 2007, respectively. The table below reflects the future minimum lease payments due under non-cancelable leases at December 31, 2009. Such payments total $45.0 million for operating leases. The net present value of payments on capital leases less imputed interest was $1.0 million. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, vehicles and computer equipment.

Thousands	2010	2011	2012	2013	2014	Later years
Operating leases	$ 4,162	$ 4,155	$ 4,279	$ 4,317	$ 4,641	$ 23,423
Capital leases	582	269	95	16	-	-
Minimum lease payments	$ 4,744	$ 4,424	$ 4,374	$ 4,333	$ 4,641	$ 23,423

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, 2009:

Thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements

2010	$	145,305	$	86,064	$	4,157
2011		37,819		74,966		3,464
2012		23,640		54,910		-
2013		16,741		47,425		-
2014		13,951		23,554		-
Thereafter		-		268,553		-
Total		237,456		555,472		7,621
Less: Amount representing interest		5,370		145,559		63
Total at present value	$	232,086	$	409,913	$	7,558

Table of Contents

Our total payments of fixed charges under capacity purchase agreements in 2009, 2008 and 2007 were $84.6 million, $85.7 million and $90.1 million, respectively. Included in the amounts were reductions for capacity release sales of $4.2 million for 2009, $5.0 million for 2008 and $5.3 million for 2007. 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 accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study 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 environmental site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. We regularly review our remediation 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 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 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.

To the extent reasonably estimable, we estimate the costs of 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 a better estimate within this range of probable cost, we record the liability at the lower end of this range. It is likely that changes in these estimates 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 compliance alternatives. The status of each of the sites currently under investigation is provided below.

Gasco site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (the 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 remedial alternatives for the most contaminated portion of the Gasco site. In May 2007, we completed a revised Upland Remediation Investigation Report and submitted it to the ODEQ for review. In November 2007 we submitted a Focused Feasiblity Study to ODEQ for groundwater source control which ODEQ conditionally approved in March 2008. During the third quarter of 2009, we signed an Order on Consent with the Environmental Protection Agency (EPA) which requires the design of a final remedial action for the Gasco site sediments. During 2009, our net liability increased $33.4 million, primarily based on the current baseline methodology for potential remediation for the new sediments project. We have a net liability accrued of $53.5 million at December 31, 2009 for the Gasco site, which is estimated 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.

Siltronic site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic site). We are currently implementing an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ. The net liability accrued at December 31, 2009 for the Siltronic site is $1.2 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.

Table of Contents

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 the area adjacent to the Gasco and Siltronic sites. The Portland Harbor site was listed by the EPA as a Superfund site in 2000 and we were notified that we were 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. 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 currently expected in 2010. The EPA and the Lower Willamette Group are conducting focused studies on approximately nine miles of the lower Willamette River, including the 5.5-mile segment previously studied by the EPA. In 2008, we received a revised estimate and updated our estimate for additional expenditures related to RI/FS development and environmental remediation. In August 2008, we signed a cooperative agreement to participate in a phased natural resource damage assessment, with the intent to identify what, if any, additional information is necessary to estimate further liabilities sufficient to support an early restoration-based settlement of natural resource damage claims. As of December 31, 2009, we have a net liability accrued of $8.9 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.

In April 2004, we entered into an Administrative Order on Consent providing for early action removal of a deposit of tar in the river sediments adjacent to the Gasco site. We completed the removal of the tar deposit in the Portland Harbor in October 2005, and on November 5, 2005 the EPA approved the completed project. The total cost of removal, including technical work, oversight, consultant fees, legal fees and ongoing monitoring, was about $9.9 million. To date, we have paid $9.4 million on work related to the removal of the tar deposit. As of December 31, 2009, we have a net liability accrued of $ 0.5 million for our estimate of ongoing costs related to the tar deposit removal.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (the 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 2007, we received notice that this site was added to the ODEQ’s list of sites where releases of hazardous substances have been confirmed and 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, 2009, we have recorded an estimated liability 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. Although it is 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 it could be managed separately from the Portland Harbor site under ODEQ authority. As of December 31, 2009, we accrued an estimated liability of $0.5 million for the study of the site, which will include investigation of sediments and provide a report of historical upland activities. 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.

Table of Contents

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

Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at December 31, 2009 and 2008:

	Current Liabilities		Non-Current Liabilities	
Thousands	2009	2008	2009	2008
Gasco	$ 9,841	$ 6,012	$ 43,659	$ 14,071
Siltronic	653	682	593	332
Portland Harbor	2,114	277	7,272	13,642
Central Service Center	5	-	511	526
Front Street	72	-	436	294
Other	-	-	123	80
Total	$ 12,685	$ 6,971	$ 52,594	$ 28,945

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 authorized us to accrue interest 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, this authorization has been extended through January 2010. We have requested another extension through January 2011, and that request is currently pending.

On a cumulative basis, we have recognized a total of $101.4 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $36.1 million has been spent to date and $65.3 million is recorded as an outstanding liability. At December 31, 2009, we had a regulatory asset of $106.0 million, which includes $36.7 million of total paid expenditures to date, $59.8 million for additional environmental costs expected to be paid in the future and accrued interest of $9.5 million. We believe the recovery of these deferred charges is probable through the regulatory process. We intend to pursue recovery of an insurance receivable and environmental regulatory deferrals from insurance carriers under our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We consider insurance recovery of most of our environmental costs probable based on a combination of factors including: a review of the terms of our insurance policies; the financial condition of the insurance companies providing coverage; a review of successful claims filed by other utilities with similar gas manufacturing facilities; and Oregon law that allows an insured party to seek recovery of "all sums" from one insurance company. We have initiated settlement discussions with a majority of our insurers. In the event that settlements cannot be reached, we may pursue other legal remedies. We continue to anticipate that our overall insurance recovery effort will extend over several years.

Table of Contents

As such we have classified our regulatory assets for environmental cost deferrals as non-current. The following table summarizes the non-current regulatory assets relating to environmental sites at December 31, 2009 and 2008:

	Non-Current Regulatory Assets	
Thousands	2009	2008
Gasco	$ 69,607	$ 30,707
Siltronic	2,974	2,327
Portland Harbor	31,500	31,791
Central Service Center	550	545
Front Street	910	338
Other	507	396
Total	$ 106,048	$ 66,104

Legal Proceedings

We are subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings, including the matter described below, cannot be predicted with certainty, we do not expect that the ultimate disposition of any of these matters will have a material adverse 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 and discovery is ongoing. We do not expect that the ultimate disposition of this matter will have a material adverse effect on our financial condition, results of operations or cash flows.

12. SUBSEQUENT EVENTS:

We have been involved in litigation with the Oregon Department of Revenue (ODOR) over whether natural gas inventories and appliance inventories held for resale are required to be taxed as personal property. This was appealed to and presented before the Oregon Supreme Court in 2009. In January 2010, the Oregon Supreme Court unanimously ruled in our favor, stating that these inventories were exempt from property tax. The ODOR has until March 11, 2010 to file a Motion for Reconsideration with the Oregon Supreme Court. We are entitled to a refund of approximately $5.0 million, plus accrued interest, for property taxes paid on gas inventories beginning with the 2002-03 tax year and appliance inventories beginning with the 2005-06 tax year. We will recognize this gain as income in 2010.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Quarter ended					
Thousands, except per share amounts	March 31	June 30	Sept. 30	Dec. 31	Total	
2009						
Operating revenues	$437,355	$149,060	$116,854	$309,442	$1,012,711	
Net operating revenues	142,639	65,919	48,626	119,703	376,887	
Net income (loss)	47,363	3,086	(6,733)	31,406	75,122	
Basic earnings (loss) per share	1.79	0.12	(0.25)	1.19	2.83	(1)
Diluted earnings (loss) per share	1.78	0.12	(0.25)	1.18	2.83	(1)
2008						
Operating revenues	$387,694	$191,254	$109,702	$349,205	$1,037,855	
Net operating revenues	132,423	62,572	43,549	117,671	356,215	
Net income (loss)	43,168	3,297	(10,120)	33,180	69,525	
Basic earnings (loss) per share	1.63	0.12	(0.38)	1.25	2.63	(1)
Diluted earnings (loss) per share	1.63	0.12	(0.38)	1.25	2.61	(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.

Table of Contents

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

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
	Balance at beginning of period	Additions		Deductions	Balance at end of period
Thousands (year ended Dec. 31)		Charged to costs and expenses	Charged to other accounts	Net Write-offs	
2009					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,927	$4,201	$-	$4,003	$3,125
2008					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,890	$3,145	$-	$3,108	$2,927
2007					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$3,033	$2,978	$-	$3,121	$2,890

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 December 31, 2009, 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, 2009 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 9A.

Management's Report on Internal Control Over Financial Reporting and the Report of Independent Registered Public Accounting Firm appear under Item 8.

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

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 27, 2010 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 27, 2010 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2009	Positions held during last five years
Gregg S. Kantor	52	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	48	Senior Vice President and Chief Financial Officer (2004-).
Margaret D. Kirkpatrick	55	Vice President and General Counsel (2005-); Partner in the law firm of Stoel Rives LLP (1991-2005).
Lea Anne Doolittle	54	Senior Vice President (2008-); Vice President, Human Resources (2000-2007).
J. Keith White	56	Vice President, Business Development and Energy Supply (2007-); Managing Director, Gas Operations and Wholesale Services (2005-2006); Managing Director and Chief Strategic Officer (2003-2005).
David R. Williams	56	Vice President, Utility Services (2007-); Director of Utility Operations, Districts and managed Labor Relations (2004-2006).
Grant M. Yoshihara	54	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
C. Alex Miller	52	Vice President, Finance and Regulation (2009-); Assistant Treasurer (2008-); General Manager of Rates and Regulatory Affairs (2002-2009).

Stephen P. Feltz	54	Treasurer and Controller (1999-).
MardiLyn Saathoff	53	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).

Each executive officer serves successive annual terms; present terms end on May 27, 2010. 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 applicable to all employees, including our chief executive officer, chief financial officer and principal accounting officer, and a Financial Code of Ethics that applies to senior financial employees, both of which are available on our website at www.nwnatural.com. We intend to disclose on our website at www.nwnatural.com any amendments to or waivers of our Code of Ethics for executive officers.

Table of Contents

ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation" and "Report of the Organization and Executive Compensation Committee on Executive Management Compensation" contained in our definitive Proxy Statement for the May 27, 2010 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2009 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, 2009 (see Note 4 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	77,500	n/a	228,858
Restated Stock Option Plan	484,935	$ 39.57	810,650
Employee Stock Purchase Plan	24,530	$ 35.54	170,388
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)2	5,529	n/a	n/a
Directors Deferred Compensation Plan (DDCP)2	69,001	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)3	91,801	n/a	n/a
Total	753,296		1,209,896

The information captioned "Beneficial Ownership of Common Stock by Directors and Executive Officers" contained in our definitive Proxy Statement for the May 27, 2010 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, 2009, the number of shares shown in column (a) would increase by 77,500 shares and the number of shares shown in column (c) would decrease by 155,000 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.

Table of Contents

(3) Effective January 1, 2005, the EDCP and DDCP were replaced by the Deferred Compensation Plan for Directors and Executives (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 27, 2010 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2009 and 2008 Audit Firm Fees" in the Company's definitive Proxy Statement for the May 27, 2010 Annual Meeting of Shareholders is hereby incorporated by reference.

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 113.

Table of Contents

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 26, 2010 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 President and Chief Executive Officer	Principal Executive Officer and Director	February 26, 2010
/s/ David H. Anderson David H. Anderson Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 26, 2010
/s/ Stephen P. Feltz Stephen P. Feltz Treasurer and Controller	Principal Accounting Officer	February 26, 2010
/s/ Timothy P. Boyle Timothy P. Boyle	Director)))	
/s/Martha L. Byorum Martha L. Byorum	Director)))	
/s/ John D. Carter John D. Carter	Director)))	
/s/ Mark S. Dodson Mark S. Dodson	Director)))	February 26, 2010
/s/ Tod R. Hamachek Tod R. Hamachek	Director)))	
/s/ Jane L. Peverett Jane L. Peverett	Director))	

	)	
/s/ George J. Puentes	Director	)
George J. Puentes	)	
	)	
/s/ Kenneth Thrasher	Director	)
Kenneth Thrasher	)	
	)	
/s/ Russell F. Tromley	Director	)
Russell F. Tromley	)	

Table of Contents

EXHIBIT INDEX
To
Annual Report on Form 10-K
For Fiscal Year Ended
December 31, 2009

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).

Table of Contents

*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 10.1 to Form 8-K dated June 1, 2007, 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 institutions 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.
*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.
*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).
*10a.(1)	Replacement Firm Transportation Agreement, dated July 31, 1991, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(2) to Form 10-K for 1992, File No. 0-994).
*10a.(2)	Firm Transportation Service Agreement, dated November 10, 1993, between the Company and Pacific Gas Transmission Company

(incorporated herein by reference to Exhibit 10j.(2) to Form 10-K for 1993, File No. 0-994).

*10a.(3) Service Agreement, dated June 17, 1993, between Northwest Pipeline GP and the Company (incorporated herein by reference to Exhibit 10j.(3) to Form 10-K for 1994, File No. 0-994).

Table of Contents

*10a.(4)	Firm Transportation Service Agreement, dated June 22, 1994, between Pacific Gas Transmission Company and the Company (incorporated herein by reference to Exhibit 10j.(5) to Form 10-K for 1995, File No. 0-994).
*10a.(5)	Firm Service Agreement between the Company and Westcoast Energy Inc., dated as of April 1, 2003 (incorporated herein by reference to Exhibit 10 to Form 10-Q for quarter ended March 31, 2003, File No. 0-994).
*10a.(6)	Service Agreement Amendment, dated February 12, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(7) to Form 10-K for 2007, File No. 1-15973).
*10a.(7)	Service Agreement, dated February 8, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(8) to Form 10-K for 2007, File No. 1-15973).
*10a.(8)	Agreement between the Company and March Point Cogeneration Company, dated February 8, 2008 (incorporated herein by reference to Exhibit 10j.(9) to Form 10-K for 2007, File No. 1-15973).
*10a.(9)	Firm Transportation Service Agreement, dated October 22, 1993, between the Company and Pacific Gas Transmission Company (incorporated herein by reference to Exhibit 10j.(10) to Form 10-K for 2008, File No. 1-15973).
*10a.(10)	Service Agreement (100310), dated January 21, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(11) to Form 10-K for 2008, File No. 1-15973).
*10a.(11)	Service Agreement, dated January 21, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(12) to Form 10-K for 2008, File No. 1-15973).
*10a.(12)	Service Agreement (Gas Storage Service), dated January 12, 1994, between the Company and Northwest Pipeline Corporation (incorporated herein by reference to Exhibit 10j.(13) to Form 10-K for 2008, File No. 1-15973).
*10a.(13)	Service Agreement (100309), dated January 21, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(14) to Form 10-K for 2008, File No. 1-15973).
*10a.(14)	

	Service Agreement (100308), dated January 12, 1994, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(15) to Form 10-K for 2008, File No. 1-15973).
*10a.(15)	Service Agreement, dated January 20, 1995, between the Company and NOVA Gas Transmission Ltd (incorporated herein by reference to Exhibit 10j.(16) to Form 10-K for 2008, File No. 1-15973).
*10a.(16)	Service Agreement, dated November 1, 2004, between the Company and TransCanada PipeLines Limited (incorporated herein by reference to Exhibit 10j.(17) to Form 10-K for 2008, File No. 1-15973).

Table of Contents

*10a.(17)	Service Agreement, dated October 24, 2008, between Foothills Pipe Lines Ltd. and the Company (incorporated herein by reference to Exhibit 10j.(18) to Form 10-K for 2008, File No. 1-15973).
*10a.(18)	Amendment and Restatement of Firm Transportation Service Agreement, dated November 1, 2004, between Terasen Gas Inc. and the Company (incorporated herein by reference to Exhibit 10j.(19) to Form 10-K for 2008, File No. 1-15973)..
12	Statement re computation of ratios of earnings to fixed charges.
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.
10c.	Supplemental Executive Retirement Plan, effective September 1, 2004 restated 2010.
*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 From 10-K

	for 2006, File No. 1-15973).
10h.	Form of Restated Stock Option Plan Agreement.
*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 From 10-K for 2008, File No. 1-15973).

Table of Contents

*10j.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10(f). to From 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, 2010.
10l.	Form of Indemnity Agreement as entered into between the Company and each director and certain executive officers.
10l.(1)	Form of Indemnity Agreement as entered into between the Company and certain executive officers.
*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 25, 2010.
10o.	Form of Agreement to Recoupment Provisions of Executive Annual Incentive Plan, effective as of January 1, 2010.
*10p.	Form of Change in Control Severance Agreement between the Company and each executive officer (incorporated herein by reference to Exhibit 10(o). to From 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 July 26, 2001 (incorporated herein by reference to Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2001, File No. 0-994).
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 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated February 21, 2007, File No. 1-15973).
*10u.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (incorporated herein by reference to

Exhibit 10w.(2) to Form 10-K for 2007, File No. 1-15973).

*10v.	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).
*10w.	Restricted Stock Bonus Agreement with an executive officer dated July 26, 2006 (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 28, 2006, File No. 1-15973).

Table of Contents

*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 as indicated