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.

Table of Contents

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.

- 4-

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		