NORTHWEST NATURAL GAS CO
Form 10-K
February 29, 2008
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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, 2007

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. [ ]

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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 definition of accelerated filer, large 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 29, 2007, the registrant had 26,815,203 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 $1,226,580,437.

At February 25, 2008, 26,408,248 shares of the registrant s Common Stock (the only class of Common Stock) were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

List documents incorporated by reference and the Part of the Form 10-K into which the document is incorporated.

Portions of the Proxy Statement of Company, to be filed in connection with the 2008 Annual Meeting of Shareholders, are incorporated by reference in Part III.

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NORTHWEST NATURAL GAS COMPANY

Annual Report to Securities and Exchange Commission

on Form 10-K

For the Fiscal Year Ended December 31, 2007

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GLOSSARY OF TERMS

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

Basic earnings per share: net income for a period, divided by the average number of shares of common stock outstanding during that period.

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. One hundred thousand Btu s equal one therm.

Core utility customers: residential, commercial and industrial firm service customers on our distribution system.

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

Diluted earnings per share: net income for a period, divided by the average number of shares of stock that would be outstanding assuming the issuance of common shares for all existing stock based compensation plans with a dilutive impact during the reporting period.

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.

Gas storage: a means of holding gas in facilities for future delivery, either through injection into an underground storage field, or storing it in the form of liquefied natural gas.

General rate case: a periodic filing with state regulators to establish equitable rates and balance the

interests of all classes of customers and our shareholders.

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.

Open Season: A period of time during which prospective customers express binding or non-binding interest in pipeline or gas storage services.

Purchased Gas Adjustment (PGA): a regulatory mechanism for annually adjusting customer rates due to changes in the cost to acquire 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.

Return on invested capital (ROIC): a measure of profitability calculated by dividing net income before interest expense by average long-term invested capital.

Sales service: service provided to a customer that receives both natural gas supply and transportation of that gas from the regulated 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 regulated utility only for use of the distribution system to transport it.

Underground gas storage: storage of natural gas by injection into underground wells; historically gas is withdrawn during the winter heating season or during periods of high gas prices.

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

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NORTHWEST NATURAL GAS COMPANY

PART I

ITEM 1. BUSINESS

General

Northwest Natural Gas Company was incorporated under the laws of Oregon in 1910. Our company and its predecessors have supplied gas service to the public since 1859. Since September 1997, we have been doing business as NW Natural.

Business Segments

Local Gas Distribution

We are principally engaged in the distribution of natural gas in Oregon and southwest Washington. In this report our principal business segment is referred to as local gas distribution or utility. Local gas distribution involves purchasing gas from producers, transporting the gas over interstate pipelines from the supply basins to our service territory, and reselling the gas to customers at 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 96 percent of our consolidated assets and 87 percent of our consolidated net income in 2007 are 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 southern Washington counties bordering the Columbia River. Gas service is provided in 123 cities and neighboring communities in 15 Oregon counties, as well as in 14 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 2007, we had approximately 590,000 residential customers, 61,000 commercial customers and 900 industrial sales customers. Approximately 90 percent of our customers are located in Oregon and 10 percent are in Washington. Industries served include: pulp, paper and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation. No individual customer or industry accounts for a significant portion of our industrial revenues.

Gas Storage

The gas storage business segment includes NW Natural s underground natural gas storage services to interstate and large intrastate customers using NW Natural s storage and related transportation capacity that is in excess of core utility customer requirements. Additionally, an independent energy marketing company provides asset optimization services to the utility under a contractual arrangement, the results of which are included in this business segment. Approximately 3

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percent of our consolidated assets and 12 percent of consolidated net income in 2007 are related to the gas storage business segment. For each of the years ended December 31, 2007, 2006, and 2005, this business segment derived a majority of its revenues from multi-year contracts with less than 10 customers. The total working gas capacity of the Mist underground gas storage facility has been increased from 14 Bcf to around 16 Bcf to reflect an expansion in certain reservoir pools. Of this capacity, the gas storage business has access to about 7 Bcf of capacity while the utility has access to the remaining 9 Bcf.

Pre-tax income from gas storage and third-party optimization activities 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 deferred to a regulatory account for rate credits 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.

***Interstate Gas Storage*.** This part of the business segment provides bundled firm or interruptible gas storage services at Mist and related transportation services on NW Natural s system to and from Mist to interstate pipeline interconnections for several interstate customers. The interstate storage services and maximum rates for these services are authorized by the Federal Energy Regulatory Commission (FERC). The storage capacity used by this business has been developed 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. The firm storage service terms and conditions mirror the firm interstate storage service, except that these customers are located and served in Oregon under an OPUC-approved rate schedule that includes service and site-specific qualifications.

***Third Party 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. See Part II, Item 7., Results of Operations Business Segments Other than Local Gas Distribution Gas Storage.

Other

We have other investments, including assets in NNG Financial Corporation (Financial Corporation) (see Subsidiaries, below), a Boeing 737-300 aircraft under lease to Continental Airlines but currently held for sale, and investments in development projects such as Gill Ranch and Palomar Pipeline (see Subsidiaries, below). Less than 1 percent of our consolidated assets and about 1 percent of 2007 consolidated net income are related to activities in the Other business segment.

Subsidiaries

Financial Corporation

Financial Corporation, a wholly-owned subsidiary incorporated in Oregon, holds non-utility financial investments. Financial Corporation has one active, wholly-owned subsidiary, KB Pipeline Company (KB Pipeline), which owns a 10 percent interest in an 18-mile interstate natural gas pipeline.

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In October 2007, Financial Corporation s limited partnership investments in two wind power electric generation projects in California were sold. In addition, in December 2007, one of Financial Corporation s two low-income housing project investments reached the end of its contract period and the partnership investment was disposed of pursuant to the original terms of the agreement.

Gill Ranch

In September 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop a new underground natural gas storage facility at Gill Ranch near Fresno, California. We formed a wholly-owned subsidiary of NW Natural to develop and operate the facility. Gill Ranch Storage, LLC, will initially own 75 percent of the project, and PG&E will own 25 percent. The new storage facility is expected to provide approximately 20 Bcf of underground gas storage capacity, and will include 25 miles of transmission pipeline, when the initial phase is completed. We estimate our share of the total cost for the initial phase of development to be between $150 million and $160 million over the next three years, which represents 75 percent of the estimated project cost. We conducted an open season to gauge interest in the storage facility from October 2007 to December 2007, and the results indicated a strong level of interest in gas storage at Gill Ranch from potential storage customers. We expect to file an application with the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity in mid-2008 and, if granted, Gill Ranch will be subject to CPUC regulation with respect to rates and various regulatory approvals, including but not limited to securities issuance, lien grants and sales of property. We expect the initial phase of Gill Ranch to be in-service by late 2010.

Gas Supply, Storage and Transportation Capacity

General

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 system 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 movement of customers between bundled sales service and transportation-only service. Sensitivity analyses are performed 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 we supplement during periods of peak demand with gas from storage facilities either owned by or contractually committed to us.

Gas Acquisition Strategy

Our goals in purchasing gas for our core utility market consist of:

- ***Reliability*** Ensuring a gas resource portfolio that is sufficient to satisfy core utility customer requirements under design-day weather conditions, as defined in our Integrated Resource Plan (see Regulation and Rates Integrated Resource Plan, below);
- ***Lowest reasonable cost*** Applying strategies to acquire gas supplies at the lowest reasonable cost to utility customers;
- ***Price stability*** Making use of physical assets (e.g. gas storage) and financial instruments (e.g. financial hedge contracts such as price swaps) to manage price variability; and
- ***Cost recovery*** Managing gas purchase costs prudently to minimize the risks associated with regulatory review and recovery of gas acquisition costs.

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To achieve those goals, we employ a gas purchasing strategy based upon a diversity of supply, liquidity, price risk management, asset optimization and regulatory alignment, as discussed in more detail below.

Diversity of Supply. There are three means by which we diversify our gas supply acquisitions: regional supply basin, contract types and contract duration.

The following table represents the actual and target purchase percentages from the regional sources of gas supply available to us:

Regional Supply Basin

Region	2007 Actual	2007-2012 Target
Alberta	41%	45%
British Columbia	27%	30%
U.S. Rockies	32%	25%
Mist gas field	<1%	<1%
Total	100%	100%

We believe that gas supplies available in the western United States and Canada are adequate to serve our core utility customers for the foreseeable future, and that our cost of gas generally will track market prices.

We typically enter into gas purchase contracts for:

- year-round baseload supply;
- additional baseload supply for November March (winter heating season);
- winter heating season contracts where we have the option to call on all, some or none 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 contracts, 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. In general, we try to maintain a diversified portfolio of purchase arrangements. For example, we use a variety of multi-year contract durations to avoid having to re-contract all supplies every year. See Core Utility Market Basic Supply, below.

Liquidity. 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. There are four general methods that we currently use for managing gas commodity price risk:

- negotiating fixed prices directly with gas suppliers;
- negotiating financial instruments that exchange the floating price in a physical supply contract for a fixed price (referred to as price swaps);

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- negotiating financial instruments that set a ceiling or floor price, or both, on a floating price contract (referred to as calls, puts, and collars); and
- buying gas and injecting it into storage. 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 to our own activities to economically manage our gas supply costs, we contract with an independent energy marketing company to more fully capture optimization opportunities.

Regulatory Alignment. Mechanisms for gas cost recovery are designed to be fair and balanced for 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 cost recovery through:

- the use of purchased gas adjustment (PGA) mechanisms approved by the OPUC and WUTC (see Part II, Item 7., Results of Operations Regulation and Rates Rate Mechanisms, below);
- aligning customer and shareholder interests through incentive sharing mechanisms, such as the PGA and asset optimization mechanisms; 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 pipelines to transport the gas to our distribution system and gains or losses related to hedge contracts entered into in connection with the supply of gas to core customers. While the rates for pipeline transportation and storage services are subject to federal regulation, the purchase price of gas is not.

Supply cost. Natural gas commodity prices increased dramatically over the last six years due to growing demand for natural gas (especially for power generation), surging alternative fuel prices, and the impact of hurricane activity that affected oil and natural gas production in the Gulf of Mexico. We are in a favorable position with respect to gas production because of the proximity of our service territory to supply basins in British Columbia and the Rocky Mountains, where some growth in gas production is expected to continue for the foreseeable future.

Transportation cost. Pipeline transportation rates charged by our pipeline suppliers had been stable until recently when two of the five major pipelines used by NW Natural filed with the FERC for significant rate increases in 2006, which were implemented in 2007. Pipeline transportation rate increases are generally recoverable through our state-approved PGA mechanisms.

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, by entering into natural gas commodity-based financial hedge contracts, and by crediting gas costs with margin revenues derived from off-system sales of commodity supplies and released transportation capacity in periods when core utility customers do not fully utilize firm pipeline transportation capacity and gas supplies.

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Managing the Cost of Gas

We manage natural gas commodity price risk through an active hedging program in which we enter into either fixed price physical supply contracts or fixed price financial derivatives contracts. The financial 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 this program, we enter into commodity swaps, puts, calls or collars for the coming year and up to three years into the future. Gains or losses from financial commodity hedge contracts are treated as reductions or increases to the cost of gas. The intended effect of this program is to lock in prices for a majority of our gas supply portfolio for the following gas contract year, including at least 50 percent of the expected heating season purchases, based on the market prices and forecasted purchase requirements prevailing at the time the financial agreements are entered into.

In addition to the volumes for which prices are locked in through financial hedges, we also use gas storage as a physical hedge. We purchase and inject about 15 percent of our annual gas supply requirements into storage during the summer when gas prices are historically lower. That gas 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 eliminates the need for additional upstream pipeline capacity and provides significant cost savings.

Source of Supply 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. To assure reliability, we base our plans on being able to meet the supply needs on the coldest weather experienced over the last 20 years in our service territory. We start with the coldest overall heating season and then modify it to include the coldest weather day over that same 20-year period. This coldest design day is the maximum anticipated demand on the natural gas distribution system during a 24-hour period, which currently assumes weather at an average temperature of 12 degrees Fahrenheit. We assume that all interruptible customers will be curtailed on the design day. Our projected sources of delivery for design day firm utility customer sendout total approximately 8.86 million therms. We are currently capable of meeting 63 percent of our firm customer design day requirements with storage and peaking supply sources located within or adjacent to our service territory. Optimal utilization of storage and peaking facilities on our design day reduces the 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. 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 planning (IRP) process (see Regulation and Rates Integrated Resource Plan, below).

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The following table shows the sources of supply that are projected to be used to satisfy the design day sendout for the 2007-2008 winter heating season:

Projected Sources of Supply for Design Day Sendout

Sources of Supply	Therms (in millions)	Percent
Firm contracts	3.25	37
Off-system storage	1.06	12
Mist underground storage (utility only)	2.30	26
LNG storage	1.80	20
Recall agreements	0.45	5
Total	8.86	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 are sufficient to satisfy the needs of existing customers and are positioned to grow, as needed, to meet requirements in future years.

Core Utility Market Basic Supply

We purchase gas for our core utility customers from a variety of suppliers located in the western United States and Canada. As shown above, about 65 to 70 percent of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. At January 1, 2008, we had 23 firm contracts with 14 suppliers and remaining terms ranging from three months to eight years, which provide for a maximum of 2.2 million therms of firm gas per day during the peak winter heating season and 1.2 million therms per day during the remainder of the year. These contracts have a variety of pricing structures and purchase obligations. During 2007, we purchased 809 million therms of gas under the following contract durations:

Contract Duration (primary terms)	Percent of Purchases
Long-term (one year or longer)	53%
Short-term (more than one month, less than a year)	11%
Spot (one month or less)	36%
Total	100%

We regularly renew or replace our expiring long-term gas supply contracts with new agreements from 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), three suppliers each provide between 11.1 percent and 12.5 percent of our average daily contract volumes. Firm year-round supply contracts have remaining terms ranging from one to eight years. All term gas supply contracts use price formulas tied to monthly index prices, primarily at the NIT trading point in Alberta. 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 2007, new short-term purchase agreements were entered into with six suppliers. These agreements have a variety of pricing structures and provide for a total of up to 990,000 therms per day during the 2007-2008 heating season. We intend to enter into new purchase agreements in 2008 for equivalent volumes of gas with our existing or other similar suppliers, as needed, to replace contracts that will expire during 2008.

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

We continue to purchase gas from a non-affiliated producer in the Mist gas field in Oregon. The production area is situated near our underground gas storage facility. The price for this gas is tied to our weighted average cost of gas. Current production is approximately 10,000 therms per day from about 17 wells, supplying 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 either owned or contractually committed to us. Gas is generally purchased and stored during periods of low demand for use 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 transportation contract demand costs and to purchase gas for storage during the summer months when prices are historically lower.

Underground storage. We provide daily and seasonal peaking from our underground gas storage facility in the Mist gas storage field. Including the latest expansions in 2007, this facility has a maximum daily deliverability of 5.1 million therms and a total working gas capacity of about 16 Bcf. In September 2004, we completed our South Mist pipeline extension project, which is a utility transmission pipeline from our Mist gas storage field to growing portions of our distribution service area. Also in 2004, a total of 400,000 therms per day of Mist storage capacity, which had been available for the non-utility gas storage business, was recalled and committed to use for core utility customers. This was the first instance of returning capacity that had been developed in advance of core utility customers needs for interstate gas storage services under the regulatory agreement with the OPUC. Under this agreement, storage capacity is recalled as needed and added to utility rate base, at our original cost less accumulated depreciation, with a corresponding rate increase to customers to reflect the cost of service. No additional recalls of Mist capacity were required in 2005, 2006 or 2007. The core utility market now has 2.3 million therms per day of deliverability and approximately 9 Bcf of working gas committed from the Mist storage facility. As storage capacity is recalled to serve core utility customers, new storage capacity may be developed.

We also have contracts with Northwest Pipeline Corporation (Northwest Pipeline) for firm gas storage services from an underground storage facility at Jackson Prairie near Chehalis, Washington, and an LNG facility at 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.

LNG. We own and operate two LNG storage facilities in our service territory that liquefy gas during the summer months for storage until 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. We also have contracts with one electric generator and two industrial customers that together provide an additional 52,000 therms per day of year-round upstream capacity, plus 450,000 therms per day of recallable capacity and supply. Two of these three contracts renew from year to year, while the third will expire in 2010.

Transportation

Dependence on a 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 is bi-directional as it 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 Rocky Mountain supply basins. The need for pipeline transportation diversity has been underscored by past Northwest Pipeline ruptures and the resulting federal order in 2003 that required Northwest Pipeline to replace its 26-inch mainline from the Canadian border to our service territory. 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 currently evaluating a potential pipeline project 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 and owning this proposed pipeline. If constructed, this pipeline would provide an alternate transportation path for gas purchases in Alberta that currently move through the Northwest Pipeline system (See Part II, Item 7., 2008 Outlook Strategic Opportunities Pipeline Diversity).

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

Transportation Agreements. The largest of our transportation agreements with Northwest Pipeline extends through 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 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 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 previously extended into 2009 for approximately 350,000 therms per day of firm transportation capacity from the U.S. Rocky Mountain region. In February 2008, we extended the term of this contract through 2044. Also in February 2008, we executed an agreement with a third party to take assignment of their firm gas supply transportation contract starting no earlier than 2012 and no later than 2017, with a term extending through 2046. This contract consists of 120,000 therms per day on Northwest Pipeline from the U.S. Rocky Mountain region.

In addition, we have firm long-term pipeline transportation contracts with two other major transporters. A contract with Spectra Energy Corporation (formerly Westcoast Energy, Inc.) 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

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Pipeline at the U.S./Canadian border. A contract with Terasen Gas 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 with Terasen Gas is matched with companion contracts for pipeline capacity on the TransCanada BC system and NOVA system in British Columbia and Alberta, allowing purchases to be made from the gas fields of Alberta, Canada.

Regulation and Rates

We provide local distribution gas utility service in Oregon and Washington and, accordingly, we are subject to state regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. Local distribution service in Oregon represents about 91 percent of the utility s revenues, while Washington represents the remaining 9 percent (see Part II, Item 8., Note 1).

We periodically file general rate case and rate tariff requests with the OPUC and WUTC to change the rates we charge our customers. 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 the future, we may be subject to regulation in other states resulting from our strategic investments. For further information, see Part II, Item 7., Results of Operations Regulatory Matters, below.

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. Our most recent acknowledged integrated resource plans in Oregon and Washington were filed in 2005. Elements of the plans included:

- an evaluation of supply and demand resources;
- the consideration of uncertainties in the planning process and the need for flexibility to respond to changes;
- a primary goal of least cost service; and
- consistency with state energy policy.

Although the OPUC s order acknowledging the integrated resource plan does not constitute ratemaking approval of any specific resource acquisition or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. Elements of our current integrated resource plan demonstrate that the continued development of the Mist underground gas storage facility is the least-cost option for serving customer growth. We filed a draft IRP with the WUTC in the first quarter of 2007, and we expect to file a draft IRP with the OPUC by the end of the first quarter of 2008.

Additions to Infrastructure

We expect a high level of capital expenditures for additions to infrastructure over the next five years, reflecting projected customer growth, technology, distribution system replacement, improvement and reinforcement projects and the development of additional gas storage facilities. In 2008, utility capital expenditures are estimated to be between $90 and $100 million, and business development investments could amount to between $15 and $25 million. For the years 2008-2012,

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capital expenditures for the utility are estimated at between $500 and $600 million, while business development investments will depend largely on decisions about potential opportunities in storage and pipeline development projects. Despite a slower annual growth rate than in past years, our growth rate during 2007 continued to be above the national average for gas utilities.

Pipeline Safety

The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 Act) was signed into law in December 2006. The 2006 Act mandates certain standards related to our distribution lines, including the development of an integrity management program for those distribution pipelines. Distribution pipeline safety rules required by the 2006 Act are expected to be final in 2009.

The Pipeline Safety Improvement Act of 2002 (2002 Act) and related regulations require gas transmission pipeline operators to identify lines located in High Consequence Areas (HCAs) and develop integrity management programs to periodically inspect the pipelines and make repairs or replacements as necessary to ensure the ongoing safety of the pipelines. The legislation and related pipeline safety regulations require us to complete inspection of 50 percent of the highest risk pipelines located in our HCAs within the first five years, and the remaining covered pipelines within 10 years, of the date of enactment. We are also required to re-inspect the covered pipelines every seven years from the date of the previous inspection for the life of the pipelines. We continued to achieve our milestones, completing the required inspection of the top 50 percent highest risk transmission pipelines in 2007. We are currently on track to meet the next milestone to complete the inspection of all transmission pipelines in HCAs by December 2012.

In 2005, we assumed responsibilities as operator of an approximately 60-mile pipeline that transports gas from Northwest Pipeline to Coos County, Oregon. The pipeline is owned by Coos County, and we have an agreement to operate the pipeline and related lateral pipelines that continues yearly until terminated by either party. The pipeline safety requirements of the 2002 Act apply to us as operator of that pipeline.

In 2001, we entered into a stipulation with the OPUC for an enhanced pipeline safety program that includes an accelerated bare steel replacement program and a geo-hazard safety program. The bare steel program accelerates the replacement of our bare steel piping over 20 years instead of 40 years and allows us to receive rate treatment for costs associated with the program exceeding $3 million per year. The geo-hazard component of the safety program expired on December 31, 2006. It included the identification, assessment and remediation of risks to pipe infrastructure created by landslides, washouts, earthquakes or similar occurrences, and allowed us to receive deferred rate treatment for costs associated with the program. Although the regulatory authority for the geo-hazard safety program expired, we received approval from the OPUC to defer the costs up to $2.5 million associated with a specific remediation project, which was completed in 2007.

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 gas-to-gas competition from third-party sellers of natural gas commodity.

Competition among these forms of energy is based on price, reliability, efficiency and performance, which can change from year-to-year based on market conditions, technology and legislative policy.

Residential and Commercial Markets

The relatively low market saturation of natural gas in residential single-family dwellings in our service territory, estimated at approximately 50 percent, together with the price advantage of natural gas compared with electricity in most areas and our operating convenience over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2007, 14,560 net residential customers (after subtracting disconnected or terminated services) were added, primarily from single- and multi-family new construction, but also due to the conversion of existing residential housing from oil, electric or propane appliances to natural gas. The net increase of all new customers added in 2007 was 15,428. This represents a growth rate of 2.4 percent, which is well above the national average for local gas distribution companies as reported by the American Gas Association.

Industrial Markets

As a result of the deregulation and restructuring of the energy markets during the past two decades, the natural gas industry, including producers, interstate pipelines and local gas distribution companies, has undergone significant changes. Traditionally, local gas distribution companies sold a bundled product that included both the natural gas commodity and delivery to the end-use customer s meter. However, beginning in the late 1980s, large industrial customers sought to achieve savings by procuring their own supplies of natural gas from producers and contracting with pipelines and local gas distribution companies for transportation of natural gas to their facilities. These changes were intended to promote competition where it was economically beneficial to consumers.

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

The OPUC and WUTC have approved transportation tariffs under which we may contract with customers to deliver customer-owned gas. Transportation tariffs available to industrial customers are priced at our cost of providing transportation service. Generally, we are unaffected financially if industrial customers transport customer-owned gas rather than purchasing gas directly from us, as long as they remain on a tariff or contract with the same quality of service. This is because 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 different levels or qualities of service, and these choices can positively or negatively affect margin. The relative level and volatility of prices in the natural gas commodity markets, along with the availability of interstate pipeline capacity to ship customer-owned gas and the cost structure embedded in our industrial rates, are among the primary factors that have caused some industrial customers to alternate between sales and transportation service or between higher and lower qualities of service.

We redesigned our industrial rates in Oregon and Washington as part of our general rate cases in 2003 and 2004, respectively, in order to better reflect relative costs of service and to become more competitive in the industrial market. In August 2006, the OPUC and WUTC approved tariff changes to the service options for our industrial accounts. The changes set out additional parameters that give us more certainty in the level of gas supplies we will need to purchase in order to serve this customer group. The parameters include an annual election cycle period, special pricing provisions for out-of-cycle changes and the requirement that 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 under our regulatory tariff.

We have negotiated special transportation service agreements with some of our largest industrial customers. These special 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.

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 evolving 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 level. 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); and an area adjacent to the Gasco and the Siltronic sites along a segment of 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). We do not expect that the ultimate resolution of these matters will have a material adverse effect on our financial condition or results of operations; however, if it is determined that both the insurance recovery and future rate recovery of such costs are not probable, then the costs 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 Part II, Item 8, Note 12, to the accompanying Consolidated Financial Statements for a further discussion of potential environmental responses and related costs.

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Future Environmental Issues

We recognize that our business is likely to face 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 the proposed international standards (Kyoto Protocol), proposed federal legislation and proposed or enacted state actions to develop statewide or regional programs, each of which have imposed or would impose reductions in greenhouse gas emissions. The outcome of federal and state climate change initiatives cannot be determined at this time, but these initiatives could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could result in increased costs associated with operating and maintaining our facilities, could increase other costs to our business and could impact the prices we charge our customers. Because natural gas is a fossil fuel with low carbon content, it is possible that future carbon constraints could create additional demand for natural gas, both for electric production and direct use in homes and businesses.

We continue taking steps to address future environmental 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. In 2008, NW Natural s President was appointed to the newly formed 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 (see Part II, Item 7., Regulation and Rates Rate Mechanisms Smart Energy Program).

Employees

At December 31, 2007, our workforce consisted of 738 members of the Office and Professional Employees International Union (OPEIU), Local No. 11, AFL-CIO, and approximately 400 management level and other non-bargaining employees. Our labor agreement (Joint Accord) with members of OPEIU that covers wages, benefits and working conditions, extends to May 31, 2009.

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.W., 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 Web site (http://www.sec.gov) that contains reports, proxy statements and other information filed electronically by us. In addition, we make available on our website (http://www.nwnatural.com), free of charge, 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. Our Corporate Governance

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Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about us are also available on 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.

Our Chief Executive Officer certified to the New York Stock Exchange (NYSE) on June 1, 2007 that, as of that date, he was not aware of any violation by the company of NYSE s corporate governance listing standards, and that we had filed with the SEC, as exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the year ended December 31, 2006, the certificates of the Chief Executive Officer and the Chief Financial Officer certifying the quality of NW Natural s internal control over financial reporting and public disclosures. For the year-ended December 31, 2007, the certificates of the Chief Executive Officer and the Chief Financial Officer are filed with this report as Exhibits 31.1 and 31.2.

ITEM 1A. RISK FACTORS

Our business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents we file with the SEC.

Regulatory risk. *The rates we charge customers for gas distribution services are established by the OPUC and the WUTC, and the maximum rates for interstate gas storage services are approved by FERC. The failure of these regulatory authorities to approve rates which provide for recovery of our costs and an adequate return on invested capital may adversely impact our financial condition and results of operations.*

The rates charged to customers must be approved by the applicable regulatory commission. The 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. We expect to continue to make capital expenditures to expand and improve our distribution and storage systems. The failure of any regulatory commission to approve on a timely basis requested rate increases to recover increased costs or to allow an adequate return could adversely impact our financial condition and results of operations. In addition, amounts required to be refunded to customers in accordance with Oregon s automatic regulatory adjustment for income taxes paid could have a material adverse impact on our financial conditions and results of operations.

Gas price risk. *Higher natural gas commodity prices and fluctuations in the price of gas may adversely affect our earnings.*

In recent years, natural gas commodity prices have been volatile primarily due to growing demand, especially for power generation, and stagnant North American gas production. In Oregon and in Washington, the utility has PGA tariffs which provide for annual revisions in rates resulting from changes in the cost of purchased gas. 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 that 33 percent of any difference between the actual purchased gas costs and the actual recoveries of gas costs in rates be recognized as current income or expense. Accordingly, higher gas costs than those assumed in setting rates can adversely affect our results of operations.

The OPUC has begun a formal review of the PGA process which will cover portfolio requirements, incentive sharing levels and filing requirements, among other items. The review is expected to be completed in 2008. Implementation of any changes to the PGA mechanism is likely to become effective with the 2008 PGA filing.

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.

Hedging risk. *Our risk management policies and hedging activities cannot eliminate the risk of commodity price movements and other financial market risks may expose us to additional liabilities for which rate recovery may be disallowed.*

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 and other financial market risks. We attempt to manage these exposures and mitigate our risk through enforcement of established risk limits and risk management procedures, including hedging activities, in accordance with our Financial Derivatives Policy. These risk limits and risk management procedures may not always work as planned and cannot entirely eliminate the risks associated with hedging. We also have credit exposure to financial derivative counterparties. Our Financial Derivatives Policy requires counterparties to have a minimum 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. These practices are subject to regulatory review and, if found to be imprudent, could be disallowed, which could adversely affect our financial condition and results of operations.

Customer growth risk. *Our results of operations may be negatively affected if we are unable to sustain customer growth rates.*

Our earnings growth and results of operations have largely been dependent upon the sustained growth of our residential and commercial customer base. If we are unable to sustain customer growth rate levels at or above the national average, our results of operations may be negatively affected. A number of factors could negatively impact our ability to sustain growth, such as a downturn in the economy, reduced housing starts and competition.

Risk of competition. *Our gas distribution business is subject to increased competition with other energy sources.*

To the extent that competition increases, our profit margins may be negatively affected. In the residential market, we compete primarily with suppliers of electricity, fuel oil and propane. We also compete with suppliers of electricity and fuel oil for commercial applications. In the industrial market, we compete with all forms of energy suppliers. Competition among these forms of energy is based on price, reliability, efficiency and performance.

Higher natural gas prices have eroded, or in some cases eliminated, the competitive price advantage of natural gas over other energy sources. Also, technological improvements in other energy sources could erode our competitive advantage. If natural gas prices continue to rise relative to other energy sources, then our ability to attract new customers could be significantly affected, which could have a negative impact on our customer growth rate and results of operations.

Single transportation pipeline risk. *We rely on a single pipeline for the transportation of gas to our service territory.*

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We are largely dependent on a single, bi-directional pipeline for transportation of gas into our service territory. Our results of operations may be negatively impacted if there is a rupture in the pipeline and we incur costs associated with actions taken to mitigate disruption of service.

Business development risk. *The construction, startup and operation of our business development projects may involve unanticipated changes or delays that could negatively impact our financial condition and results of operations.*

The startup, construction and operation of business development projects involve many risks, including: the inability to obtain required governmental permits and approvals; startup and construction delays; construction cost overruns; competition; inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts; changes in market prices; and operating cost increases. Such unanticipated events could negatively impact our results of operations. These risks apply to our current business development activities, including Palomar Pipeline and the Gill Ranch storage facility in California.

Environmental risk. *Certain of our properties and facilities may pose environmental risks requiring remediation, the cost of which could adversely affect our results of operations and financial condition. Also, management expects that future legislation may impose carbon constraints to address global climate change.*

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 some of these estimated costs. To the extent we are unable to recover these costs in rates or through insurance, we would be required to reduce our regulatory asset which could 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 uncertain outcomes.

We cannot predict with certainty the amount or timing of future expenditures related to environmental investigation and remediation that may be required 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. There are also 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 a material adverse effect on our results of operations, particularly if those costs are not fully recoverable from customers.

With respect to global climate change, there are a number of legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address climate change could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could result in increased costs associated with operating and maintaining our facilities, could increase other costs to our business and could impact the prices we charge our customers.

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

A large portion of the utility s margin is derived from sales to space heating residential and commercial customers during each winter heating season. Current rates are based on an assumption of average weather. In Oregon, the effects of warmer or colder weather on utility margin are reduced through the operation of our weather normalization mechanism, and partially reduced by our conservation tariff in months when weather normalization is not in effect. However, customers in Oregon may elect to opt out of the weather normalization mechanism, and less than 10 percent of those customers have opted out on an annualized basis. In addition, approximately 10 percent of our residential and commercial customers are in Washington where we do not have a weather normalization mechanism or conservation tariff. As a result, we are not fully protected against warmer than average weather, 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.*

Higher gas costs and rates may result in increased conservation by customers, which can decrease sales and adversely affect results of operations. The OPUC authorized our conservation tariff, which is designed to recover lost margin due to changes in residential and commercial customers consumption patterns. The conservation tariff is intended to adjust for increases or decreases in consumption attributable to annual changes in commodity costs or periodic changes in general rates and for deviations between actual and expected usage. The conservation tariff expires in October 2012. The failure of the OPUC to extend the conservation tariff in the future could adversely affect our financial condition and results of operations. 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, such as leaks, accidents, mechanical problems, fires, storms, landslides and other adverse weather conditions and hazards, which could cause substantial financial losses. In addition, 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 substantial losses. The occurrence of any of these events may not be covered by our insurance policies or recoverable through rates, which could adversely affect our financial condition and results of operations.

Business continuity risk. *We may be adversely impacted by extreme events to which we are not able to promptly respond to and repair our system.*

Extreme events (e.g. terrorism act or national disaster) that target or impact our natural gas distribution, transmission and storage facilities could result in a disruption in our ability to meet customer requirements. These events may also disrupt capital markets and our ability to raise capital, or impact our suppliers or our customers directly. We maintain emergency planning and training programs to remain ready to respond to extreme events. A slow response to extreme events may have an adverse affect on earnings as customers could be without gas for an extended period of time.

Economic risk. *Changes in the economic outlook, including rates of inflation and capital market conditions may have a negative impact on our financial condition and results of operations.*

Our business relies on capital markets to finance our construction costs and other capital expense requirements, and to refund maturing debt, that cannot by funded by operating cash flows. Changes in the economy that impact our ability to access the capital markets at competitive rates may negatively impact our ability to make strategic capital investments. Market disruptions and downgrades of our debt credit ratings may increase our cost of borrowing or negatively impact our ability to access financial markets.

Workforce risk. *Our business is heavily dependent on being able to attract and retain qualified employees and to maintain a competitive cost structure with market-based salaries and employee benefits.*

Our gas distribution business is subject to a variety of workforce risks, including being able to attract and retain qualified employees, being able to transfer the knowledge and expertise of an aging workforce to new employees as older workers retire and being able to reach collective bargaining agreements with the union that represents about 65 percent of our workers.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Our natural gas distribution system consists of approximately 13,700 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 lease expires on May 31, 2018. Resource centers are maintained on owned or leased premises at convenient points in the distribution system. We own LNG storage facilities in Portland and near Newport, Oregon.

We hold interests in approximately 8,500 net acres of underground natural gas storage and approximately 1,400 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.

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.

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.

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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

See Part II, Item 8., Note 12 to Consolidated Financial Statements, Commitments and Contingencies Legal Proceedings.

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, 2007.

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PART II

ITEM 5. MARKET FOR THE REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(A) Our common stock is listed and trades on the New York Stock Exchange under the symbol NWN.

The high and low trades for our common stock during the past two years were as follows:

	2007		2006	
Quarter Ended	High	Low	High	Low
March 31	$ 46.34	$ 39.79	$ 36.57	$ 32.83
June 30	52.85	44.05	37.04	33.30
September 30	49.37	40.98	40.08	35.81
December 31	50.89	44.28	43.69	38.53

The closing quotations for our common stock on December 31, 2007 and December 29, 2006 were $48.66 and $42.44, respectively.

(B) As of December 31, 2007, there were 7,863 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	2007	2006
February 15	$ 0.355	$ 0.345
May 15	0.355	0.345
August 15	0.355	0.345
November 15	0.375	0.355
Total per share	$ 1.440	$ 1.390

The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. It is the intention of the Board of Directors to continue to pay cash dividends on our common stock on a quarterly basis. However, the declaration and amount of future dividends will be dependent upon our earnings, cash flows, financial condition and other factors.

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(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, 2007:

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			1,905,528	$ 26,938,905
10/01/07-10/31/07	1,126	$ 46.48	132,300	(6,138,707)
11/01/07-11/30/07	19,984	$ 49.54	61,100	(2,843,169)
12/01/07-12/31/07	1,736	$ 47.90	25,600	(1,224,381)
Total	22,846	$ 49.27	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2007, 20,873 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 1,973 shares of our common stock were purchased in the open market during the quarter under equity-based programs. During the three months ended December 31, 2007, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) On May 25, 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of NW Natural s common stock through a repurchase program that has been extended annually. The purchases are made in the open market or through privately negotiated transactions. In April 2006, the Board increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million. In April 2007, the Board extended the program through May 31, 2008 and increased the authorization from 2.6 million shares to 2.8 million shares and increased the dollar limit from $85 million to $100 million. During the three months ended December 31, 2007, 219,000 shares of our common stock were purchased pursuant to this program. Since the program s inception through December 31, 2007, we have repurchased 2,124,528 shares of common stock at a total cost of $83.3 million.

On September 28, 2007, we entered into a Stock Purchase Plan Engagement Agreement with our broker that established a trading plan for our repurchase program that qualified for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Exchange Act. That agreement expired on November 9, 2007.

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ITEM 6. SELECTED FINANCIAL DATA

Thousands, except per share amounts and ratio of earnings to fixed charges	For the year ended December 31, 2007	2006	2005	2004	2003
Utility operating revenues:					
Residential sales	$ 555,312	$ 536,468	$ 471,502	$ 383,067	$ 328,346
Commercial sales	298,800	290,666	250,287	200,424	176,336
Industrial - firm sales	54,567	66,986	64,507	45,259	33,578
Industrial - interruptible sales	74,876	93,107	100,740	55,380	23,655
Unbilled revenues[1]	-	-	-	-	14,474
Total gas sales revenues	983,555	987,227	887,036	684,130	576,389
Transportation	14,191	12,800	10,755	12,655	17,968
Regulatory adjustment for income taxes paid[2]	5,996	-	-	-	-
Other	12,228	161	2,862	4,160	7,627
Total gross utility operating revenues	1,015,970	1,000,188	900,653	700,945	601,984
Cost of gas sold	639,094	648,081	563,772	399,176	323,128
Revenue taxes	25,001	24,840	21,633	16,865	14,650
Utility operating revenues	351,875	327,267	315,248	284,904	264,206
Non-utility operating revenues	17,167	12,909	9,745	6,591	9,210
Net operating revenues	$ 369,042	$ 340,176	$ 324,993	$ 291,495	$ 273,416
Net income	$ 74,497	$ 63,415	$ 58,149	$ 50,572	$ 45,983
Redeemable preferred stock dividend requirements	-	-	-	-	294
Earnings applicable to common stock	$ 74,497	$ 63,415	$ 58,149	$ 50,572	$ 45,689
Average common shares outstanding:					
Basic	26,821	27,540	27,564	27,016	25,741
Diluted	26,995	27,657	27,621	27,283	26,061
Earnings per share of common stock:					
Basic	$ 2.78	$ 2.30	$ 2.11	$ 1.87	$ 1.77
Diluted	$ 2.76	$ 2.29	$ 2.11	$ 1.86	$ 1.76
Dividends paid per share of common stock	$ 1.44	$ 1.39	$ 1.32	$ 1.30	$ 1.27
Total assets - at end of period	$ 2,014,183	$ 1,956,856	$ 2,042,304	$ 1,732,195	$ 1,585,379
Long-term debt	$ 512,000	$ 517,000	$ 521,500	$ 484,027	$ 500,319
Ratio of earnings to fixed charges	3.92	3.40	3.32	3.02	2.84

(1) Unbilled revenues have been allocated by customer class for the years 2004 through 2007.

(2) Regulatory adjustment for income taxes paid is the result of the implementation of the utility regulation as described in Part II, Item 7., Results of Operations - Regulatory Matters - Regulatory Adjustment for Income Taxes Paid, and Comparison of Gas Distribution Operations - Regulatory Adjustment for Income Taxes Paid.

Certain amounts from prior years have been reclassified to conform, for comparison purposes, with the current financial statement presentation. These reclassifications had no impact on prior year consolidated results of operations.

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SELECTED FINANCIAL DATA (continued)

	For the year ended December 31,				
Thousands, except customer and gas cost per therm data	2007	2006	2005	2004	2003
Capitalization - at end of period					
Common stock equity	$ 594,751	$ 599,545	$ 586,931	$ 568,517	$ 506,316
Long-term debt	512,000	517,000	521,500	484,027	500,319
Total capitalization	$ 1,106,751	$ 1,116,545	$ 1,108,431	$ 1,052,544	$ 1,006,635
Gas sales and transportation deliveries (therms):					
Residential	398,960	382,665	371,538	352,356	343,534
Commercial	249,659	242,683	233,987	222,875	226,257
Industrial - firm	52,340	66,971	74,880	62,843	55,314
Industrial - interruptible	89,128	112,736	149,106	104,278	47,994
Unbilled therms[1]	-	-	-	-	12,099
Total gas sales	790,087	805,055	829,511	742,352	685,198
Transportation	424,882	387,594	328,056	389,514	414,554
Total volumes delivered	1,214,969	1,192,649	1,157,567	1,131,866	1,099,752
Customers (average for period):					
Residential	580,346	564,700	545,163	525,976	510,336
Commercial	60,749	59,889	58,914	57,973	56,504
Industrial - firm	634	650	666	629	362
Industrial - interruptible	189	197	201	178	98
Transportation	128	99	78	106	179
Total customers	642,046	625,535	605,022	584,862	567,479
Customer statistics:					
Heat requirements:					
Actual degree days	4,374	4,089	4,178	3,853	3,952
Percent colder (warmer) than average	3%	(4%)	(2%)	(10%)	(7%)
Average annual use per customer in therms:					
Residential	687	678	682	670	673
Commercial	4,110	4,052	3,972	3,844	4,004
Gas purchased cost per therm - net (cents)	75.00	75.37	71.42	56.60	46.99

(1) Unbilled therms have been allocated by customer class for the years 2004 through 2007.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management s assessment of Northwest Natural Gas Company s (NW Natural) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated activities for the three years ended December 31, 2007. References in this discussion to Notes are to the Notes to consolidated financial statements in this report.

The consolidated financial statements include the accounts of NW Natural, which principally consist of our regulated local gas distribution business, our regulated gas storage business, and other regulated and non-regulated investments primarily in energy-related businesses, including our wholly-owned subsidiaries, NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch). In this report, the term utility is used to describe our regulated gas distribution business, and the term non-utility is used to describe our gas storage business (gas storage) and our other non-regulated investments and business activities (other segment), including investments in a recently announced intrastate pipeline project in Oregon (Palomar Pipeline) (see 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).

Executive Summary

Highlights of 2007:

- Net income increased 17 percent to $74.5 million, and diluted earnings per share increased 21 percent to $2.76 per share;
- Net operating revenues from our utility increased 8 percent to $351.9 million;
- Net operating revenues from our gas storage business increased 33 percent to $17.0 million;
- Cash flow from operations increased 24 percent to $183.6 million, reflecting strong earnings and deferred gas cost savings;
- Ranked best in the West and second-best nationally in overall residential customer satisfaction among gas utilities according to a J.D. Power and Associates survey;
- Conservation tariff and weather normalization mechanisms were extended in Oregon through October 2012;
- Smart Energy Program, a carbon-offset billing option for customers, was implemented as the first program of its kind for a standalone gas company to address greenhouse gas emissions;
- Announced plans to develop investments in a natural gas transmission pipeline in Oregon and an underground gas storage facility in central California (see Strategic Opportunities, below);
- Mist storage capacity was expanded by 1.8 Bcf to approximately 16 Bcf; and,
- Quarterly common stock dividend rate increased 6 percent to $0.375 per share in the fourth quarter of 2007, making this the 52nd consecutive year of increasing dividends paid to shareholders.

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Our primary businesses consist of our regulated utility and gas storage. Factors critical to the success of the utility business include: maintaining a safe and reliable distribution system; acquiring an adequate supply of gas; providing distribution services at a competitive price; and being able to recover the operating and capital costs of the utility in the rates charged to customers. The utility 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 gas storage business segment include the ability to: develop additional storage capacity at competitive market prices; plan for the replacement of capacity that is expected to be recalled by the utility to serve its core customers in the future; and obtain timely and reasonable rate changes. Our gas storage businesses charge rates approved by the Federal Energy Regulatory Commission (FERC). The Gill Ranch project is expected to be subject to regulation by the California Public Utilities Commission (CPUC), if completed.

2008 Outlook

In 2008, management expects to focus on the following four areas:

Core Business Improvement. We plan to incorporate new technology into our operations while honing new processes established in the recent changes to our operating model. Our goal is to integrate and to streamline operations and provide our employees with tools to become even more effective and efficient.

Strategic Position. In our rapidly changing business environment, we will strive to continue achieving shareholder value while balancing the interests of our customers and communities. In doing so, we will continue to develop plans in response to potential climate change legislation as well as to address regulatory, business development and workforce challenges and opportunities.

Business Development. We intend to advance our key natural gas infrastructure investments, such as the Palomar Pipeline and Gill Ranch storage projects, while exploring new growth opportunities. See Strategic Opportunities, below.

Organizational Effectiveness. As employees are our most highly valued resource, we intend to continue to support our employees with well defined practices, training and technology to achieve our goals.

Issues, Challenges and Performance Measures

Managing the business in a period of gas price volatility. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility s core customers. Equally important, however, is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon the market outlook and our core utility s gas load forecast. We believe we have sufficient supplies of natural gas under contract to meet the needs of our core customers, but price increases could change our earnings outlook and our competitive advantage. If gas prices increase, it could affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses energy needs to alternative fuel sources. We continue to develop new gas acquisition strategies to manage gas prices and to efficiently meet market demands.

Customer growth. Our growth is largely driven by new residential construction, and while we expect to continue with a customer growth rate above the national average for local gas distribution companies due to the growing market in the Pacific Northwest, we have experienced a slowdown in new construction which is expected to continue through 2008. For the 12 months ended December 31, 2007, our annual growth rate was 2.4 percent, compared to 3.1 percent for the comparable period ended December 31, 2006. A prolonged slowdown in residential new construction could adversely impact our future results of operations.

Strategic Opportunities

Business Process Redesign. To address these economic and competitive challenges we will continue to evaluate our business processes and costs in our new operating model and to improve those processes where long-term efficiencies could be gained. We targeted a number of areas where we could restructure to gain efficiencies, including more centralization and more standardized processes. To date, we are on schedule to meet the target workforce reductions of 150 to 200 employees by late 2009. We are also currently completing the implementation of the first phase of a new integrated information system, with the second phase of the new system installation expected to commence early in 2008. These technology investments are expected to help facilitate additional business initiatives, as well as help to improve overall operational efficiencies throughout NW Natural.

Pipeline Diversity. In September 2006, we announced that we were evaluating a possible equity investment in a natural gas transmission pipeline that would connect TransCanada Gas Transmission Northwest s (GTN) interstate transmission line to our local gas distribution system (Palomar Pipeline). The proposed pipeline is intended to diversify our gas delivery options, including the enhancement of reliability for our customers by providing an alternate transportation path for, and an alternative gas supply source to, gas purchases in Alberta and, including the possible delivery of supplies from a liquefied natural gas (LNG) facility that is proposed on the Columbia River. In August 2007, we entered into an agreement with GTN for the purpose of developing, designing, permitting, constructing and owning the pipeline. During the planning and permitting phase we expect to contribute our 50 percent of the estimated $30 million for permitting and planning, which is anticipated to occur during the 2007-2009 period. We believe there is sufficient interest from potential pipeline users to warrant proceeding with the permitting phase of the project. We, along with GTN, will determine at a later date whether to proceed with development of the project beyond the permitting phase. If constructed, we estimate the total cost for the entire 220 mile pipeline to be between $600 million and $700 million. NorthernStar LLC, developer of a proposed Bradwood Landing LNG terminal on the Columbia River, may elect to take capacity on the Palomar Pipeline should the Bradwood Landing terminal and the Palomar Pipeline be constructed.

Gas Storage Development. In September 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. We formed Gill Ranch, a wholly owned subsidiary of NW Natural, to develop and operate the facility. Gill Ranch will initially own 75 percent of this storage project and PG&E will own 25 percent. The new storage facility is expected to provide approximately 20 Bcf of underground gas storage capacity, and will include 25 miles of transmission pipeline, when the initial phase is completed. We estimate our share of the total cost for the initial phase of development to be between $150 million and $160 million over the next three years, which represents 75 percent of the estimated total project cost. We conducted an open season to gauge interest in the storage facility from October 2007 to December 2007, and the results indicated a strong level of interest in gas storage at Gill Ranch from potential storage customers. We expect to file an application with the CPUC for a Certificate of Public Convenience and Necessity in mid-2008 and, if granted, Gill Ranch will be subject to CPUC regulation with respect, among other things, to rates, the issuance of securities, lien grants and sales of property. We expect the initial phase of Gill Ranch to be in-service by late 2010.

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Earnings and Dividends

Net income was $74.5 million, or $2.76 a diluted share, for the year ended December 31, 2007, compared to $63.4 million, or $2.29 a diluted share, and $58.1 million, or $2.11 a share, for the years ended December 31, 2006 and 2005, respectively. Returns on equity for these three years were 12.5 percent, 10.7 percent and 10.1 percent, respectively.

2007 compared to 2006:

Positive factors contributing to increased earnings were:

- increased utility volumes and sales to residential and commercial customers primarily from customer growth contributed $9.7 million to margin (see Results of Operations Comparison of Gas Distribution Operations, below);
- increased margin of $6.0 million from a regulatory adjustment for income taxes paid;
- increased margin from regulatory sharing of gas cost savings, up from $8.1 million in 2006 to $12.1 million in 2007, and from reversing temporary adjustments related to derivative contracts that settled in 2007, reflecting gains of $2.9 million in 2007 compared to losses of $2.9 million in 2006; and
- increased margin of $4.2 million from gas storage operations, primarily due to an expansion of firm storage capacity and higher revenue sharing from asset optimization.

Partially offsetting the above positive factors were:

- increased depreciation expenses of $3.9 million, primarily related to increased utility plant in service;
- increased operations and maintenance expense of $5.9 million, partially due to higher bonuses tied to improved performance results and an increase for certain strategic initiatives including maintenance projects and training; and
- increased income tax expense related to higher taxable income.

2006 compared to 2005:

Positive factors contributing to increased earnings were:

- increased utility volumes and net operating revenues (margin) from sales to residential and commercial customers due to 3.1 percent customer growth, plus extended coverage from the weather normalization and conservation mechanisms in Oregon, partially offset by weather that was 4 percent warmer than average and 2 percent warmer than 2005 (see Results of Operations Comparison of Gas Distribution Operations, below);
- increased margin from regulatory sharing of gas cost savings, from $4.2 million in 2005 to $8.1 million in 2006, partially offset by a $2.9 million temporary unrealized loss related to a derivative contract that settled and reversed in 2007; and
- increased gas storage margin over the prior year, primarily due to increased storage contract volumes and increased optimization revenue from the independent energy marketing company.

Partially offsetting the above positive factors were:

- increased property tax and depreciation expenses related to increased utility plant in service, which were partially covered by revenue increases approved in the 2006 Purchased Gas Adjustment (PGA) filings in Oregon and Washington;

- increased operations and maintenance expense related to higher bonuses tied to improved performance results and to employee severance charges tied to business redesign initiatives, partially offset by lower payroll and employee benefit costs; and
- increased income tax expense related to higher taxable income.

Dividends paid on our common stock were $1.44 a share in 2007, compared to $1.39 a share in 2006 and $1.32 a share in 2005. The current indicated annual dividend rate is $1.50 per share.

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America (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 or judgments involve regulatory cost recovery, revenue recognition, derivative instruments, pension assumptions, income taxes and environmental contingencies. Management has discussed the estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Our critical accounting policies and estimates are described below.

Within the context of our critical accounting policies and estimates, management is not currently aware of any reasonably likely events or circumstances that would result in materially different amounts being reported.

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, certain accounting principles, primarily Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, 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. SFAS No. 71 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 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.

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The conditions we must satisfy to adopt the accounting policies and practices of SFAS No. 71, 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.

We continue to apply SFAS No. 71 in accounting for our regulated utility operations. Future regulatory changes or changes in the competitive environment could require us to discontinue the application of SFAS No. 71 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 regulatory and competitive conditions, we believe that it is reasonable to expect continued application of SFAS No. 71 for our regulated activities, and that all of our regulatory assets and liabilities at December 31, 2007 and 2006 are recoverable or refundable through future customer rates. See Note 1, Industry Regulation.

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 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, 2007 and 2006 were $78.0 million and $87.5 million, respectively. The decrease in accrued unbilled revenues at year-end 2007 was primarily due to lower gas prices included in customer rates. If the estimated percentage of unbilled volume at December 31, 2007 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 $3.0 million, $1.5 million and $0.9 million, respectively.

Utility revenues may also include the recognition of a regulatory adjustment for income taxes paid (see Results of Operations Regulatory Matters Regulatory Adjustment for Income Taxes Paid, below). 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 the tax year.

Non-utility revenues, derived primarily from our gas storage business segment, are recognized upon delivery of the service to customers. Revenues from our optimization partner are recognized over the life of the optimization contract for the guaranteed amount, or are recognized as they are earned for amounts above the guaranteed value.

Accounting for Derivative Instruments and Hedging Activities

Our Financial Derivatives Policy and Gas Acquisition Policy set forth guidelines for using financial derivative instruments to support prudent risk management strategies within designated

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parameters. 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 qualify as derivative instruments 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 SFAS No. 71 (see Note 1, Industry Regulation) and no gain or loss is recognized in current income. The gain or loss from the fair value of a derivative instrument that is 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 gains and losses is made in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 138 and SFAS No. 149, collectively referred to as SFAS No. 133 (see Note 1, Derivatives and Industry Regulation). Our estimate of fair value is determined from period-to-period based on an internal discounted cash flow model for swap contracts and on a Black-Scholes model for option contracts. The 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 at December 31, 2007 and 2006, see Note 11.

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, with 67 percent of unrealized gains and losses recorded to a regulatory asset or liability account. The remaining 33 percent is recognized in current income for contracts not qualifying for hedge accounting or is recognized in Other Comprehensive Income for contracts qualifying for hedge accounting. An interest rate swap qualifies for hedge accounting under SFAS No. 133. During the fourth quarter of 2006, we entered into a number of financial derivatives related to commodity purchases by the utility after our PGA filing. The $2.9 million loss was reversed during 2007 in the cost of gas when the derivative contract settled.

Derivative contracts are subjected to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2007, all of our derivatives were effective economic hedges and either qualified or were expected to qualify for regulatory deferral, or hedge accounting treatment. We utilize the hypothetical derivative method under SFAS No. 133 to determine the hedge effectiveness of our interest rate swap and the dollar offset method under SFAS No. 133 for all other derivative contracts. The effectiveness test applied to financial derivatives is dependent on the type of derivative and its use.

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

Thousands	2007	2006	2005
Net gain (loss) on commodity-price swaps utility	$ (41,954)	$ (18,849)	$ 90,205
Net loss on commodity-price options utility	(662)	(1,160)	(1,315)
Subtotal on commodity utility	(42,616)	(20,009)	88,890
Net gain on foreign currency forward purchases utility	662	355	532
Total realized net gain (loss)	$ (41,954)	$ (19,654)	$ 89,422

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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. Unrealized gains and losses resulting from mark-to-market valuations are generally not recognized in current income or other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, which are offset by a corresponding balance in non-trading derivative assets or liabilities (see Note 11).

Accounting for Pensions

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 employee postretirement 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, the Retirement Plan for Non-Bargaining Unit Employees and the Welfare Benefits Plan for Non-Bargaining Unit Employees were closed to anyone hired or rehired after December 31, 2006. Instead, newly hired or rehired non-bargaining unit employees are provided an enhanced Retirement K Savings Plan benefit. Benefits provided to bargaining unit employees under the Retirement Plan for Bargaining Unit Employees are not affected by these changes.

Net periodic pension costs (pension costs) and projected benefit obligations (benefit obligations) are determined in accordance with SFAS No. 87, Employers Accounting for Pensions, using a number of key assumptions including discount rates, rate of compensation increases, retirement ages, mortality rates and the expected long-term return on plan assets (see Note 7). These key assumptions have a significant impact on the amounts reported. Pension 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. The market-related valuation reflects differences between expected returns and actual investment returns, which are recognized over a three-year period from the year in which they occur, thereby reducing year-to-year volatility in pension costs.

Effective December 31, 2006, the funded status of our pension plans was required to be recognized in accordance with SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Benefit Plans (SFAS No. 158). SFAS No. 158 requires balance sheet recognition of the overfunded or underfunded status of pension 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 pension costs relating to certain NW Natural pension plans are recovered in utility rates based on SFAS No. 87, and as such we received regulatory approval from the OPUC pursuant to SFAS No. 71, to record a regulatory asset or regulatory liability, rather than include AOCI in common equity, for the funded status of those plans (see Regulatory Accounting , above, and Note 1, Industry Regulation).

A number of factors are considered in developing pension assumptions, including an evaluation of relevant discount rates, expected long-term investment returns, plan asset allocations, expected changes in salaries, wages and retirement benefits, analyses of current market conditions and input from actuaries and other consultants. For the December 31, 2007 measurement date, we:

updated the pension discount rate assumptions from a range of 6.00 percent to 6.05 percent to a range of 6.75 percent to 6.87 percent. The new rate assumptions were determined for

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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 or Aa3 or higher by Moody s Investors Service;

confirmed the expected rate of future compensation increases between 4.00 and 5.00 percent;

confirmed the expected long-term return on plan assets at 8.25 percent; and

reviewed and updated other key assumptions as needed.

Changes in valuation assumptions impact our projected benefit obligations. The projected benefit obligations at December 31, 2007 decreased $23.9 million due to an increase in the discount rate assumptions and increased by $3.4 million due to an increase in the benefit payments for certain retirees.

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 rate of return assumption, 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. The actual annualized returns on plan assets, net of management fees, for the past one-year, five-year and 10-year periods ended December 31, 2007 were 8.98 percent, 14.17 percent and 8.92 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 pension costs and benefit obligations to future changes in certain actuarial assumptions:

Thousands, except percent	Change in Assumption	Impact on 2007 Pension Costs	Impact on Benefit Obligations at Dec. 31, 2007
Discount rate	(0.25%)	$ 569	$ 8,682
Expected long-term return on plan assets	(0.25%)	$ 560	N/A

The impact of a change in pension 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.

Accounting for Income Taxes

We account for income taxes in accordance with SFAS 109 and Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), which require that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. SFAS 109 and FIN 48 also require that deferred tax assets be reduced by a valuation if it is more likely than not that some portion or all of the deferred tax asset will not be realized. We adopted the provisions of FIN 48 on January 1, 2007. At the date of adoption and as of December 31, 2007, we did not have a liability for unrecognized tax benefits as all positions taken are considered highly certain. Our net long-term deferred tax liability totaled $203.1 million at December 31, 2007. This liability is estimated based on the expected future tax consequences of items recognized in the financial statements. After application of the federal statutory

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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 other 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, 2007, we did not have a valuation allowance due to our expectation that all of these assets will be realized.

SFAS No. 109 also requires the recognition of additional 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, 2007 and 2006, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $68.6 million and $67.1 million, respectively, and recorded an offsetting deferred tax liability for the same amounts (see Note 1, Income Tax Expense). We believe that it is reasonable to expect recovery of these regulatory assets through future customer rates. However, future regulatory changes could require the write-off of all or a portion of these regulatory assets should they no longer be probable of recovery in future rates (see Regulatory Accounting, above, and Notes 1 and 8).

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 SFAS No. 5, Accounting 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 estimated that the total future expenditures for environmental investigation, monitoring and remediation are $38.3 million as of December 31, 2007. 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.

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 12).

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. In 2007, 93 percent of our utility gas deliveries and 91 percent of our 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 pace of continued customer growth in the residential and commercial markets and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, operating and maintenance costs and investments made in utility plant.

General Rate Cases

Our most recent general rate increase in Oregon authorized rates to customers based on a return on shareholders equity (ROE) of 10.2 percent and was effective September 1, 2003. We retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points, subject to adjustment up or down each year based on movements in long-term interest rates. Our most recent general rate case in Washington authorized a revenue increase of $3.5 million per year but did not specifically authorize an ROE and was effective July 1, 2004. Our plans are to file a general rate case in Washington in 2008.

The current maximum cost-based rates for our interstate gas storage services were approved by FERC in 2005. These rates are designed to reflect updated costs related to development of the Mist gas storage facility from 2001 through 2005. Pursuant to this approval, we were required to file either a petition for rate approval or a cost and revenue study with FERC by January 18, 2008. We requested and received an extension to enable us to file a cost and revenue study based on our actual 2007 results. We expect to file the study by March 31, 2008.

Oregon Rate Case Moratorium. 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, or expansion of our automated meter reading program if an existing joint meter reading program with a local electric utility ends. This agreement does not impact our ability to file annual rate adjustments to reflect changes in gas purchase costs under our PGA mechanism and to collect, or refund, prior year s gas cost deferrals.

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Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA tariff mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including contractual arrangements to hedge the purchase price with financial derivatives (see Comparison of Gas Distribution Operations Cost of Gas Sold, below), 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. Under the current PGA mechanisms, we collect an amount for purchased gas costs based on contract prices and market estimates included in rates. If the actual purchased gas costs differ from the estimated amounts included in rates, then we are required to defer that difference and pass it on to customers as an adjustment to future rates. As part of an incentive mechanism in Oregon, only 67 percent of the difference is deferred such that the impact on current earnings is either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower cost of gas sold. In Washington, the PGA deferral requires 100 percent of all prudently incurred gas costs to be passed through in customer rates.

In October 2007, the OPUC and the WUTC approved rate decreases effective on November 1, 2007 under our PGA mechanism. The rate reduction lowered average monthly bills of Oregon residential customers by 8.0 percent and those of Washington residential customers by 9.8 percent. The PGA mechanism reflects the January 2007 rates approved by FERC for interstate pipeline suppliers. Pursuant to the PGA tariffs, approved rate changes effective November 1, 2006 increased average monthly bills of Oregon residential sales customers by 3.5 percent and those of Washington residential sales customers by 2.6 percent. In 2005, the OPUC approved a PGA rate increase averaging 15.2 percent for Oregon residential sales customers, and the WUTC approved a rate increase averaging 12.0 percent for Washington residential sales customers, both effective October 1, 2005.

The OPUC is currently conducting a formal review of the PGA process used by natural gas utilities in Oregon covering gas portfolio requirements, incentive sharing levels and filing requirements, among other items. The review is expected to be completed in 2008. Implementation of any changes to the PGA mechanism is likely to become effective with the 2008 PGA filing.

Conservation Tariff. In October 2002, the OPUC authorized the implementation of a conservation tariff, which is a rate mechanism designed to adjust margin to compensate the utility 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 earnings and the quantity of energy 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 utility revenues.

The Oregon conservation tariff includes two components: (1) a price elasticity adjustment, which adjusts rates annually for expected increases or decreases in 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 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 for current customer growth. See Part II, Item 7., Results of Operations Comparison of Gas Distribution Operations, below.

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 has 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, decreasing rates when the weather is colder than average and increasing rates when it is warmer than average. The mechanism is applied to our residential and commercial customers bills between December 1 and May 15 for 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 Comparison of Gas Distribution Operations, below). We do not have a weather normalization mechanism approved for our Washington customers, which accounts for about 10 percent of our utility revenues.

Excess Earnings Test. We are subject to an excess earnings test requirement in which we retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points. Revenues equivalent to 33 percent of any earnings above the threshold are required to be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year based on movements in long-term interest rates. In 2007 and 2006, the threshold after adjustment was 13.40 percent and 13.44 percent, respectively. No amounts were required to be refunded to customers as a result of the 2006 or 2005 earnings test, and we do not expect that any amounts will be required to be refunded to customers as a result of the 2007 earnings test, which will be reviewed by the OPUC during the second quarter of 2008. The OPUC s annual formal review process to test for excess earnings ensures that we are allowed to pass through 100 percent of prudently incurred gas costs into rates. In Washington, we are not subject to an annual excess earnings test, and 100 percent of all prudently incurred gas costs are passed through into customer rates in the annual PGA.

Industrial Tariffs. In August 2006, the OPUC and WUTC approved tariff changes to the service options for our major industrial accounts. The changes set out additional parameters that give us more certainty in the level of gas supplies we will need to acquire to serve this customer group. The parameters include an annual election period, special pricing provisions for out-of-cycle changes and a requirement that customers on our annual weighted average cost of gas tariff complete the term of their service election.

Pipeline Integrity Cost Recovery. In July 2004, the OPUC approved the accounting treatment and full recovery for the cost of our 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 (see Financial Condition Cash Flows Investing Activities, below). We classify our costs as either capital expenditures or regulatory assets, accumulate the costs over each 12 months ending September 30, and recover the

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costs, subject to audit, through rate changes effective with the annual PGA. The accounting and rate treatment for these costs extends through September 30, 2008 and may be reviewed for potential extension after that date. We do not have any special accounting or rate treatment for pipeline integrity costs incurred in the state of Washington.

Smart Energy Program. Effective September 1, 2007, the OPUC approved our Smart Energy program. Smart Energy allows residential and commercial customers to offset greenhouse gases produced from their natural gas use. The Smart Energy rate is designed to neutralize the impact of greenhouse gases, such as carbon dioxide and methane, by funding projects that prevent, reduce or capture emissions released into the atmosphere. Offset funds collected from customers participating in the program will be forwarded to The Climate Trust and these funds will specifically target the reduction of methane emissions from farm operations.

Regulatory Adjustment for Income Taxes Paid

During 2005, the Oregon legislature passed legislation, effective January 1, 2006, intended to ensure that utilities do not collect in rates more income taxes than they actually pay to taxing authorities. The OPUC adopted permanent rules to implement this legislation in September 2006, which were subsequently amended, with the revised rules approved in September 2007. The OPUC rules require us to identify the amount of income taxes paid, as well as the amount of taxes authorized to be collected in rates during the tax year. If amounts paid and amounts collected differ by more than $100,000, the OPUC is required to direct the utility to implement a rate schedule with an automatic adjustment clause to refund or surcharge for the difference. For more information regarding this requirement, see Comparison of Gas Distribution Operations Regulatory Adjustment for Income Taxes Paid, below.

In January 2008, the Internal Revenue Service (IRS) ruled on our request for a Private Letter Ruling on the issue of whether this state law complies with the provisions of federal tax law, including the normalization requirements of the Internal Revenue Code. The IRS ruling indicated that, as presented to them, the Oregon law does not violate the normalization requirements of federal tax law.

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Comparison of Gas Distribution Operations

The following table summarizes the composition of gas utility volumes and revenues for the years ended December 31, 2007, 2006 and 2005:

Thousands except degree day and customer data	2007	2006	2005	Favorable/(Unfavorable) 2007 vs. 2006	Favorable/(Unfavorable) 2006 vs. 2005
Utility volumes - therms:					
Residential sales	398,960	382,665	371,538	16,295	11,127
Commercial sales	249,659	242,683	233,987	6,976	8,696
Industrial - firm sales	52,340	66,971	74,880	(14,631)	(7,909)
Industrial - firm transportation	161,790	150,153	135,807	11,637	14,346
Industrial - interruptible sales	89,128	112,736	149,106	(23,608)	(36,370)
Industrial - interruptible transportation	263,092	237,441	192,249	25,651	45,192
Total utility volumes sold and delivered	1,214,969	1,192,649	1,157,567	22,320	35,082
Utility operating revenues - dollars:					
Residential sales	$ 555,312	$ 536,468	$ 471,502	$ 18,844	$ 64,966
Commercial sales	298,800	290,666	250,287	8,134	40,379
Industrial - firm sales	54,567	66,986	64,507	(12,419)	2,479
Industrial - firm transportation	5,927	4,901	4,087	1,026	814
Industrial - interruptible sales	74,876	93,107	100,740	(18,231)	(7,633)
Industrial - interruptible transportation	8,264	7,899	6,668	365	1,231
Regulatory adjustment for income taxes paid [(1)]	5,996			5,996	
Other revenues	12,228	161	2,862	12,067	(2,701)
Total utility operating revenues	1,015,970	1,000,188	900,653	15,782	99,535
Cost of gas sold	639,094	648,081	563,772	8,987	(84,309)
Revenue taxes	25,001	24,840	21,633	(161)	(3,207)
Utility net operating revenues (utility margin)	$ 351,875	$ 327,267	$ 315,248	$ 24,608	$ 12,019
Utility margin: [(2)]					
Residential sales	$ 213,698	$ 204,951	$ 195,098	$ 8,747	$ 9,853
Commercial sales	85,960	83,334	78,919	2,626	4,415
Industrial - sales and transportation	31,333	32,383	31,632	(1,050)	751
Miscellaneous revenues	4,966	4,333	4,990	633	(657)
Other margin adjustments	11,906	2,610	2,950	9,296	(340)
Margin before regulatory adjustments	347,863	327,611	313,589	20,252	14,022
Weather normalization mechanism	(2,496)	2,282	(1,308)	(4,778)	3,590
Decoupling mechanism	512	(2,626)	2,967	3,138	(5,593)
Regulatory adjustment for income taxes paid [(1)]	5,996			5,996	
Utility margin	$ 351,875	$ 327,267	$ 315,248	$ 24,608	$ 12,019
Customers - end of period:					
Residential customers	589,676	575,116	556,667	14,560	18,449
Commercial customers	61,397	60,523	59,543	874	980
Industrial customers	939	945	953	(6)	(8)

Total number of customers - end of period	652,012	636,584	617,163	15,428	19,421
Actual degree days	4,374	4,089	4,178		
Percent colder (warmer) than average [3]	3%	(4%)	(2%)		

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(1) Regulatory adjustment for income taxes paid is the result of the implementation of the utility regulation as described above under Regulatory Matters Regulatory Adjustment for Income Taxes Paid, and described below under Regulatory Adjustment for Income Taxes Paid.

(2) Amounts reported as margin for each category of customers is 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.

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 contributes to changes in margin based on changes in residential and commercial customer consumption, and we have a weather normalization mechanism that adjusts customer bills up or down contributing to changes in margin based on above- or below-average temperatures during the winter heating season (see Results of Operations Regulatory Developments Rate Mechanisms, above). Both mechanisms are designed to reduce the volatility of our utility earnings.

2007 compared to 2006:

Total utility margin increased $24.6 million or 8 percent in 2007 compared to 2006 with residential and commercial customers contributing an additional $11.4 million to margin in 2007, not including the effects of the weather normalization and decoupling mechanisms. The $1.0 million decrease in margin from industrial customers in 2007 was partially offset by a decrease in revenue adjustments from regulatory deferrals and amortizations and miscellaneous fees. The weather normalization and decoupling mechanisms decreased margin by a net $1.6 million in 2007 compared to 2006, primarily reflecting colder weather, partially offset by an increase in decoupling that reflects higher than expected consumption. Total utility volumes sold and delivered in 2007 were about the same as last year. An increase in regulatory sharing of gas cost savings of $4.0 million and a regulatory adjustment related to income taxes paid of $6.0 million also contributed to the increase in margin (see Regulatory Adjustment for Income Taxes Paid, and Cost of Gas Sold, below).

Volume increases in 2007 were due mainly to residential and commercial customer growth, which reflects a net increase of 15,428 customers during 2007, or an annual growth rate of 2.4 percent. Our growth rate has slowed but remains well above the national average for local gas distribution companies. Recent economic conditions have slowed the level of new construction in our service territory.

Our weather normalization mechanism reduced margin by $2.5 million for the year ended December 31, 2007 based on weather that was 3 percent colder than average, compared to an increase of $2.3 million in added margin for the year ended December 31, 2006 based on weather that was 4 percent warmer than average. The weather normalization mechanism is designed to balance our margins when weather deviates from average.

The decoupling mechanism increased margin by $0.5 million in 2007, after adjusting for price elasticity in the annual Oregon PGA filing, compared to a margin decrease of $2.6 million in 2006. Decoupling is designed to adjust to our margin to reflect changes in customer usage due to customer conservation efforts.

2006 compared to 2005:

Total utility margin increased $12.0 million or 4 percent in 2006 compared to 2005 with residential and commercial customers contributing an additional $12.3 million to margin in 2006,

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including the effect of the weather normalization and decoupling mechanisms. The $0.8 million increase in margin from industrial customers in 2006 was offset by a decrease in revenue adjustments from regulatory deferrals and amortizations and miscellaneous fees. The weather normalization and decoupling mechanisms decreased margin by a net $2.0 million in 2006 compared to 2005, primarily reflecting lower than expected consumption decline due to customer conservation efforts.

Our customer base grew in 2006, with a net increase of 19,421 customers. The growth rate for 2006 was 3.1 percent, compared to 3.4 percent in 2005. The slower growth rate in 2006 was primarily due to a smaller increase in residential customers reflecting a modest slowdown in new construction.

In 2006, weather was 2 percent warmer than in 2005. The weather normalization mechanism added $2.3 million to margin for the year ended December 31, 2006 based on weather that was 4 percent warmer than average, and reduced margin by $1.3 million in 2005 based on weather that was 2 percent warmer than average. Generally, we would have expected the weather normalization mechanism in 2005 to recover lost margin when temperatures were warmer than average, but that year we lost heating volumes and corresponding margin revenues in the latter part of May when temperatures were significantly warmer than average because those volume and margin losses were not entirely covered by the weather normalization mechanism, which ends on May 15 each year.

The decoupling mechanism decreased margin by $2.6 million in 2006, after adjusting for price elasticity in the annual Oregon PGA filing, compared to a contribution of $3.0 million in 2005.

Residential and Commercial Sales

Residential and commercial sales markets are impacted by 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. Beginning in 2006, this mechanism became effective for the period from December 1 through May 15 of each heating season. Approximately 10 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 our customers, so that we do not have an incentive to discourage customers from conserving energy. 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, these mechanisms do not fully insulate the utility from earnings volatility due to weather and conservation. See the above tables under Comparison of Gas Distribution Operations for the adjustments to utility margin revenues from the weather normalization and decoupling mechanisms.

The primary factors that impact results of operations in the residential and commercial markets are seasonal weather patterns, competition from other energy sources and economic conditions in our service territory.

2007 compared to 2006:

- operating revenues increased 3 percent, primarily due to a 4 percent increase in volumes;
- volumes were 4 percent higher, primarily reflecting 2.4 percent customer growth and 7 percent colder weather; and

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margin before regulatory adjustments for weather normalization, decoupling and income taxes paid was 4 percent higher, reflecting increased volumes from customer growth and higher gas cost savings from our PGA incentive sharing mechanism in Oregon (see Cost of Gas Sold, below).

2006 compared to 2005:

- volumes sold were 3 percent higher, primarily reflecting 3.1 percent customer growth in the residential and commercial sector and improved economic conditions, partially offset by 2 percent warmer weather;
- operating revenues were 15 percent higher, primarily due to a 3 percent increase in volumes and an 11 percent increase in the average rate per therm due to recent PGA rate increases, effective October 1, 2005 and November 1, 2006; and
- margin was 5 percent higher, reflecting customer growth and higher gas cost savings from our PGA incentive sharing mechanism in Oregon (see Cost of Gas Sold, below).

Industrial Sales and Transportation

The primary factors that impact results of operations in the industrial sales and transportation markets are commodity costs, competition and economic conditions in our service territory.

2007 compared to 2006:

- operating revenue decreased $29.3 million, or 17 percent, due to customers transferring from sales service to transportation service where cost of gas is not a component in operating revenues;
- volumes delivered to industrial customers decreased 1.0 million therms, or less than 1 percent, reflecting a reduction in sales volumes of 38.2 million therms offset by an increase in transportation volumes of 37.3 million therms; and
- margin decreased 3 percent, reflecting higher volumes under lower margin special contracts.

2006 compared to 2005:

- volumes delivered to industrial customers increased 15.3 million therms, or 2.8 percent, with the increase primarily in lower margin interruptible schedules;
- operating revenue decreased $3.1 million, or 1.8 percent, due to customers transferring from sales service to transportation service where cost of gas is not a component in operating revenues; and
- margin increased 2 percent, reflecting increased volumes.

Several large industrial customers transferred from sales service back to transportation service in 2006. High natural gas prices result, from time to time, in a number of our large industrial customers switching from 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 to serve those customers.

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Regulatory Adjustment for Income Taxes Paid

Based upon the revised rules issued by the OPUC in September 2007, we filed our 2007 Tax Report for the 2006 tax year on October 15, 2007. For the 2006 tax year, we estimated the utility was entitled to recover $1.7 million through a surcharge to our Oregon utility customers based on taxes paid that were greater than taxes collected, which was primarily driven by gains from gas cost savings from the PGA incentive sharing mechanism in 2006. The increase in Oregon revenues for this surcharge is expected to go into effect June 1, 2008 and would be recovered in a one-time adjustment to customers. For the 2007 tax year, we estimate the utility will again be entitled to a surcharge for taxes paid in excess of taxes collected in rates, largely driven by gains from gas cost savings from the PGA incentive sharing mechanism in 2007. For 2007, we recognized an estimated surcharge of $4.3 million. The combined 2006 and 2007 surcharge estimate of $6.0 million was recognized in 2007 and is included in Gross operating revenues. Deferred income tax expense of $2.4 million was also recognized in 2007 related to the 2006 and 2007 estimated surcharges, resulting in a net contribution to earnings of $3.6 million (see Regulatory Matters Regulatory Adjustment for Income Taxes Paid, above).

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 $12.2 million in 2007, compared to $0.2 million in 2006 and $2.9 million in 2005.

2007 compared to 2006:

Other revenues in 2007 were $12.1 million higher than in 2006 primarily due to a $3.1 million increase in deferrals under the decoupling mechanism (see Results of Operations Regulatory Matters Rate Mechanisms, above), a $6.1 million decrease in amortization expense related to the decoupling deferrals from prior periods, a $1.7 million increase in interstate gas storage credits to customers reflecting higher regulatory sharing of net income from storage operations and a decrease of $1.3 million in amortization expense related to demand side management deferrals.

2006 compared to 2005:

Other revenues in 2006 were $2.7 million lower than in 2005 primarily due to a $5.6 million decrease in deferrals under the decoupling mechanism (see Results of Operations Regulatory Matters Rate Mechanisms, above) and a $1.5 million increase in amortization of the decoupling deferrals from prior periods, partially offset by an increase of $1.3 million in interstate gas storage credits to customers reflecting increased net income from storage operations, a decrease of $1.7 million in amortization expense for the South Mist Pipeline Extension and a decrease of $1.0 million in the deferral for the Oregon income tax kicker refund.

Cost of Gas Sold

Natural gas commodity prices had risen significantly in recent years, but the cost of gas decreased slightly in 2007. The effects of higher commodity prices and price volatility on core utility customers are mitigated, in part, through our use of underground storage facilities, fixed-price commodity hedge contracts and short term sales of excess gas supply and transportation capacity to off-system customers in periods when core utility customers do not require the full amount of contract gas supplies or firm pipeline capacity.

The total cost of gas sold was $639.1 million in 2007, a decrease of $9.0 million or 1 percent compared to 2006, and cost of gas sold in 2006 was $648.1 million, an increase of $84.3 million or 15 percent higher than 2005. The cost per therm of gas sold includes current gas purchases, gas drawn from storage inventory, gains or losses from commodity hedges, margin from off-system gas sales, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

Under the PGA tariff in Oregon, our net income is affected within defined limits by changes in purchased gas costs (see Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, above). In each of the last three years, our actual gas costs were lower than the gas costs embedded in rates, with the effect being that our share of the cost savings increased margin by $12.1 million, $8.1 million and $4.2 million for 2007, 2006 and 2005, respectively.

We use natural gas derivatives, primarily fixed-price commodity swaps, under the terms of our Financial Derivatives Policy, to help manage our exposure to floating price gas purchase contracts (see Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, above, and Note 11). We realized net losses of $42.0 million and $20.0 million from our financial hedges in 2007 and 2006, respectively, compared to a gain of $88.9 million in 2005. Gains and losses from the financial hedging of utility gas purchases generally are included in cost of gas, but generally do not impact net income because the hedges are factored into our PGA deferrals and annual rate changes. To the extent that any utility gas hedge is entered into after the annual PGA filing, then the gains and losses are subject to our PGA incentive sharing mechanism with 67 percent deferred and 33 percent recorded to current income.

Business Segments Other than Local Gas Distribution

Gas Storage

We earned $8.7 million in net income from our non-utility gas storage business segment in 2007, after regulatory sharing and income taxes, equivalent to 32 cents a share, compared to $6.0 million or 21 cents a share in 2006 and $4.6 million or 17 cents a share in 2005 (see Note 2). Earnings from this business segment were higher in 2007 primarily because of increased revenues from additional contract storage and higher margins from our contract with an independent energy marketing company that optimizes the value of our utility assets.

In Oregon, we retain 80 percent of the pre-tax income from gas storage as well as from third party optimization revenues when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income from such storage and optimization when the capacity costs have been included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for crediting to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from storage services and third party optimization.

Other

The other business segment primarily consists of a wholly-owned subsidiary, Financial Corporation, as well as various other non-utility investments, including an investment in an aircraft that is leased to a U.S. airline, our equity investment in a proposed natural gas transmission pipeline project (Palomar Pipeline), and our wholly-owned subsidiary, Gill Ranch (see Note 9). Our net investment

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balance in Financial Corporation at December 31, 2007 and 2006 was $1.4 million and $2.6 million, respectively. The decrease primarily reflects the sale in October 2007 of investments in alternative energy projects for $2.1 million plus our portion of the investments retained cash, resulting in an after-tax gain of $0.9 million. Our net investment balance in the aircraft lease at December 31, 2007 and 2006 was $3.2 million and $5.3 million, respectively, with the decrease primarily due to the receipt in March 2007 of the final payment due under the terms of the original 20 year lease agreement. Our equity investment balance in the proposed natural gas pipeline project with GTN was $6.0 million at December 31, 2007 and a negligible amount at December 31, 2006 (see Strategic Opportunities Pipeline Diversity, above).

Net income from our other business segment was $0.8 million for each of 2007, 2006 and 2005. In 2007, we recognized net income of $1.2 million from Financial Corporation, primarily related to the sale of limited partnership interests in two wind power electric generation projects in California. These sales generated an after-tax gain of $0.9 million. This was offset in part by the net loss we recognized related to the Gill Ranch investment of $0.3 million.

Subsidiaries

Financial Corporation

Operating results in 2007 were net income of $1.2 million, compared to $0.2 million in 2006 and $0.3 million in 2005. The increase is primarily due to the gain from the sale of Financial Corporation s limited partnership interests in two wind power electric generation projects in California in October 2007.

Gill Ranch

In September 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 Gill Ranch as a subsidiary of NW Natural. See Strategic Opportunities Gas Storage Development, above.

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses increased by $5.9 million in 2007, or 5 percent, compared to 2006 which in part reflects certain strategic initiatives which increased operations and maintenance expense. These initiatives included additional training expenses ($1.2 million), promotional and safety campaigns ($1.2 million) and maintenance projects ($1.9 million). Absent these strategic initiatives, operations and maintenance would have increased 1 percent. Operations and maintenance expense increased $1.3 million in 2006, or 1 percent, compared to 2005. The following summarizes the major factors that contributed to changes in operations and maintenance expense:

2007 compared to 2006:

- a $3.8 million increase in employee compensation and benefit expense, primarily due to bonuses related to improved financial and operating results on annual and long-term incentive plan performance goals;
- a $1.9 million increase in costs for maintenance projects and geo-hazard repairs;

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- a $0.9 million increase in training, maintenance and telecommunication expenses related to the implementation of the first phase of a new integrated information system; and
- a $0.3 million increase in start up expenses for the Smart Energy program.

Partially offsetting the above increases was:

- a $1.5 million decrease in severance expenses.

2006 compared to 2005:

- a $2.0 million increase in payroll expense, primarily due to bonuses related to improved results on annual and long-term incentive plan performance goals;
- a $1.1 million increase in severance expenses related to the 2006 severance incentive plan; and
- a $0.8 million increase in stock option expense due to the required adoption of SFAS No. 123R related to stock-based compensation expense.

Partially offsetting the above increases were:

- a $1.2 million decrease in system damages and damage claims written-off; and
- a $2.3 million reduction in charges related to a settlement with a group of industrial customers in 2005.

General Taxes

General taxes, which are principally comprised of property and payroll taxes, increased $0.9 million, or 4 percent, in 2007 compared to 2006, and increased $1.2 million, or 5 percent, in 2006 compared to 2005. The major factors that contributed to changes in general taxes are:

2007 compared to 2006:

- a $0.4 million increase in property taxes related to a 3 percent increase in net utility plant;
- a $0.3 million increase in regulatory fees based on higher gross operating revenue; and
- a $0.2 million increase in other taxes due to an increase in the annual fee to the Oregon Department of Energy.

2006 compared to 2005:

- a $0.7 million increase in property taxes;
- a $0.5 million increase in regulatory fees based on higher revenue; and
- a $0.1 million decrease in payroll taxes.

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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	2007	2006	2005
Plant and property:			
Utility plant:			
Depreciable	$ 2,013,191	$ 1,925,837	$ 1,839,206
Non-depreciable, including construction work in progress	38,970	37,661	36,238
	2,052,161	1,963,498	1,875,444
Non-utility property:			
Depreciable	56,444	36,952	36,920
Non-depreciable, including construction work in progress	10,705	5,700	3,916
	67,149	42,652	40,836
Total plant and property	$ 2,119,310	$ 2,006,150	$ 1,916,280
Depreciation and amortization:			
Utility plant	$ 67,410	$ 63,552	$ 60,935
Non-utility property	933	883	710
Total depreciation and amortization expense	$ 68,343	$ 64,435	$ 61,645
Average depreciation rate - utility	3.4%	3.4%	3.4%
Average depreciation rate - non-utility	2.1%	2.5%	2.6%

Total depreciation and amortization expense increased by $3.9 million, or 6 percent, in 2007 and by $2.8 million, or 5 percent, in 2006. The increased expense for both years is 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). In 2006, we completed a depreciation study on all company plant and property, which generally indicates that depreciation rates overall would be reduced if we maintain the existing average service life depreciation method. We applied for the adoption of new depreciation rates using the average service life method. However, if the OPUC or WUTC were to require us to adopt a different depreciation method such as the equal life group method, then depreciation rates could increase. Utility depreciation rates and methods are subject to review and approval by the OPUC and WUTC, and new rates will not be placed into service until depreciation rate proceedings are approved. We submitted the updated depreciation study for regulatory approval in 2007 and will implement the new rates upon approval. We do not anticipate that adoption of these new rates will have a material impact on our financial condition or results of operations.

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Other Income and Expense Net

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

Thousands	2007	2006	2005
Gains from company-owned life insurance	$ 1,939	$ 2,609	$ 1,856
Interest income	537	363	403
Other non-operating expenses	(2,789)	(852)	(1,393)
Net interest on deferred regulatory accounts	84	(177)	282
Gain on sale of equity investments	1,544	-	-
Earnings from equity investments of Financial Corporation	130	191	57
Total other income	$ 1,445	$ 2,134	$ 1,205

Other income and expense net declined by $0.7 million in 2007 over 2006. The decline was primarily due to a decrease of $0.7 million from company-owned life insurance, reflecting lower policy benefits realized during 2007, and a net increase of $1.9 million in other non-operating expenses, reflecting expenses for business development and other strategic initiatives. These negative changes were partially offset by an increase in earnings from equity investments of Financial Corporation of $1.5 million, reflecting the gain on sale on its limited partnership interests in two wind power electric generation projects, and an increase of $0.3 million in net interest charges on deferred regulatory accounts, reflecting lower net credit balances outstanding in these accounts.

Other income and expense net improved by $0.9 million in 2006 over 2005. The increase was primarily due to higher gains of $0.8 million from company-owned life insurance, reflecting higher policy benefits realized during 2006, and a net decrease of $0.5 million in other non-operating expenses, reflecting cost reduction initiatives. These positive changes were partially offset by a $0.5 million increase in net interest charges on deferred regulatory accounts, reflecting higher net credit balances outstanding in these accounts.

Interest Charges Net of Amounts Capitalized

Interest charges net of amounts capitalized in 2007 was $1.4 million, or 4 percent, lower than in 2006, reflecting lower balances on long-term debt outstanding due to the redemption of $20 million in March 2007 and $9.5 million in May 2007. In 2006, interest charges net of amounts capitalized was $2.0 million, or 5 percent, higher than in 2005, reflecting higher interest rates on short-term debt balances and slightly higher average balances of long-term debt outstanding during the period due to the issuance of $50 million in June 2005 and $25 million in December 2006. The increase in an allowance for funds used during construction (AFUDC) in 2006 reflects higher construction work in progress balances. The average interest crediting rate for AFUDC, comprised of short-term and long-term borrowing rates, as appropriate, was 5.4 percent in 2007, 4.7 percent in 2006 and 3.1 percent in 2005.

Income Tax Expense

The increase in income tax expense of $7.8 million or 22% in 2007, compared to 2006 was primarily due to higher consolidated earnings and a slightly higher effective tax rate of 37.2% in 2007 compared to 36.4% in 2006. The increase in our effective tax rate was primarily a result of a lower non-taxable gain on company-owned life insurance. We expect our effective tax rate in 2008 to remain consistent with our 2007 rate. Income tax expense increased by $3.5 million in 2006, as compared to total income tax expense of $32.7 million in 2005, and the effective tax rate increased 0.4 percent from an effective tax rate of 36.0 percent in 2005. For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective rate, see Note 1.

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 3, 5 and 6). Our consolidated capital structure was as follows:

December 31,	2007	2006
Common stock equity	47.4%	48.1%
Long-term debt	40.8%	41.5%
Short-term debt, including current maturities of long-term debt	11.8%	10.4%
Total	100.0%	100.0%

Achieving the target capital structure and maintaining sufficient liquidity are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs.

Liquidity and Capital Resources

At December 31, 2007, we had $6.1 million in cash and cash equivalents compared to $5.8 million at December 31, 2006. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by committed lines of credit. We have available a committed bank facility totaling $250 million through May 31, 2012 (see Credit Agreement, below, and Note 6). Short-term debt balances typically are reduced toward the end of the winter heating season as a significant amount of our current assets, primarily accounts receivable and gas inventories, are converted into cash.

Capital expenditures primarily relate to utility construction resulting from customer growth and system improvements (see Cash Flows Investing Activities, below). Certain contractual commitments under capital leases, operating leases, gas supply purchase contracts and other contracts require an adequate source of funding. These capital and contractual expenditures 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.

To provide long-term financing, we periodically issue and sell secured or unsecured debt, preferred stock or common stock. In June 2005 and December 2006, we issued $50 million and $25 million of secured medium-term notes, respectively. At December 31, 2007, we had $85 million available for future issuance of debt or equity securities under a universal shelf registration, which was approved by the OPUC (see Financing Activities, below). On January 8, 2008, we filed a new universal shelf registration for an unspecified amount of securities to replace the existing universal shelf registration. Under new rules, NW Natural may designate the amount of securities to be registered at the time of issuance.

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Neither our Mortgage and Deed of Trust nor the Indenture under which other long-term debt may be issued contain credit rating triggers or stock price provisions that require the acceleration of debt repayment. Also, there are no rating triggers or stock price provisions contained in contracts or other agreements with third parties, except for agreements with certain counterparties under our Financial Derivatives Policy, which may require the affected party to provide substitute collateral such as cash, guaranty or letters of credit if credit ratings are lowered to non-investment grade, or in some cases if the mark-to-market value exceeds a certain threshold.

Based on the availability of short-term credit facilities and our expectation of being able to issue long-term debt and equity securities, we believe there is sufficient liquidity to satisfy our anticipated cash requirements, including the contractual obligations and investing and financing activities discussed below.

Dividend Policy

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. The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. It is the intention of the Board of Directors to continue to pay cash dividends on common stock on a quarterly basis. However, the declarations and amounts 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, 2007 by maturity and type of obligation.

	Payments Due in Years Ending December 31,						
Thousands	2008	2009	2010	2011	2012	Thereafter	Total
Commercial paper	$ 143,100	$ -	$ -	$ -	$ -	$ -	$ 143,100
Long-term debt maturities	5,000	-	35,000	10,000	40,000	427,000	517,000
Interest on long-term debt	33,632	33,417	33,406	30,858	28,536	313,056	472,905
Postretirement benefit payments(1)	16,603	17,345	18,510	19,063	19,857	110,959	202,337
Capital leases	532	393	255	26	-	-	1,206
Operating leases	4,257	4,184	4,177	4,140	4,265	32,003	53,026
Gas purchase contracts(2)	302,709	118,936	53,253	24,106	24,106	44,193	567,303
Gas pipeline commitments	82,348	63,526	61,090	64,989	49,977	131,501	453,431
Other purchase commitments	27,683	1,421	14	-	-	-	29,118
Total	$ 615,864	$ 239,222	$ 205,705	$ 153,182	$ 166,741	$ 1,058,712	$ 2,439,426

(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, 2007.

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.

Holders of certain long-term debt have put options that, if exercised, would require repurchases of up to $20 million principal amount in each of 2008 and 2009. If repurchased prior to maturity, then the interest obligation shown in the above table would be reduced in future years. The interest rate on the long-term debt issues with put options ranges between 6.65 percent and 7.05 percent.

In February 2008, we extended the term of an agreement with Northwest Pipeline for approximately 350,000 therms per day of firm transportation capacity from the U.S. Rocky Mountain region through 2044. Also in February 2008, we executed an agreement with a third party to take assignment of their firm gas supply transportation contract starting no earlier than 2012 and no 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.

In March 2004, our employees who are members of the Office and Professional Employees International Union, Local No. 11, approved a labor agreement (Joint Accord) covering wages, benefits and working conditions. This contract will expire on May 31, 2009.

Commercial Paper

Our primary source of short-term funds is from 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 commercial paper program is supported by committed lines of credit (see Credit Agreement, below). We had $143.1 million in commercial paper notes outstanding at December 31, 2007, compared to $100.1 million at December 31, 2006.

Credit Agreement

In May 2007, we entered into a credit agreement for unsecured revolving loans totaling $250 million with a syndication of lenders, replacing the prior $200 million bilateral credit agreements which were terminated. The new credit agreement is available and committed for a term of five years expiring on May 31, 2012, which may be extended for additional one-year periods thereafter subject to lender approval. The credit agreement allows us to request increases in the total commitment amount, up to a maximum amount of $400 million. The credit agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. The credit agreement continues to be used primarily as back-up credit support for the notes payable issued under our commercial paper program. Commercial paper borrowing provides the liquidity to meet our working capital and interim financing requirements. Under the terms of the credit agreement, we pay upfront fees, annual commitment fees and administrative agent fees, but we are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under the credit agreement are based on our long-term unsecured debt ratings and on then-current market interest rates. All principal and unpaid interest under the credit agreement is due and payable on May 31, 2012, subject to extensions if any. There were no outstanding balances on this credit agreement at December 31, 2007 or on prior credit agreements at December 31, 2006.

The credit agreement requires that we maintain credit ratings with Standard & Poor s (S&P) and Moody s Investors Service, Inc. (Moody s) and notify the lenders of any change in our senior unsecured debt ratings 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, 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.

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, 2007. Our previous credit agreements required us to maintain an indebtedness to total capitalization ratio of 65 percent or less, which we were in compliance with at December 31, 2006.

Credit Ratings

The table below summarizes our 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-	A2
Senior unsecured (long-term debt)	A+	A3
Ratings outlook	Stable	Positive

In July 2007, Moody s revised our ratings outlook from Stable to Positive. Both of the rating agencies have assigned us an investment grade rating. These credit ratings and ratings outlook 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 our securities. Each rating should be evaluated independently of any other rating.

Redemptions of Long-Term Debt

We redeemed long-term debt during 2007, 2006 and 2005 as follows:

Thousands	Redeemed in 2007	Redeemed in 2006	Redeemed in 2005
Medium-Term Notes			
6.34% Series B due 2005	$ -	$ -	$ 5,000
6.38% Series B due 2005	-	-	5,000
6.45% Series B due 2005	-	-	5,000
6.05% Series B due 2006	-	8,000	-
6.31% Series B due 2007	20,000	-	-
6.80% Series B due 2007	9,500	-	-
Convertible Debentures			
7.25% Series due 2012	-	-	528

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Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements and other cash and non-cash adjustments to operating results. In 2007, cash flow from net income and operating activity adjustments, excluding working capital changes, increased by $23.0 million. Working capital changes in 2007 increased cash flow by $12.1 million.

In 2006, our cash flow from net income and operating activity adjustments, excluding working capital changes, increased by $44.6 million, primarily due to a $31.0 million decrease in cash contributions to our qualified defined benefit pension plans and a $18.2 million increase in cash collections from deferred gas costs and improved operating results, partially offset by a decrease in deferred income tax benefits reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus depreciation. Working capital changes in 2006 increased cash flow by $24.9 million.

The overall change in cash flow from operating activities in 2007 compared to 2006 was an increase of $35.1 million. The overall change in cash flow from operations in 2006 was an increase of $69.5 million compared to 2005. The significant factors contributing to the cash flow changes between years are as follows:

2007 compared to 2006:

- an increase in net income added $11.1 million to cash flow;
- an increase in cash of $11.2 million related to a smaller reduction in 2007 in deferred income taxes compared to 2006;
- the increase in regulatory liabilities in 2007 related to deferred gas costs increased cash flow by $17.9 million, reflecting deferral activity between the two years with respect to purchased gas cost savings and off-system gas sales under our PGA tariff;
- a decrease in cash flow of $17.5 million due to change in deferred regulatory and other costs;
- an increase of $25.8 million due to a decrease in 2007 in accounts receivable and accrued unbilled revenue at year end compared to an increase in 2006;
- a decrease of $13.4 million in 2007 compared to 2006 resulting from income tax refunds received during 2006;
- an increase in accounts payable in 2007 compared to a decrease in 2006, increased cash $27.5 million;
- a decrease of $9.8 million in 2007 due to an increase in gas inventory in 2007 compared to a decrease in 2006; and
- a decrease of $16.6 million from a decrease in accrued taxes due to higher cash payments in 2007.

2006 compared to 2005:

- an increase in net income added $5.3 million to cash flow;
- a decrease in cash of $26.0 million related to a deferred income tax benefit in 2006 compared to a deferred income tax expense in 2005;

- the change to regulatory liabilities in 2006 from regulatory receivables in 2005 related to deferred gas costs increased cash flow by $18.2 million, reflecting deferral activity between the two years with respect to purchased gas cost savings and off-system gas sales under our PGA tariff;
- cash increased by $31.0 million in 2006 compared to 2005 due to the 2005 cash contributions to our qualified defined benefit pension plans;
- an increase in cash in 2006 of $36.5 million due to a decrease in accounts receivable and accrued unbilled revenue related to warmer weather around year end;
- an increase of $27.7 million in cash resulting primarily from a decrease in gas inventory costs in 2006 compared to 2005;
- a decrease in income taxes receivable contributed $10.5 million to cash in 2006;
- a reduction in accounts payable decreased cash $54.5 million in 2006 primarily due to lower gas prices around year end;
- a reduction in prepayments increased cash $6.4 million in 2006; and
- an increase in deferred regulatory liabilities increased cash by $11.3 million in 2006.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations (see Liquidity and Capital Resources Contractual Obligations, above, and Note 12).

Investing Activities

Cash requirements for investing activities in 2007 totaled $117.5 million, up from $90.6 million in 2006. Cash requirements for the acquisition and construction of utility plant were $93.8 million in 2007, down slightly from $95.3 million in 2006. Cash requirements for investments in non-utility property increased to $29.9 million in 2007, compared to $1.8 million in 2006, primarily related to investments in Mist gas storage, Gill Ranch and Palomar Pipeline.

Cash requirements for investing activities in 2006 totaled $90.6 million, down slightly from $92.0 million in 2005. Cash requirements for the acquisition and construction of utility plant totaled $95.3 million, up from $89.3 million in 2005. The increase in cash requirements for utility construction in 2006 primarily reflected $12.5 million of capital expenditures in 2006 for an automated meter reading system, which was completed in 2007.

Investments in our pipeline integrity management program were $11.5 million in 2007, compared to $11.0 million in 2006 and $6.1 million in 2005. These costs are estimated at approximately $50 million to $100 million over a 10-year period through 2012. The costs are accumulated over each 12 months ending September 30, and the capitalized costs, subject to audit, are recovered through the annual PGA based on adjustments to rate base each year. The approved regulatory accounting and rate treatment for these costs extends through September 30, 2008, and may be reviewed for potential extension after that date.

During the five-year period 2008 through 2012, utility construction expenditures are estimated at between $500 and $600 million. The estimated level of capital expenditures over the next five years reflects 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 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.

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Our utility and non-utility capital expenditures for 2008 are estimated to total between $90 million and $100 million. This estimate does not include costs of the potential Palomar Pipeline or Gill Ranch projects, or other investments that may be driven by our business process redesign (see Strategic Opportunities, above). In December 2003, the U.S. Department of Transportation s Office of Pipeline Safety (now the Pipeline Hazardous Materials Safety Administration) issued a rule that specifies the detailed requirements for transmission pipeline integrity management plans as mandated by the Pipeline Safety Act. See Part I., Item 1., Pipeline Safety. We continued to achieve our milestones, completing the required inspection of the top 50 percent highest risk transmission pipelines in 2007. We are currently on track to meet the next milestone to complete the inspection of all transmission pipelines in HCAs by December 2012.

Financing Activities

Cash used in financing activities in 2007 totaled $65.8 million, as compared to $59.4 million in 2006. Factors contributing to the $6.4 million net increase in cash used include an increase in share repurchases of $28.7 million, an increase in long-term debt retired of $21.5 million, and a reduction in long-term debt issuances of $25.0 million, offset by an increase in cash from the change in short-term debt balances of $69.6 million in 2007 compared to 2006.

Cash used in financing activities in 2006 totaled $59.4 million, as compared to cash provided by financing in 2005 of $14.8 million. Factors contributing to the $74.2 million net change were the net change in short-term debt of $50.8 million, $25.0 million less of long-term debt issued during 2006 and $3.6 million less equity financing in 2006, partially offset by $7.5 million less redemptions of long-term debt in 2006 compared to 2005.

In October 2007, we entered into a forward-starting interest rate swap with a notional principal amount of $50 million. This fixed-rate forward-starting swap is intended to mitigate a substantial portion of the interest rate exposure associated with our anticipated issuance of MTNs during the second half of 2008 when we would expect to cash settle this contract. The associated gain or loss on settlement will be recorded as a regulatory asset or liability and amortized in accordance with regulatory requirements. We did not issue any new long-term debt during 2007.

In December 2006, we sold $25 million of 5.15% Series B, secured MTNs due 2016 and used the proceeds to reduce short-term indebtedness and to fund utility construction.

In 2005, we sold $40 million of 4.70% Series B, secured MTNs due 2015 and $10 million of 5.25% Series B, secured MTNs due 2035, and used the proceeds to redeem long-term debt, to reduce short-term indebtedness and to make investments in utility plant.

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 2006 that program was modified to 2.6 million shares and $85 million in value, and the program was further increased in 2007 to 2.8 million shares and $100 million and extended through May 2008. The purchases are made in the open market or through privately negotiated transactions. Repurchases pursuant to the program in 2007 totaled 963,428 shares or $44.2 million; in 2006 totaled 395,500 shares or $16.0 million; and in 2005 totaled 410,200 shares, or $14.9 million. Since the program s inception, we have repurchased an aggregate 2,124,528 shares of common stock at a total cost of $83.3 million (see Part II, Item 5, Market for the Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, above).

In 2007, we produced free cash flow of $27.5 million, compared to free cash flow of $19.7 million in 2006. In 2005 we had negative free cash flow of $49.3 million. 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 (year ended December 31)	2007	2006	2005
Cash provided by operating activities	$ 183,640	$ 148,566	$ 79,066
Cash used in investing activities	(117,479)	(90,567)	(92,008)
Cash dividend payments on common stock	(38,613)	(38,298)	(36,376)
Free cash flow	$ 27,548	$ 19,701	$ (49,318)

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

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Generally, it is our policy to contribute at least the minimum amount required by Internal Revenue Code regulations and the Employee Retirement Income Security Act of 1974. It is also our intent to contribute additional amounts sufficient on a sound actuarial basis to maintain funding targets and provide for the payment of future benefits under the plans. Our qualified defined pension plans are currently funded at nearly 100 percent of the projected benefit obligation at December 31, 2007. For more information see Note 7.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2007, 2006 and 2005, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.92, 3.40 and 3.32, 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.

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 SFAS No. 5, Accounting for Contingencies, (see Application of Critical Accounting Policies and Estimates Contingencies, above). At December 31, 2007, a cumulative $63.1 million in environmental costs was recorded as a regulatory asset, consisting of $24.8 million of costs paid to-date, $35.1 million for additional environmental accruals for costs expected to be paid in the future and accrued regulatory interest of $3.2 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs is 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 12.

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New Accounting Pronouncements

For a description of recent accounting pronouncements that may have an impact on our financial condition, results of operations or cash flows, see Note 1.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, weather risk and interest rate 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. Historically, we have taken physical delivery of at least the minimum quantities specified in our natural gas supply contracts. These contracts are primarily index-based and subject to annual re-pricing, a process that is intended to reflect anticipated market price trends during the next year. Our PGA mechanisms in Oregon and Washington provide for the recovery from customers of actual commodity costs, except that, for Oregon customers, we absorb 33 percent of the higher cost of gas sold, or retain 33 percent of the lower cost, in either case as compared to the annual PGA price built into customer rates.

Market risks related to potential adverse changes in commodity prices, interest rates, foreign exchange rates or counterparty credit quality in relation to these financial and physical contracts are discussed below.

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion and other factors that affect short-term supply and demand. Commodity-price swap, put and call option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed prices. These financial hedge contracts are generally included in our annual PGA filing, subject to a prudency review. At December 31, 2007 and 2006, notional amounts under these commodity swap, put and call option contracts totaled $287.6 million and $349.7 million, respectively. If the related financial derivative contracts had been settled on December 31, 2007, a regulatory loss of $ 12.8 million would have been realized and deferred (see Note 11). The $12.8 million unrealized loss is an estimate of future cash flows that are expected to be paid as follows: $10.5 million in 2008 and $2.3 million by October 31, 2009. The amount realized will change based on market prices at the time contracts settle. We monitor the liquidity of our financial derivative contracts and, based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our commodity financial hedge contracts settle by October 31, 2009.

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 hedge products, to manage and mitigate interest rate exposure. During the fourth quarter of 2007, we entered into a forward starting interest rate swap with a notional amount of $50 million to hedge the interest rate on our next long-term debt issuance, which is expected to occur in the latter part of 2008.

This swap is with an AA/Aaa rated counterparty and qualifies as a cash flow hedge under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133).

Holders of certain long-term debt have put options that, if exercised, would accelerate maturities by $20 million in each of 2008 and 2009 (see Note 5 and Note 11).

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 the purchases of natural gas from Canadian suppliers. At December 31, 2007 and 2006, notional amounts under foreign currency forward contracts totaled $6.1 million and $5.0 million, respectively. As of December 31, 2007, no foreign currency forward contracts extended beyond December 31, 2008. If all of the foreign currency forward contracts had been settled on December 31, 2007, a gain of $0.1 million would have been realized (see Note 11).

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. We evaluate and continuously 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, 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.

Credit exposure to financial derivative counterparties. Periodically we may have credit exposure to financial derivative counterparties based on the estimated fair value of derivative contracts outstanding. At December 31, 2007, in aggregate our financial derivative counterparties owed us $0.1 million while we owed our counterparties a net $14.1 million. Our Financial Derivatives Policy requires counterparties to have a specified minimum credit rating at the time the derivative instrument is entered into, and the policy sets forth limits on the contract amount and duration based on each counterparty s credit rating.

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The following table summarizes our 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 S&P or Moody s rating, or a middle rating if the entity is split-rated more than one rating level:

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)	
Thousands	Dec. 31, 2007	Dec. 31, 2006
AAA/Aaa	$ (309)	$ -
AA/Aa	(13,941)	(40,955)
A/A	123	-
BBB/Baa	-	-
Total	$ (14,127)	$ (40,955)

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 utilize various collateral management strategies to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in any 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. During 2007, we neither called for nor posted collateral with any of our derivative counterparties. Our derivative credit exposure is primarily with investment grade banks rated AA-/Aa3 or higher. Contracts are diversified across counterparties to reduce credit and liquidity risk.

Credit exposure to customers. In the short term, market prices for natural gas have moderated and resulted in some of our large industrial customers changing from sales services to transportation service. Under sales service, the customer purchases both its gas commodity supply and transportation service from us. Under transportation service, the customer purchases its commodity supplies from an independent third party, while we provide the transportation service for delivery of that gas to the customer s premise. As a result of this migration from sales service to transportation service, our credit exposure to large industrial customers is expected to moderate. We monitor and manage the credit exposure of our industrial customers through credit policies and procedures, which are designed to reduce credit risk. These policies and procedures include an ongoing review of credit risks, including changes in the services provided to industrial customers as well as changes in market conditions and customers credit quality. Changes in credit risk may require us to obtain additional assurance, such as deposits, letters of credit, guarantees and prepayments, to reduce our credit exposure.

We also monitor and manage the credit exposure of our residential and commercial customers. This credit risk is largely mitigated by the nature of our regulated business and reasonably short collection terms, as well as by the consistent application of our credit policies and procedures.

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

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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 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, 2007, about 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.

Forward-Looking Statements

This report and other presentations made by us from time to time may contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and other statements that are other than statements of historical facts. Our expectations, beliefs and projections are expressed in good faith and are believed to have a reasonable basis. However, each forward-looking statement involves uncertainties and is qualified in its entirety by reference to the following important factors, among others, that could cause our actual results to differ materially from those projected, including:

- prevailing state and federal governmental policies and regulatory actions with respect to allowed rates of return, industry and rate structure, purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, present or prospective wholesale and retail competition, changes in tax laws and policies and changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity;
- application of the OPUC rules interpreting Oregon legislation intended to ensure that utilities do not collect more income taxes in rates than they actually pay to government entities;
- weather conditions, pandemic events and other natural phenomena, including earthquakes or other geohazard events;
- unanticipated population growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;
- competition for retail and wholesale customers;
- market conditions and pricing of natural gas relative to other energy sources;
- the creditworthiness of customers, suppliers and financial derivative counterparties;
- our dependence on a single pipeline transportation provider for natural gas supply;
- property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;
- financial and operational risks relating to business development and investment activities, including the proposed natural gas pipeline project with GTN and the proposed Gill Ranch storage facility;
- unanticipated changes that may affect our liquidity or access to capital markets;

- our ability to maintain effective internal controls over financial reporting in compliance with Section 404 of the Sarbanes-Oxley Act of 2002;
- unanticipated changes in interest or foreign currency exchange rates or in rates of inflation;
- economic factors that could cause a severe downturn in certain key industries, thus affecting demand for natural gas;
- unanticipated changes in operating expenses and capital expenditures;
- changes in estimates of potential liabilities relating to environmental contingencies;
- unanticipated changes in future liabilities relating to employee benefit plans, including changes in key assumptions;
- capital market conditions, including their effect on financing costs, the fair value of pension assets and on pension and other postretirement benefit costs;
- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions; and
- legal and administrative proceedings and settlements.

All subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NW Natural, also are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for us to predict all such factors, nor can we assess the impact of each such factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

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

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions 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, 2007. 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, 2007.

The effectiveness of internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

/s/ Mark S. Dodson
Mark S. Dodson
Chief Executive Officer

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

February 29, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Northwest Natural Gas Company:

In our opinion, the consolidated financial statements listed in the accompanying table of contents present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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, 2007, 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 the 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 share based compensation in 2006. As discussed in Note 7 to the consolidated financial statements, the Company changed the manner in which it accounts for defined benefit pension and other postretirement plans effective December 31, 2006.

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 the board of directors of the company; and

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(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 29, 2008

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NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME

Thousands, except per share amounts (year ended December 31)	2007	2006	2005
Operating revenues:			
Gross operating revenues	$ 1,033,193	$ 1,013,172	$ 910,486
Less: Cost of sales	639,150	648,156	563,860
Revenue taxes	25,001	24,840	21,633
Net operating revenues	369,042	340,176	324,993
Operating expenses:			
Operations and maintenance	120,488	114,560	113,216
General taxes	25,288	24,419	23,185
Depreciation and amortization	68,343	64,435	61,645
Total operating expenses	214,119	203,414	198,046
Income from operations	154,923	136,762	126,947
Other income and expense - net	1,445	2,134	1,205
Interest charges - net of amounts capitalized	37,811	39,247	37,283
Income before income taxes	118,557	99,649	90,869
Income tax expense	44,060	36,234	32,720
Net income	$ 74,497	$ 63,415	$ 58,149
Average common shares outstanding:			
Basic	26,821	27,540	27,564
Diluted	26,995	27,657	27,621
Earnings per share of common stock:			
Basic	$ 2.78	$ 2.30	$ 2.11
Diluted	$ 2.76	$ 2.29	$ 2.11

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2007	2006
Assets:		
Plant and property:		
Utility plant	$ 2,052,161	$ 1,963,498
Less accumulated depreciation	615,533	574,093
Utility plant - net	1,436,628	1,389,405
Non-utility property	67,149	42,652
Less accumulated depreciation and amortization	7,904	6,916
Non-utility property - net	59,245	35,736
Total plant and property	1,495,873	1,425,141
Current assets:		
Cash and cash equivalents	6,107	5,767
Accounts receivable	69,442	82,070
Accrued unbilled revenue	78,004	87,548
Allowance for uncollectible accounts	(2,890)	(3,033)
Regulatory assets	17,598	31,509
Fair value of non-trading derivatives	2,903	5,109
Inventories:		
Gas	71,079	68,576
Materials and supplies	8,865	9,552
Income taxes receivable	122	-
Prepayments and other current assets	25,569	21,695
Total current assets	276,799	308,793
Investments, deferred charges and other assets:		
Regulatory assets	175,938	164,771
Fair value of non-trading derivatives	324	1,448
Other investments	54,070	47,985
Other	11,179	8,718
Total investments, deferred charges and other assets	241,511	222,922
Total assets	$ 2,014,183	$ 1,956,856

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2007	2006
Capitalization and liabilities:		
Capitalization:		
Common stock	$ 331,595	$ 371,127
Earnings invested in the business	266,658	230,774
Accumulated other comprehensive income (loss)	(3,502)	(2,356)
Total common stock equity	594,751	599,545
Long-term debt	512,000	517,000
Total capitalization	1,106,751	1,116,545
Current liabilities:		
Notes payable	143,100	100,100
Long-term debt due within one year	5,000	29,500
Accounts payable	119,731	113,579
Taxes accrued	13,259	21,230
Interest accrued	2,827	2,924
Regulatory liabilities	61,326	11,919
Fair value of non-trading derivatives	14,829	38,772
Other current and accrued liabilities	29,794	21,455
Total current liabilities	389,866	339,479
Deferred credits and other liabilities:		
Deferred income taxes and investment tax credits	206,340	210,084
Regulatory liabilities	213,764	202,982
Pension and other postretirement benefit liabilities	41,619	52,690
Fair value of non-trading derivatives	3,758	11,031
Other	52,085	24,045
Total deferred credits and other liabilities	517,566	500,832
Commitments and contingencies (see Note 12)	-	-
Total capitalization and liabilities	$ 2,014,183	$ 1,956,856

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY AND

COMPREHENSIVE INCOME

Thousands	Common Stock and Premium	Earnings Invested in the Business	Unearned Stock Compensation	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity	Comprehensive Income
Balance at Dec. 31, 2004	$ 387,265	$ 183,932	$ (862)	$ (1,818)	$ 568,517	
Net Income	-	58,149	-	-	58,149	$ 58,149
Minimum pension liability adjustment, net of $59 of tax	-	-	-	(93)	(93)	(93)
Restricted stock amortizations	-	-	212	-	212	
Dividends paid on common stock	-	(36,376)	-	-	(36,376)	
Tax benefits from employee stock option plan	220	-	-	-	220	
Issuance of common stock	7,266	-	-	-	7,266	
Common stock repurchased	(14,945)	-	-	-	(14,945)	
Convertible debentures	3,999	-	-	-	3,999	
Common stock expense	-	(18)	-	-	(18)	
Balance at Dec. 31, 2005	383,805	205,687	(650)	(1,911)	586,931	$ 58,056
Net Income	-	63,415	-	-	63,415	$ 63,415
Minimum pension liability adjustment, net of $52 of tax	-	-	-	(81)	(81)	(81)
Recognition of non-qualified employee benefit plan liability, net of $232 of tax			(364)	(364)		
Restricted stock amortizations	298	-	-	-	298	
Dividends paid on common stock	-	(38,298)	-	-	(38,298)	
Tax benefits from employee stock option plan	317	-	-	-	317	
Stock-based compensation	555	-	-	-	555	
Restricted stock reclassification	(650)	-	650	-	-	
Issuance of common stock	2,773	-	-	-	2,773	
Common stock repurchased	(15,971)	-	-	-	(15,971)	
Common stock expense	-	(30)	-	-	(30)	
Balance at Dec. 31, 2006	371,127	230,774	-	(2,356)	599,545	$ 63,334
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

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

Thousands (year ended December 31)	2007	2006	2005
Operating activities:			
Net income	$ 74,497	$ 63,415	$ 58,149
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	68,343	64,435	61,645
Deferred income taxes and investment tax credits	(5,252)	(16,440)	9,551
Undistributed earnings from equity investments	(130)	(191)	(57)
Deferred gas costs - net	38,665	20,752	2,577
Gain on sale of non-utility investments	(1,544)	(495)	-
Income from life insurance investments	(1,939)	(2,609)	(1,873)
Contributions to qualified defined benefit pension plans	-	-	(31,000)
Non-cash expenses related to qualified defined benefit pension plans	4,387	5,500	4,532
Deferred environmental expenditures	(8,842)	(6,675)	(9,132)
Deferred regulatory costs and other	(2,940)	14,533	3,243
Changes in working capital:			
Accounts receivable and accrued unbilled revenue - net	22,029	(3,722)	(40,262)
Inventories of gas, materials and supplies	(1,816)	8,033	(19,684)
Income taxes receivable	(122)	13,234	2,736
Prepayments and other current assets	(6,528)	2,952	(3,439)
Accounts payable	5,841	(21,708)	32,809
Accrued interest and taxes	(8,068)	8,511	2,504
Other current and accrued liabilities	7,059	(959)	6,767
Cash provided by operating activities	183,640	148,566	79,066
Investing activities:			
Investment in utility plant	(93,785)	(95,307)	(89,259)
Investment in non-utility property	(24,442)	(1,773)	(6,842)
Proceeds from sale of non-utility investments	2,628	2,517	3,001
Proceeds from life insurance	881	4,009	296
Contributions to non-utility equity investments	(5,413)	-	-
Other	2,652	(13)	796
Cash used in investing activities	(117,479)	(90,567)	(92,008)
Financing activities:			
Common stock issued, net of expenses	2,180	3,913	7,486
Common stock repurchased	(44,627)	(15,971)	(14,945)
Long-term debt issued	-	25,000	50,000
Long-term debt retired	(29,500)	(8,000)	(15,528)
Change in short-term debt - net	43,000	(26,600)	24,200
Cash dividend payments on common stock	(38,613)	(38,298)	(36,376)
Other	1,739	581	-
Cash (used in) provided by financing activities	(65,821)	(59,375)	14,837
Increase (decrease) in cash and cash equivalents	340	(1,376)	1,895
Cash and cash equivalents - beginning of period	5,767	7,143	5,248
Cash and cash equivalents - end of period	$ 6,107	$ 5,767	$ 7,143

Supplemental disclosure of cash flow information:			
Interest paid	$ 38,508	$ 39,294	$ 36,974
Income taxes paid	$ 56,215	$ 31,270	$ 28,479
Supplemental disclosure of non-cash financing activities:			
Conversions to common stock:			
7-1/4 % Series of Convertible Debentures	$ -	$ -	$ 3,999

See Notes to Consolidated Financial Statements.

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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, and other businesses which primarily consist of our wholly-owned subsidiary businesses including NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch), and a joint venture in a natural gas transmission pipeline (See Note 2).

In this report, the term utility is used to describe the regulated 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 by regulatory accounting under Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, not to be eliminated.

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 (see Note 9).

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 business is the distribution of natural gas, which is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Accounting records and practices of the regulated business conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with SFAS No. 71. The utility business segment is authorized by the OPUC and the WUTC to earn a reasonable return on invested capital.

In applying SFAS No. 71, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC in general rate case or other deferral proceedings, for example, our purchased gas adjustment (PGA) mechanism, to provide for recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge.

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At December 31, 2007 and 2006, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		Non-Current	
Thousands	2007	2006	2007	2006
Regulatory assets:				
Unrealized loss on non-trading derivatives[1]	$ 14,788	$ 30,798	$ 3,758	$ 9,584
Income tax asset	-	-	68,649	67,141
Pension and other postretirement benefit obligations[2]	1,912	-	27,152	54,425
Environmental costs - paid[3]	-	-	27,956	19,113
Environmental costs - accrued but not yet paid[3]	-	-	35,098	8,760
Other[4]	898	711	13,325	5,748
Total regulatory assets	$ 17,598	$ 31,509	$ 175,938	$ 164,771
Regulatory liabilities:				
Gas costs payable[5]	$ 46,153	$ 737	$ 6,290	$ 13,041
Unrealized gain on non-trading derivatives[1]	2,903	-	324	-
Accrued asset removal costs	-	-	204,886	187,422
Other[4]	12,270	11,182	2,264	2,519
Total regulatory liabilities	$ 61,326	$ 11,919	$ 213,764	$ 202,982

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 PGA mechanism.

2 Qualified pension plan and other postretirement costs 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 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 approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

5 A majority of gas costs deferred earn a rate of return or carrying charge.

We believe that continued application of SFAS No. 71 for regulated activities is appropriate and consistent with the current regulatory environment, and that all regulated assets and liabilities at December 31, 2007 and 2006 are 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 SFAS No. 71, then we would be required to write off the net unrecoverable balances against earnings.

New Accounting Standards

Adopted Standards

Accounting for Uncertainty in Income Taxes. On January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109, which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. As a result of the implementation of FIN 48, we recognized no change in our recorded assets or liabilities for unrecognized income tax benefits. Based on our analysis of all material tax positions taken, management believes the technical merits of these positions are justified and expects that the full amount of the deductions taken and associated tax benefits will be allowed.

FIN 48 requires the evaluation of a tax position as a two-step process. We must determine whether it is more likely than not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the more likely than not recognition threshold, then the tax benefit is measured and recorded at the largest amount that is greater than 50 percent likely of being realized upon effective settlement. The re-assessment of our tax positions in accordance with FIN 48 did not result in any material change to our financial condition, results of operations or cash flows.

FIN 48 prescribes that a company recognize the benefit of a tax position when it is effectively settled. In May 2007, FASB Staff Position (FSP) FIN 48-1, Definition of Settlement in FASB Interpretation No. 48, was issued to provide guidance on how to determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. The provisions of FSP FIN 48-1 did not change the conclusions reached during our adoption of FIN 48.

We are subject to U.S. federal income taxes as well as several state and local income taxes. All of our U.S. federal income tax matters audited by the Internal Revenue Service through the 2004 tax year were concluded during 2006 with no material adjustments. Also, substantially all material state and local income tax matters are closed through the 2003 tax year. Based upon our assessment in connection with the adoption of FIN 48, we do not believe there are any tax positions taken that would not be fully sustained upon audit.

We have also assessed the classification of interest and penalties, if any, related to income tax matters. Pursuant to the application of FIN 48, we have made an accounting policy election to treat interest and penalties related to income tax matters, if any, as a component of income tax expense rather than other operating expenses. See Note 8.

Accounting for Certain Hybrid Instruments. In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Instruments, which amended SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, a replacement of FASB Statement No. 125. SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for as a whole if the holder elects to account for the whole instrument on a fair value basis. SFAS No. 155 is effective for all financial instruments acquired or issued after January 1, 2007. The adoption and implementation of SFAS No. 155 did not have an impact on our financial condition, results of operations or cash flows.

Recent Accounting Pronouncements

Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which provides a common definition for the measurement of fair value for use

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in applying GAAP and in preparing financial statement disclosures. Most of SFAS No. 157 is effective as of the beginning of the first annual period after November 15, 2007, or January 1, 2008. However, implementation of the fair value measurement of liabilities applicable to us has been delayed until the beginning of the first annual period after November 15, 2008. This pronouncement replaces the definition of price used to determine fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction. To increase consistency and comparability, it also establishes a hierarchy of inputs used to calculate fair value, ranging from level one (observable) to level three inputs (unobservable).

New disclosures under SFAS No. 157 will primarily consist of:

- A description of the fair value measurements at the reporting date;
- A description of the inputs for fair value calculations;
- A description of the level of each input within the fair value hierarchy, segregated by input level;
- A tabular reconciliation for all level three inputs illustrating the total gains and losses, purchases or sales, and transfers into or out of level three;
- A tabular detail of the gains and losses for the period; and,
- A description of the valuation techniques used to measure fair value and a discussion of changes in valuation techniques, if any.

Adoption of SFAS No. 157 will require us to identify the inputs for our fair value calculations according to the fair value hierarchy, increase coordination with our external service providers and provide more detailed disclosure. Based on our preliminary assessment, the adoption of SFAS No. 157 is not expected to have a material effect on our financial condition, results of operations or cash flow.

Fair Value Option for Financial Assets and Liabilities. In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. Based on our preliminary evaluation, the adoption and implementation of SFAS No. 159 is not expected to have a material effect on our financial condition, results of operations or cash flow.

Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. In November 2006, the Emerging Issues Task Force (EITF) issued EITF 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards, which provides the accounting requirements for the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options, and how these benefits are charged to retained earnings under SFAS No. 123R, Share Based Payment. EITF 06-11 is effective as of the beginning of the first annual period starting after December 15, 2007.

EITF 06-11 will require us to adjust our current accounting policy on the recognition of the income tax benefit received on dividends paid to employees. Based on our preliminary evaluation, the adoption of EITF 06-11 is not expected to have a material impact on our financial condition, results of operations or cash flow.

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Plant and Property and Accrued Asset Removal Costs

Plant and property is stated at cost, including capitalized labor, materials and overhead (see Note 9). The cost of constructing utility plant and gas storage assets includes an allowance for funds used during construction (AFUDC), which represents the net financing cost during the period the funds are used for construction purposes (see Allowance for Funds Used During Construction, below).

Our provision for depreciation of utility property is computed under the straight-line, age-life method in accordance with independent engineering studies and as approved by regulatory authorities. The weighted average depreciation rate for utility plant in service was approximately 3.4 percent for each of the years ended December 31, 2007, 2006 and 2005, 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 our most recent depreciation study. 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 the net rate base.

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. 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 5.4 percent in 2007, 4.7 percent in 2006 and 3.1 percent in 2005.

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, 2007 and 2006, book overdrafts of $4.9 million and $3.7 million, respectively, were included within accounts payable.

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 and weather. Accrued unbilled revenues are reversed the following month when actual billings occur. Our accrued unbilled revenues at December 31, 2007 and 2006 were $78.0 million and $87.5 million, respectively.

Utility revenues may 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 the tax year.

Non-utility revenues, derived primarily from gas storage services, are recognized upon delivery of the service to customers. Revenues from optimization of excess storage and transportation capacity include amounts that are recognized ratably over the life of the contract for guaranteed amounts, or as earned for amounts above the guaranteed amount based on the terms of our contract with the independent energy marketing company which optimizes the value of our assets primarily through the use of commodity transactions and capacity release transactions. 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 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 past due accounts on 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 the uncollectible accounts is adjusted, if necessary, based on the most current information available.

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 full cost recovery in customer rates, subject to a prudency review, including any differences between the actual purchase cost of gas injected into inventory and the embedded cost of inventory in current rates. All gas that is injected into storage is priced into inventory at the actual purchase cost based on a regulatory dispatch model for our gas purchases. All gas that is withdrawn from inventory is charged to cost of gas during the current period at the weighted average cost of inventory embedded in customer rates, which is established in our annual PGA filing. Material and supplies inventories are stated at the lower of average cost or net realizable value.

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Derivatives

In accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities, and SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities (collectively referred to as SFAS No. 133), we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. SFAS No. 133 requires that changes in the fair value of a derivative be recognized currently in earnings unless specific hedge accounting criteria are met. SFAS No. 133 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 SFAS No. 71. Derivatives contracts entered into for core utility customer requirements after the PGA rate has been set are subject to the PGA incentive sharing mechanism, whereby 67 percent of the changes in fair value are deferred as regulatory assets or liabilities and the remaining 33 percent is 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 (see Note 11).

Our Financial Derivatives Policy sets 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 considered to be unavoidable because they 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.

Revenue Taxes

We account for 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 SFAS No. 109, Accounting for Income Taxes. SFAS No. 109 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).

SFAS No. 109 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 to $68.6 million and $67.1 million at December 31, 2007 and 2006, 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 SFAS No. 71, 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. Investment and energy tax credits generated by Financial Corporation are amortized over a period of one to five years.

Other Income and Expense Net

Other income and expense net consists of interest income, gain on sale of investments, investment income of Financial Corporation, investment expenses of our proposed pipeline project and other miscellaneous income from merchandise sales, rents, leases and other items.

Thousands	2007	2006	2005
Gains from company-owned life insurance	$ 1,939	$ 2,609	$ 1,856
Interest income	537	363	403
Earnings from equity investments of Financial Corporation	130	191	57
Gain on sale from equity investments	1,544	-	-
Other non-operating expenses	(2,789)	(852)	(1,393)
Net interest on certain deferred regulatory accounts	84	(177)	282
	$ 1,445	$ 2,134	$ 1,205

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	2007	2006	2005
Net income	$ 74,497	$ 63,415	$ 58,149
Average common shares outstanding - basic	26,821	27,540	27,564
Stock based compensation	174	117	57
Average common shares outstanding - diluted	26,995	27,657	27,621
Earnings per share of common stock - basic	$ 2.78	$ 2.30	$ 2.11
Earnings per share of common stock - diluted	$ 2.76	$ 2.29	$ 2.11

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For the years ended December 31, 2007, 2006 and 2005, 442 shares,105,600 shares and 6,000 shares, respectively, represent the number of stock options which were excluded from the calculation of diluted earnings per share because the effect was antidilutive.

Stock-Based Compensation

We periodically provide stock-based compensation to employees in the form of stock options and other incentive awards. As required by SFAS No. 123R, Share Based Compensation, we recognize the fair value of all share-based payments as compensation expense in the financial statements. Prior to January 1, 2006, as permitted by SFAS No. 123, we applied APB Opinion No. 25, Accounting for Stock Issued to Employees, to account for stock-based compensation. Accordingly, prior to January 1, 2006, we did not recognize compensation expense for the fair value of our stock option grants. We implemented SFAS 123R effective January1, 2006 by applying the modified prospective transition method. The impact on net income of this new standard, had it been adopted in 2005, is reflected in the pro forma amounts in Note 4.

2. CONSOLIDATED SUBSIDIARY OPERATIONS AND SEGMENT INFORMATION:

At December 31, 2007, we had two direct wholly-owned subsidiaries, Financial Corporation and Gill Ranch Storage, LLC.

Our core business segment is the local gas distribution segment, also referred to as the utility, which involves the distribution and sale of natural gas. Another business segment, gas storage, represents natural gas storage services provided to intrastate and interstate customers, and includes asset optimization services under a contract with an independent energy marketing company. The remaining business segment, other, primarily consists of wholly-owned subsidiaries, Financial Corporation and Gill Ranch, as well as various other non-utility investments, including an investment in a leveraged aircraft lease and our equity investment in a proposed natural gas pipeline project with TransCanada Gas Transmission Northwest (GTN). See Note 9.

Gas Storage

The gas storage business segment is primarily made up of underground natural gas storage services that we provide to large intra- and inter-state customers using our owned storage capacity at Mist that has been developed in advance of core utility customers requirements. In Oregon, we retain 80 percent of the income before tax from these services and credit the remaining 20 percent to a deferred regulatory account for sharing with core utility customers. For each of the years ended December 31, 2007, 2006 and 2005, this business segment derived a majority of its revenues from multi-year contracts with less than 10 customers. The largest of these customers is served under a long-term contract.

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 the our assets primarily through the use of commodity transactions and transportation capacity release transactions. In Oregon, we retain 80 percent of the pre-tax income 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 core utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for distribution to core utility customers. We have a similar sharing mechanism in Washington for revenue derived from storage and third party optimization.

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Other

In October 2007, Financial Corporation sold its investments in two wind power electric generating projects for $2.1 million, which resulted in an after-tax net gain on sale of $0.9 million. In addition, in December 2007, one low-income housing project investment reached the end of the contract period and our partnership interest was transferred pursuant to the original terms of the agreement.

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. Our capacity on this pipeline is contracted to NW Natural s utility operations. Financial Corporation s remaining assets totaled $1.4 million and $2.6 million at December 31, 2007 and 2006, respectively.

At December 31, 2006, we reclassified to current assets our net investment of $5.3 million in a Boeing 737-300 airplane leased to Continental Airlines. The original lease term expired in September 2007, and the aircraft lease was extended at the option of the lessee for 12 months. We are currently in negotiations to sell the airplane and expect it to be sold during 2008.

Segment Information Summary

The following table presents summary financial information about the reportable segments for 2007, 2006 and 2005. Inter-segment transactions are insignificant.

Thousands	Utility	Gas Storage	Other	Total
2007				
Net operating revenues	$ 351,875	$ 16,999	$ 168	$ 369,042
Depreciation and amortization	67,410	933	-	68,343
Income (loss) from operations	140,434	14,953	(464)	154,923
Income from financial investments	1,939	-	1,674	3,613
Net income	64,938	8,742	817	74,497
Total assets at Dec. 31, 2007	1,940,844	59,427	13,912	2,014,183
2006				
Net operating revenues	$ 327,267	$ 12,761	$ 148	$ 340,176
Depreciation and amortization	63,552	883	-	64,435
Income from operations	126,366	9,870	526	136,762
Income from financial investments	2,609	-	191	2,800
Net income	56,653	5,982	780	63,415
Total assets at Dec. 31, 2006	1,912,021	35,970	8,865	1,956,856
2005				
Net operating revenues	$ 315,248	$ 9,609	$ 136	$ 324,993
Depreciation and amortization	60,935	710	-	61,645
Income (loss) from operations	118,794	8,158	(5)	126,947
Income from financial investments	1,856	-	57	1,913
Net income	52,759	4,557	833	58,149

3. CAPITAL STOCK:

Common Stock

As of December 31, 2006 and 2007, we had 60,000,000 common shares authorized.

At December 31, 2007, we had reserved 223,033 shares of common stock for issuance under the Employee Stock Purchase Plan, 666,537 shares under our Dividend Reinvestment and Direct Stock Purchase Plan and 1,393,150 shares under our Restated Stock Option Plan (see Note 4).

In connection with the restatement of our Restated Articles of Incorporation, effective May 31, 2006, the par value of our common stock was eliminated. As a result, at December 31, 2007 and 2006, our common stock and premium on common stock account balances are reflected on the balance sheet as common stock.

Stock Repurchase Program

Our publicly announced stock repurchase program allows us to purchase up to 2.8 million shares, or up to $100.0 million in total, of our common stock in the open market or through privately negotiated transactions. We repurchased a total of 963,428, 395,500 and 410,200, shares under this program in 2007, 2006, and 2005, respectively. In addition, during the first half of 2007, we completed our voluntary oddlot share buyback program, which resulted in a net repurchase of 10,188 shares.

Restated Stock Option Plan

There are 2,400,000 shares authorized for option grants under the Restated Stock Option Plan. At December 31, 2007, options on 1,035,400 shares were available for grant and options on 357,750 shares were outstanding.

Convertible Debentures

In August 2005, we redeemed all of our outstanding Convertible Debentures, 7-1/4% Series due 2012, at 100 percent of their principal amount plus accrued interest to the date of redemption. During 2005, debentures with an aggregate principal amount of $4.0 million were converted into shares of common stock on or prior to the redemption date at the rate of 50.25 shares for each $1,000 principal amount of debentures and $0.5 million of debentures were redeemed.

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Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding and the premium on common stock for the years 2007, 2006 and 2005:

	Shares	Premium on common stock (thousands)
Balance, Dec. 31, 2004	27,546,720	$ 300,034
Sales to employees	30,896	741
Sales to stockholders	113,925	3,741
Exercise of stock options - net	97,068	2,241
Conversion of convertible debentures to common	200,887	3,360
Repurchase	(410,200)	(13,646)
Balance, Dec. 31, 2005	27,579,296	$ 296,471
Sales to employees	31,397	-
Exercise of stock options - net	68,548	285
Repurchase	(395,500)	(1,461)
Change to no-par common stock	-	(295,295)
Balance, Dec. 31, 2006	27,283,741	$ -
Sales to employees	21,373	n/a
Exercise of stock options - net	75,850	n/a
Repurchase	(973,616)	n/a
Balance, Dec. 31, 2007	26,407,348	$ -

4. STOCK-BASED COMPENSATION:

We have the following stock-based compensation plans: the Long-Term Incentive Plan (LTIP); the Restated Stock Option Plan (Restated SOP); the Employee Stock Purchase Plan (ESPP); and the 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 are purchased on the open market.

At December 31, 2007, 299,721 shares of common stock were available for award under the LTIP, assuming that outstanding performance based grants are awarded at the target level. The LTIP stock awards are compensatory awards for which compensation expense is recognized based on the market value of performance shares earned, or a pro rata amortization over the vesting period for the outstanding restricted stock awards.

Performance-based Stock Awards. Since the LTIP s inception in 2001 through December 31, 2007, performance-based stock awards have been granted annually based on three-year performance periods. At December 31, 2007, certain performance-based stock award

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measures had been achieved for the 2005-07 award period. Accordingly, participants are estimated to receive 66,666 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, 2006, certain performance-based stock award measures had been achieved for the 2004-06 award period and participants received 40,446 shares of common stock plus the applicable dividend equivalent cash payment, resulting in $0.8 million in cash for taxes or deferral into the deferred compensation plan. During 2007, we accrued and expensed $0.6 million related to the 2005-07 performance-based stock award, and on a cumulative basis we accrued a total $2.0 million related to the 2005-07 performance period. In 2006, we accrued and expensed $0.9 million related to the 2004-06 performance-based stock award, and on a cumulative basis we accrued a total of $1.7 million related to the 2004-06 performance period.

At December 31, 2007, 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
2006	2006-08	7,536	39,665	79,330
2007	2007-09	7,980	42,000	84,000
	Total	15,516	81,665	163,330

The threshold level estimates future payout assuming the minimum award payable other than no payout 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 SFAS No. 123R, 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, 2007 and 2006 was $25.45 and $30.65, respectively. The weighted-average per share grant date fair value of shares vested during the year was $44.95 and granted during the year was $31.32. In 2007, under these LTIP grants we accrued $2.7 million and expensed $2.3 million as compensation, while in 2006, we accrued and expensed $1.0 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 will vest ratably over the period 2005-09, and a restricted stock award was granted in 2006 consisting of 6,500 shares that will vest ratably over the period 2007-09. A total of 5,167 restricted stock award shares were vested at December 31, 2007. Compensation expense is recognized ratably over the vesting period.

Restated Stock Option Plan. The Restated SOP authorizes an aggregate of 2,400,000 shares of common stock for issuance as incentive or non-statutory stock options. These options 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 not less than the market value on the date of grant and may be exercised for a period not exceeding 10 years from the date of grant.

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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. We use original issue shares upon exercise of options under the plan. See Note 3.

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 six- to 12-month period. We use original issue shares upon exercise of options under the plan. See Note 3.

In accordance with APB Opinion No. 25, no compensation expense was recognized for options granted under the Restated SOP or shares issued under the ESPP during 2005 or earlier years. If compensation expense for awards under these two plans had been determined based on fair value at the grant dates using the method prescribed by SFAS No. 123R, net income and earnings per share would have been reduced to the pro forma amounts shown below:

Pro Forma Effect of Stock-Based Options and ESPP:

Thousands, except per share amounts	2005
Net income as reported	$ 58,149
Add: Stock-based compensation expense included in reported net income - net of related tax effects	613
Deduct: Pro forma stock-based compensation expense determined under the fair value based method - net of related tax effects	(940)
Pro forma earnings applicable to common stock	$ 57,822
Basic earnings per share	
As reported	$ 2.11
Pro forma	$ 2.10
Diluted earnings per share	
As reported	$ 2.11
Pro forma	$ 2.09

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:

	2007	2006	2005
Risk-free interest rate	4.7%	4.5%	4.2%
Expected life (in years)	6.2	6.2	7.0
Expected market price volatility factor	17.2%	22.8%	24.6%
Expected dividend yield	3.2%	4.0%	3.6%
Forfeiture rate	4%	3%	n/a
Weighted average grant date fair value	$7.66	$6.29	$7.85
Present value of options granted	$33.38	$26.00	$27.87

The simplified formula for plain vanilla options was utilized to determine the expected life as defined and permitted by Staff Accounting Bulletin No. 107. 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 employed in order to estimate the

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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 dividend payout 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 SFAS No. 123R and the retirement vesting provisions of our option agreements.

Information regarding the Restated SOP s activity for the three years ended December 31, 2007 is summarized as follows:

		Price per Share		
	Option Shares	Range	Weighted - Average Exercise Price	Intrinsic Value (In millions)
Balance outstanding, Dec. 31, 2004	431,470	$20.25 - 32.02	$ 28.38	n/a
Granted	9,000	34.95 - 38.30	37.18	n/a
Exercised	(121,170)	20.25 - 31.34	26.59	$ 1.2
Forfeited	(10,800)	27.60 - 31.34	30.79	n/a
Balance outstanding, Dec. 31, 2005	308,500	20.25 - 38.30	29.26	n/a
Granted	97,800	34.29	34.29	n/a
Exercised	(69,300)	20.25 - 31.34	27.15	0.8
Forfeited	(3,000)	31.34 - 34.29	32.52	n/a
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
Shares available for grant Dec. 31, 2005	1,229,800			
Shares available for grant Dec. 31, 2006	1,135,000			
Shares available for grant Dec. 31, 2007	1,035,400			

In the year ended December 31, 2007, cash of $2.7 million was received for option shares exercised and a $0.5 million related tax benefit was realized. The total fair value of options that vested was $0.2 million in 2007 and $0.4 million in both 2006 and 2005.

The following table summarizes additional information about stock options outstanding and exercisable at December 31, 2007:

	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
$20.25 - 44.48	357,750	7.35	193,675	$3.4	$31.15	6.2

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In accordance with SFAS No. 123R, stock-based compensation expense is recognized within operations and maintenance expense or is capitalized as part of construction overhead. The following table summarizes the allocations of stock-based compensation grants under our LTIP, SOP and ESPP:

Thousands	2007	2006
Operations and maintenance expense	$ 2,986	$ 2,304
Stock-based compensation effect on income before taxes	2,986	2,304
Income taxes	(1,165)	(898)
Net stock-based compensation effect on net income	$ 1,821	$ 1,406
Amounts capitalized	$ 479	$ 407

As of December 31, 2007, there was $0.6 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2010.

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 our 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 latter 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. During 2006, 7,848 shares vested under the plan and no forfeitures occurred. At December 31, 2007, 5,235 shares remain unvested, all of which are scheduled to vest by December 31, 2008. The weighted-average grant-date fair value of unvested shares at December 31, 2007 and 2006 was $30.60 and $28.92, respectively.

Under a separate plan, prior to January 1, 2005 non-employee directors could elect to invest their cash fees and retainers for board service in shares of common stock. Under a deferral plan effective January 1, 2005, such fees and retainers are deferred to a cash account. Cash account balances may be transferred to and invested in a stock account at the election of the director up to four times per year.

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5. LONG-TERM DEBT:

The issuance of first mortgage debt, including secured medium-term notes, under the Mortgage and Deed of Trust (Mortgage), is limited by property additions, 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, 2012 amount to: $5 million in 2008; none in 2009; $35 million in 2010; $10 million in 2011; and $40 million in 2012. Holders of certain long-term debt have put options that, if exercised, would accelerate the maturities by $20 million in both 2008 and 2009.

Thousands (December 31)	2007	2006	2005
Medium-Term Notes			
First Mortgage Bonds:			
6.05% Series B due 2006[1]	$ -	$ -	$ 8,000
6.31 % Series B due 2007[2]	-	20,000	20,000
6.80 % Series B due 2007[3]	-	9,500	9,500
6.50% Series B due 2008	5,000	5,000	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
4.70% Series B due 2015	40,000	40,000	40,000
5.15% Series B due 2016	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
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	20,000	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
	517,000	546,500	529,500
Less long-term debt due within one year	5,000	29,500	8,000
Total long-term debt	$ 512,000	$ 517,000	$ 521,500

[1] Redeemed at maturity in June 2006.

[2] Redeemed at maturity in March 2007.

(3) Redeemed at maturity in May 2007.

No long-term debt was issued during 2007. In 2006, we issued and sold $25 million of 5.15% Series B secured Medium Term Notes (MTNs) due 2016. Proceeds from this sale were used, in part, to repay short-term debt and fund our ongoing utility construction program.

In June 2005, we issued and sold $50 million of secured MTNs, consisting of $40 million of the 4.70% Series B secured MTNs due 2015 and $10 million of the 5.25% Series B secured MTNs due 2035. Proceeds from these sales were used, in part, to redeem $15 million of maturing MTNs in July 2005, and the balance was applied to our ongoing utility construction program and the repayment of short-term debt.

6. NOTES PAYABLE AND CREDIT FACILITIES:

Our primary source of short-term funds is from the sale of commercial paper notes payable. 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 is periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by a committed credit facility (see below). At December 31, 2007 and 2006, the amounts and average interest rates of commercial paper debt outstanding were $143.1 million and 4.4 percent and $100.1 million and 5.3 percent, respectively.

In May 2007, we entered into a credit agreement for unsecured revolving loans totaling $250 million, replacing the prior $200 million bilateral credit agreements which were terminated. The new credit facility is available and committed for a term of five years expiring on May 31, 2012, which may be extended for additional one-year periods thereafter subject to lender approval. The credit facility allows us to request increases in the total commitment amount, up to a maximum amount of $400 million. The credit facility also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. The credit facility continues to be used primarily as back-up credit support for the notes payable issued under our commercial paper program. Commercial paper borrowing provides the liquidity to meet our working capital and interim financing requirements. Under the terms of the credit facility, we pay upfront fees, annual commitment fees and administrative agent fees, but we are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under the credit agreement are based on our long-term unsecured debt ratings and on then-current market interest rates. All principal and unpaid interest under the credit facility is due and payable on May 31, 2012, subject to extensions if any. There were no outstanding balances on this credit facility at December 31, 2007 or on prior credit facilities at December 31, 2006.

The credit agreement requires that we maintain credit ratings with Standard & Poor s (S&P) and Moody s Investors Service, Inc. (Moody s) and notify the lenders of any change in our senior unsecured debt ratings by such rating agencies. A change in our debt ratings is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit facility. However, interest rates on any loans outstanding under the credit facility are tied to debt ratings, which would increase or decrease the cost of any loans under the credit facility when ratings are changed.

The credit facility 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 to accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2007, with an indebtedness to total capitalization ratio of 52.7 percent. Our previous credit agreements required us to maintain an indebtedness to total capitalization ratio of 65 percent or less, which we were in compliance with at December 31, 2006.

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 benefit plans for employees. 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, the Retirement Plan for Non-Bargaining Unit Employees and the Welfare Benefits Plan for Non-Bargaining Unit Employees were closed to anyone hired or rehired after December 31, 2006. Instead, newly hired or rehired non-bargaining unit employees will be provided an enhanced Retirement K Savings Plan (RKSP) benefit. Benefits provided to bargaining unit employees under the Retirement Plan for Bargaining Unit Employees are not affected by these changes.

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, 2007, and a summary of the funded status and amounts recognized in the consolidated balance sheets using measurement dates of December 31, 2007, 2006 and 2005:

	Postretirement Benefits					
	Pension Benefits			Other Benefits		
Thousands	2007	2006	2005	2007	2006	2005
Reconciliation of change in benefit obligation:						
Obligation at January 1	$ 269,410	$ 267,854	$ 222,948	$ 22,436	$ 20,398	$ 22,729
Service cost	8,708	7,745	6,322	505	555	767
Interest cost	16,057	14,901	13,203	1,293	1,184	1,248
Expected benefits paid	(15,924)	(13,183)	(12,866)	(1,299)	(1,015)	(1,173)
Plan amendments	3,887	-	1,408	-	15	2,384
Change in assumptions	(23,916)	(9,208)	31,642	(645)	133	2,215
Net actuarial (gain) or loss	2,339	1,301	5,197	(104)	1,166	(7,772)
Obligation at December 31	$ 260,561	$ 269,410	$ 267,854	$ 22,186	$ 22,436	$ 20,398
Reconciliation of change in plan assets:						
Fair value of plan assets at January 1	$ 236,518	$ 218,555	$ 186,787	$ -	$ -	$ -
Actual return on plan assets	19,658	30,088	12,558	-	-	-
Employer contributions	1,166	1,058	32,076	1,298	1,015	1,173
Benefits paid	(15,924)	(13,183)	(12,866)	(1,298)	(1,015)	(1,173)
Fair value of plan assets at December 31	$ 241,418	$ 236,518	$ 218,555	$ -	$ -	$ -
Funded status:						
Funded status at December 31	$ (19,143)	$ (32,892)	$ (49,299)	$ (22,186)	$ (22,436)	$ (20,398)
Unrecognized transition obligation	-	-	-	2,058	2,469	2,880
Unrecognized prior service cost	8,212	5,512	6,492	1,866	2,063	2,243
Unrecognized net actuarial loss	20,995	45,862	69,766	1,514	2,288	988
Net amount recognized	$ 10,064	$ 18,482	$ 26,959	$ (16,748)	$ (15,616)	$ (14,287)

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In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, which required balance sheet recognition of the overfunded or underfunded status of pension and other postretirement benefit plans. We adopted SFAS No. 158 effective December 31, 2006. For pension plans, the liability is based on the projected benefit obligation. Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in accumulated other comprehensive income (AOCI) under common stock equity, net of tax, until they are amortized as a component of net periodic benefit cost. We consider the recognition of the underfunded status of the qualified defined benefit plans and postretirement benefit plans to be subject to regulatory deferral under SFAS No. 71. The unrecognized net gains and losses, prior service costs and transition obligations relating to our qualified defined benefit pension and postretirement benefit plans are recognized as regulatory assets. An estimated $1.9 million for the qualified plans, consisting of $1.4 million of prior service costs, transition obligations of $0.4 million, and negligible actuarial gains, will be amortized from the regulatory asset account to net periodic benefit cost in 2008. The gains and losses, prior service costs and transition obligations related to our non-qualified supplemental pension plans are recognized in AOCI, net of tax, under common stock equity because these expenses are not the basis for regulatory recovery; however, these amounts are not material. In 2008, an estimated $0.4 million consisting of actuarial gains of $0.4 million and negligible prior service costs for the non-qualified plans will be amortized from AOCI to net periodic benefit cost.

Our qualified defined benefit pension plans had an aggregate projected benefit obligation of $243.1 million, $255.5 million and $254.4 million at December 31, 2007, 2006 and 2005, respectively, and the fair value of plan assets was $241.4 million, $236.5 million and $218.6 million, respectively. Changes in valuation assumptions impact our projected benefit obligations. The projected benefit obligations at December 31, 2007 decreased $23.9 million due to an increase in the discount rate assumptions and increased by $3.4 million due to an increase in the benefit payments for certain retirees. The projected benefit obligations at December 31, 2006 decreased by $9.3 million, reflecting the increase in the discount rate assumptions, and increased by $0.3 million, reflecting updates in retirement and withdrawal rates for actual experience. 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.

An assumed discount rate was determined independently for each pension plan and other postretirement benefit plan based on the Citigroup Above Median Curve (Citigroup curve) using high quality bonds (rated AA- or higher by Standard & Poor s or Aa3 or higher by Moody s Investors Service). The Citigroup 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 Policy and Performance Objectives for the qualified pension plan assets held in the Retirement Trust Fund were approved by the Company s retirement committee, which is composed of senior management employees. The policy sets 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.

Our pension plan asset allocation at December 31, 2007 and 2006, and the target allocation and expected long-term rate of return by asset category, are as follows:

	Percentage of Plan Assets Dec. 31,		Target	Expected Long-term
Asset Category	2007	2006	Allocation	Rate of Return
US Large Cap Equity	18.1%	19.2%	20%	8.50%
US Small/Mid Cap Equity	13.1%	13.9%	15%	9.50%
Non-US Equity	24.9%	23.5%	20%	8.75%
Fixed Income	13.3%	15.6%	15%	5.50%
Real Estate	8.9%	7.7%	8%	7.75%
Absolute Return Strategy	16.3%	14.3%	15%	9.00%
Real Return Strategy	5.4%	5.8%	7%	7.75%
Weighted Average				8.25%

Our non-qualified supplemental defined benefit pension plans benefit obligations were $17.5 million, $13.9 million and $13.5 million at December 31, 2007, 2006 and 2005, 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 the plans 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 $22.2 million, $22.4 million and $20.4 million at December 31, 2007, 2006 and 2005, 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 from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

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The following tables provide the components of net periodic benefit cost for the qualified and non-qualified pension and other postretirement benefit plans for the years ended December 31, 2007, 2006 and 2005 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
Thousands	2007	2006	2005	2007	2006	2005
Service cost	$ 8,708	$ 7,745	$ 6,322	$ 505	$ 556	$ 767
Interest cost	16,057	14,901	13,203	1,293	1,184	1,248
Expected return on plan assets	(18,490)	(17,611)	(14,449)	-	-	-
Amortization of transition obligations	-	-	-	411	411	411
Amortization of prior service costs	1,188	979	1,077	197	195	142
Amortization of net loss	2,123	3,520	2,082	25	1	173
Net periodic benefit cost	$ 9,586	$ 9,534	$ 8,235	$ 2,431	$ 2,347	$ 2,741
Assumptions for net periodic benefit cost:						
Discount rate	6.0%-6.05%	5.75%	6.00%	5.91%	5.75%	6.00%
Rate of increase in compensation	4.0%-5.0%	4.0%-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:						
Discount rate	6.76%-6.87%	6.0%-6.05%	5.75%	6.56%	5.91%	5.75%
Rate of increase in compensation	4.0%-5.0%	4.0%-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, 2007 were 8 percent for medical and 11 percent for prescription drugs. Medical costs were assumed to decrease gradually each year to a rate of 4.50 percent by 2013, while prescription drug costs were assumed to decrease gradually each year to a rate of 4.50 percent by 2014.

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	$ 26	$ (23)
Effect on health care cost component of the accumulated postretirement benefit obligation	$ 277	$ (250)

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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, 2007 and 2006, and estimated future payments:

Thousands		
Employer Contributions by Plan Year	Pension Benefits	Other Benefits
2006	$ 1,527	$ 1,015
2007	1,606	1,298
2008 (estimated)	1,703	1,794
Benefit Payments		
2005	$ 12,866	$ 1,173
2006	13,183	1,015
2007	15,924	1,298
Estimated Future Payments		
2008	$ 14,809	$ 1,794
2009	15,522	1,823
2010	16,623	1,887
2011	17,085	1,978
2012	17,897	1,960
2013-2017	100,776	10,183

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 $1.9 million in 2007, $1.8 million in 2006, and $1.7 million in 2005. 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 totaled $0.4 million in 2007 and $0.5 million in both 2006 and 2005.

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8. INCOME TAXES:

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

Thousands, except percentages	2007	2006	2005
Income taxes at federal statutory rate	$41,495	$34,877	$31,804
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,566	3,655	2,913
Federal income tax credits	-	-	(210)
Amortization of investment and energy tax credits	(881)	(994)	(956)
Differences required to be flowed-through by regulatory commissions	(704)	(704)	(704)
Gains on company and trust-owned life insurance	(679)	(913)	(650)
Other - net	244	155	187
Reversal of amounts provided in prior years	19	158	336
Total provision for income taxes	$44,060	$36,234	$32,720
Federal statutory tax rate	35.0%	35.0%	35.0%
Increase (decrease):			
Current state income tax, net of federal tax benefit	3.9%	3.7%	3.2%
Federal income tax credits	0.0%	0.0%	-0.2%
Amortization of investment and energy tax credits	-0.7%	-1.0%	-1.1%
Differences required to be flowed-through by regulatory commissions	-0.6%	-0.7%	-0.8%
Gains on company and trust-owned life insurance	-0.6%	-0.9%	-0.7%
Other - net	0.2%	0.2%	0.2%
Reversal of amounts provided in prior years	0.0%	0.1%	0.4%
Effective tax rate	37.2%	36.4%	36.0%

The provision for income taxes consists of the following:

Thousands	2007	2006	2005
Current tax expense	$ 48,850	$ 52,621	$ 23,034
Deferred tax expense (benefit)	(3,909)	(15,393)	10,642
Deferred investment and energy tax credits	(881)	(994)	(956)
Total provision for income taxes	$ 44,060	$ 36,234	$ 32,720
Total income taxes paid	$56,215	$31,270	$28,479

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

Thousands	2007	2006	2005
Regulated utility:			
Federal			
Current	$ 36,805	$ 40,979	$ 17,848
Deferred	(3,287)	(12,472)	8,691
Deferred investment and energy tax credits	(713)	(756)	(784)
	32,805	27,751	25,755
State			
Current	6,782	7,490	1,649
Deferred	(569)	(2,338)	2,855
	6,213	5,152	4,504
Total charged to regulated utility	39,018	32,903	30,259
Non-regulated business segments:			
Federal			
Current	4,281	3,806	3,581
Deferred	61	(714)	(1,189)
Deferred investment and energy tax credits	(168)	(238)	(172)
	4,174	2,854	2,220
State			
Current	982	346	(44)
Deferred	(114)	131	285
	868	477	241
Total charged to non-regulated business segments	5,042	3,331	2,461
Total provision for income taxes	$ 44,060	$ 36,234	$ 32,720

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

Thousands	2007	2006
Deferred tax liabilities (assets)		
Utility plant and equipment	$ 155,832	$ 150,648
Regulatory Adjustment for Income Taxes Paid	2,356	-
Utility other deferred tax differences	477	-
Non-regulated deferred tax differences	3,923	3,893
Deferred tax liabilities	162,588	154,541

Utility regulatory balances	(25,973)	(10,039)
Utility other deferred tax differences	-	(4,053)
Deferred tax assets	(25,973)	(14,092)
Deferred tax liabilities - net	136,615	140,449
Regulatory income tax assets	68,649	67,141
Change in employee post retirement benefit plan liability	(2,118)	(1,413)
Deferred income taxes	203,146	206,177
Deferred investment tax credits	3,194	3,907
Deferred income taxes and investment tax credits	$ 206,340	$ 210,084

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We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2007.

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

Thousands	2007
Deferred tax expense (benefit), above	$ (3,909)
Increase in differences required to be flowed-through	1,508
Decrease in minimum pension liability included in AOCI	(705)
Decrease in deferred taxes associated with asset held for sale	243
Decrease in deferred investment tax credits	(881)
Change in deferred income tax accounts	$ (3,744)

We calculate our deferred tax assets and liabilities under SFAS No. 109, which requires recording deferred tax balances, at the currently enacted tax rate, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. 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.

The Internal Revenue Service (IRS) completed its audit of our consolidated income tax returns for the years 2002-2004 in the second quarter of 2006. The focus of the examination was the $35.8 million net operating loss (NOL) generated in 2004 and carried back to 2002. This loss was primarily due to the deductions claimed for a pension contribution and accelerated depreciation. A federal refund of $8.3 million was received in October 2005. In conjunction with recording the refund, we recorded additional federal and state income tax credits of $4.2 million. In addition to the NOL, the IRS examined income tax positions taken with respect to various other ordinary business transactions. We reached agreement with the IRS for certain income tax positions such that a notice of proposed adjustment was issued. As a result of this agreement, we recorded an income tax benefit of $0.1 million in 2006.

9. PROPERTY AND INVESTMENTS:

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

	2007		2006	
Thousands, except percentages	Amount	Weighted Average Depreciation Rate	Amount	Weighted Average Depreciation Rate
Transmission and distribution	$ 1,735,934	3.3%	$ 1,657,466	3.3%
Utility storage	112,984	2.6%	110,721	2.6%
General	96,612	3.0%	92,946	2.6%
Intangible and other	71,044	8.8%	68,088	8.6%
Gas stored long-term	14,232	0.0%	12,850	0.0%
Utility plant in service	2,030,806	3.4%	1,942,071	3.4%
Construction work in progress	21,355		21,427	
Total utility plant	2,052,161		1,963,498	
Accumulated depreciation	(615,533)		(574,093)	
Utility plant-net	$ 1,436,628		$ 1,389,405	

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Accumulated depreciation does not include $204.9 million and $187.4 million at December 31, 2007 and 2006, respectively, which represent accrued asset removal costs 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	2007 Amount	2007 Weighted Average Depreciation Rate	2006 Amount	2006 Weighted Average Depreciation Rate
Non-utility storage	$ 54,083		$ 34,652	
Other	4,881		4,820	
Non-utility plant in service	58,964	2.1%	39,472	2.5%
Construction work in progress	8,185		3,180	
Total non-utility plant	67,149		42,652	
Less accumulated depreciation	(7,904)		(6,916)	
Non-utility plant - net	$ 59,245		$ 35,736	

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

Thousands	2007	2006
Life insurance cash surrender value	$ 46,294	$ 45,234
Note receivable	518	526
Gas pipelines and other	7,258	1,369
Electric generation	-	856
Total other investments	$ 54,070	$ 47,985

Life Insurance Cash Surrender Value. We have invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term employee benefit plan liabilities.

Gas Pipelines. 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 entered into an agreement with TransCanada s Gas Transmission Northwest (GTN) for the purpose of developing, designing, permitting, constructing and owning a pipeline that would connect GTN s interstate transmission line to our local gas distribution system to serve markets in Oregon and the western United States (Palomar Pipeline). During 2007, we incurred expenses totaling $6.0 million related to planning and permitting.

Electric Generation. In 2007, Financial Corporation sold its ownership interests in wind power electric generation projects located in California (see Note 2).

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FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities, provides guidance for determining whether consolidation is required for entities over which control is achieved through means other than voting rights, known as variable interest entities. We currently do not have any significant interests in variable interest entities for which we are the primary beneficiary.

10 FAIR VALUE OF FINANCIAL INSTRUMENTS:

The estimated fair value of NW Natural s financial instruments has been determined using available market information and appropriate valuation methodologies. The following are financial instruments whose carrying values are sensitive to market conditions:

	Dec. 31, 2007		Dec. 31, 2006	
Thousands	Carrying Amount	Estimated Fair Value*	Carrying Amount	Estimated Fair Value
Long-term debt including amount due within one year	$ 517,000	$ 557,916	$ 546,500	$ 595,564

* This estimate is calculated net of commission fees

Fair value of the long-term debt was estimated using market prices in effect on the valuation date. Interest rates for debt with similar terms and remaining maturities were used to estimate fair value for long-term debt issues.

11. USE OF FINANCIAL DERIVATIVES:

We have entered into commodity swaps, an interest rate swap, 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 SFAS No. 133. We primarily utilize derivative financial instruments to manage commodity prices related to natural gas supply requirements and to hedge interest rate risk related to our 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 the PGA filing receive SFAS No. 71 regulatory deferral treatment. Derivatives contracts entered into for core utility customer requirements after the annual PGA rate has been set are subject to the PGA incentive sharing mechanism, whereby 67 percent of the changes in fair value are deferred as regulatory assets or liabilities and the remaining 33 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. Our interest rate swap qualifies for hedge accounting under SFAS No. 133. During the fourth quarter of 2006, we entered into a number of commodity-based financial derivatives after our PGA filing. The unrealized mark-to-market losses on these hedges subject to sharing were $2.9 million, which was recorded as a loss in 2006 and reversed in 2007.

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

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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 but are subject to a regulatory deferral tariff and, as such, are recorded as a derivative asset or liability. These forward contracts qualify for cash flow hedge accounting treatment under SFAS No. 133. The mark-to-market adjustment at December 31, 2007 was an unrealized gain of $0.1 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.

In 2007, we entered into a 10-year, $50 million fixed-price forward starting interest rate swap contract to hedge the interest rate exposure related to the forecasted issuance of long-term debt. This interest rate swap is an effective cash flow hedge under SFAS No. 133. We did not use any derivative instruments to hedge interest rates in 2006 or 2005.

The unrealized mark-to-market value at December 31, 2007 for all derivative contracts outstanding was a total loss of $15.4 million consisting of the following unrealized losses: $10.7 million on commodity-based financial swap contracts, $2.1 million on commodity-based financial option contracts, $1.4 million on commodity physical supply contracts and $1.3 million on an interest rate swap contract. These unrealized losses were offset in part by an unrealized gain of $0.1 million on foreign exchange forward contracts.

At December 31, 2007 and 2006, the unrealized gains or losses from mark-to-market valuations of our derivative instruments were primarily reported as regulatory liabilities or regulatory assets because the realized gains or losses at settlement are either included, or are expected to be included, in utility rates pursuant to regulatory deferral mechanisms. The estimated fair values of unrealized gains and losses on derivative instruments outstanding, determined using a discounted cash flow model for swaps and a Black-Scholes model for options, were as follows:

	Fair Value Gains (Losses)			
Thousands	Dec. 31, 2007		Dec. 31, 2006	
	Current	Non-Current	Current	Non-Current
Natural gas commodity-based derivative instruments:				
Natural gas commodity hedge contracts	$ (12,099)	$ (2,104)	$ (33,528)	$ (9,583)
Interest rate hedge contract	-	(1,330)	-	-
Foreign currency forward purchase contracts	173	-	(135)	-
Total	$ (11,926)	$ (3,434)	$ (33,663)	$ (9,583)

In 2007 and 2006, we realized net losses of $42.0 million and $20.0 million, respectively, from the settlement of fixed-price financial swap contracts which were recorded as increases to the cost of gas. Net realized gains from the settlement of such contracts in 2005 were $88.9 million and were recorded as decreases to the cost of gas. Realized losses in 2007 were offset by lower gas purchase costs from the underlying hedged floating rate physical supply contracts. The currency exchange rate in all foreign currency forward purchase contracts is included in our cost of gas at settlement; therefore, no gain or loss was recorded from the settlement of those contracts. Any change in value of cash flow hedge contracts that is not included in regulatory recovery is included in other comprehensive income. There were no realized gains or losses on the interest rate swap during 2007.

As of December 31, 2007, all of the natural gas hedges mature by or are extendible to October 31, 2009. The maturity date for our interest rate swap contract is September 30, 2018; however, we expect to cash settle this contract concurrently with the issuance of long-term debt in the second half of 2008.

12. COMMITMENTS AND CONTINGENCIES:

Lease Commitments

We lease land, buildings and equipment under agreements that expire in various years through 2046. Rental expense under operating leases was $4.6 million, $4.4 million and $4.1 million for the years ended December 31, 2007, 2006 and 2005, respectively. The table below reflects the future minimum lease payments due under non-cancelable leases at December 31, 2007. Such payments total $53.0 million for operating leases. The net present value of payments on capital leases less imputed interest was $1.2 million. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, vehicles and computer equipment.

Thousands	2008	2009	2010	2011	2012	Later years
Operating leases	$ 4,257	$ 4,184	$ 4,177	$ 4,140	$ 4,265	$ 32,003
Capital leases	532	393	255	26	-	-
Minimum lease payments	$ 4,789	$ 4,577	$ 4,432	$ 4,166	$ 4,265	$ 32,003

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 gas purchase agreements. The aggregate amounts of these agreements were as follows at December 31, 2007:

Thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2008	$ 302,709	$ 87,453	$ 5,105
2009	118,936	68,631	5,105
2010	53,253	65,344	4,254
2011	24,106	64,989	-
2012	24,106	49,977	-
2013 through 2027	44,193	131,501	-
Total	567,303	467,895	14,464
Less: Amount representing interest	27,538	61,410	567
Total at present value	$ 539,765	$ 406,485	$ 13,897

Our total payments of fixed charges under capacity purchase agreements in 2007, 2006 and 2005 were $90.1 million, $69.2 million and $83.1 million, respectively. Included in the

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amounts were reductions for capacity release sales of $5.3 million for 2007 and $3.7 million for both 2006 and 2005. 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 have 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. 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. During 2007, we accrued an additional $19.3 million

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for estimated liabilities based on updated information for the development of proposed studies of in-water source control and completion of remedial actions. We have a net liability of $21.2 million at December 31, 2007 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 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 working with the ODEQ to develop a study of manufactured gas plant wastes on the uplands at this site. During 2007, the estimated liability for this site increased by $1.8 million related to future expenditures in connection with the study, which is at the low end of the range of potential additional liability because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated. The net liability at December 31, 2007 for the Siltronic site is $1.5 million.

Portland Harbor site. In 1998, the ODEQ and the U.S. Environmental Protection Agency (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 site and the Siltronic site. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties, referred to as the Lower Willamette Group, to fund environmental studies in the Portland Harbor. 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 2009. The EPA and the Lower Willamette Group are conducting focused studies on approximately nine miles of the lower Willamette River, including the segment previously studied by the EPA. During 2007, we received a revised estimate and following a review of that estimate, we accrued an additional $13.6 million for additional expenditures related to RI/FS development and environmental remediation and monitoring after the RI/FS work plan is completed. As of December 31, 2007, we have a net liability of $13.8 million, 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 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, and legal fees and ongoing monitoring, was about $10.4 million. In 2007 we accrued $0.5 million for additional monitoring and reporting expense. To date, we have paid $9.8 million on work related to the removal of the tar deposit. As of December 31, 2007, we have a net liability of $1.0 million, 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 be estimated.

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

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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 has been 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. During 2007, we accrued $0.5 million for estimated liabilities related to the design of an investigational plan for this site in cooperation with the ODEQ. We cannot estimate a range of liability until studies are completed.

Front Street site. The Front Street site was the former location of a gas manufacturing plant operated by our predecessor. 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 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. Until the results of that sampling are evaluated, a future cost cannot be reasonably estimated.

Oregon Steel Mills site. See Legal Proceedings, below.

Accrued Liabilities relating to Environmental sites. Until the current year, we had not been able to determine the timing of our environmental liabilities and therefore had classified no liabilities as current prior to June 2007. The following table summarizes the accrued liabilities relating to environmental sites at December 31, 2007 and 2006:

	Current Liabilities		Non-Current Liabilities	
Thousands	2007	2006	2007	2006
Gasco site	$ 6,901	$ -	$ 14,342	$ 6,414
Siltronic site	-	-	1,540	43
Portland Harbor site	-	-	14,821	2,149
Central Service Center site	-	-	529	-
Other sites	-	-	167	62
Total	$ 6,901	$ -	$ 31,399	$ 8,668

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the OPUC approved our request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic, Portland Harbor and Front Street sites. The authorization, which was extended through January 2008 and expanded to include the Oregon Steel Mills site, allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. Beginning in 2006, the OPUC authorized us to accrue interest on deferred 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. An application for further extension of the regulatory approval to defer environmental costs and accrued interest is pending. As of December 31, 2007, we have paid a cumulative total of $24.8 million relating to the named sites since the effective date of the deferral authorization.

On a cumulative basis, we have recognized a total of $67.8 million for environmental costs, including legal, investigation, and monitoring and remediation costs. Of this total, $29.5 million has been spent to-date and $38.3 million is reported as an outstanding liability. At December 31, 2007, we had a regulatory asset of $63.1 million which includes $24.8 million of total paid expenditures to date, $35.1 million for additional environmental accruals for costs expected to be paid in the future and accrued interest of $3.2 million. We believe the recovery

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of these costs is probable through the regulatory process. We intend to pursue recovery of these environmental costs from 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 some portion 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 legislation 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 but continue to anticipate that our overall insurance recovery effort will extend over several years.

We anticipate that our regulatory recovery of environmental cost deferrals will not be initiated within the next 12 months because we will not have completed our insurance recovery efforts during that time period. As such we have classified our regulatory assets for environmental cost deferrals as non-current. The following table summarizes the regulatory assets and accrued liabilities relating to environmental matters at December 31, 2007 and 2006:

	Non-Current Regulatory Assets	
Thousands	2007	2006
Gasco site	$ 29,042	$ 10,336
Siltronic site	2,227	477
Portland Harbor site	30,869	16,769
Central Service Center site	545	-
Other sites	371	291
Total	$ 63,054	$ 27,873

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 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 Port s 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. In March 2005, motions to dismiss by ourselves and other third-party defendants were denied on the basis that the failure of the Port to plead and prove that we were in violation of law was an affirmative defense that may be asserted at trial, but did not provide a sufficient basis for dismissal of the Port s claim. 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.

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NORTHWEST NATURAL GAS COMPANY

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Quarter ended				
Thousands, except per share amounts	March 31	June 30	Sept. 30	Dec. 31	Total
2007					
Operating revenues	$ 394,091	$ 183,249	$ 124,245	$ 331,608	$ 1,033,193
Net operating revenues	139,008	64,118	49,663	116,253	369,042
Net income (loss)	48,075	2,617	(5,908)	29,713	74,497
Basic earnings (loss) per share	1.77	0.10	(0.22)	1.12	2.78*
Diluted earnings (loss) per share	1.76	0.10	(0.22)	1.11	2.76*
2006					
Operating revenues	$ 390,391	$ 170,979	$ 114,914	$ 336,888	$ 1,013,172
Net operating revenues	125,464	61,747	41,341	111,624	340,176
Net income (loss)	41,033	1,994	(9,724)	30,112	63,415
Basic earnings (loss) per share	1.49	0.07	(0.35)	1.10	2.30*
Diluted earnings (loss) per share	1.48	0.07	(0.35)	1.09	2.29*

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

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NORTHWEST NATURAL GAS COMPANY

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B Balance at beginning of period	COLUMN C Additions Charged to costs and expenses	COLUMN C Additions Charged to other accounts	COLUMN D Deductions Net Write-offs	COLUMN E Balance at end of period
Thousands (year ended Dec. 31)					
2007					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 3,033	$ 2,978	$ 0	$ 3,121	$ 2,890
2006					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 3,067	$ 3,036	$ 0	$ 3,070	$ 3,033
2005					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,434	$ 3,034	$ 0	$ 2,401	$ 3,067

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As of December 31, 2007, the principal executive officer and principal financial officer of Northwest Natural Gas Company (NW Natural) have evaluated 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). Based upon that evaluation, the principal executive officer and principal financial officer of NW Natural have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by us and included in our reports filed with the Securities and Exchange Commission (Commission) under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Commission s rules and forms and are also effective to ensure that information required to be disclosed by us and included in our reports filed with or furnished to the Commission under the Exchange Act is accumulated and communicated to our management 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 our most recent fiscal quarter 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

(a) Entry into a Material Service Agreement

On February 8, 2008, we entered into a service agreement with Northwest Pipeline GP, for an additional 120,000 therms per day of firm transportation capacity form the U.S. Rocky Mountain region upon assignment of the capacity from March Point Cogeneration Company. The primary term of the transportation service agreement will begin on January 1, 2017 and end on December 31, 2046.

This contract is included as Exhibit 10j.(9).

(b) Entry into Service Agreement Amendment

On February 12, 2008, we entered into a service agreement amendment with Northwest Pipeline GP to extend the primary term of the previous agreement, dated June 29, 1990, to September 30, 2044. The amendment also provides an additional 351,550 therms per day of firm transportation capacity from the U.S. Rocky Mountain region.

This contract is included as Exhibit 10j.(7).

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning our Board of Directors, its Committees and the Audit Committee financial expert contained in NW Natural s definitive Proxy Statement for the May 22, 2008 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 22, 2008 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2007	Positions held during last five years
Mark S. Dodson	62	Chief Executive Officer (2007-); President and Chief Executive Officer (2003-2007).
Gregg S. Kantor	50	President and Chief Operating Officer (2007 -); Executive Vice President (2006 -2007); Senior Vice President, Public and Regulatory Affairs (2003-2006).
David H. Anderson	46	Senior Vice President and Chief Financial Officer (2004-); Senior Vice President and Chief Financial Officer, TXU Gas Company (2004); Senior Vice President, Principal Accounting Officer and Controller (2003-2004); Vice President of Investor Relations and Shareholder Services, TXU Corp. (1997-2003).
Margaret D. Kirkpatrick	53	Vice President and General Counsel (2005-); Partner, Stoel Rives LLP (1991-2005).
Lea Anne Doolittle	52	Vice President, Human Resources (2000-).
J. Keith White	54	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); Director, Strategic Development (2003); Director, Corporate and Business Development (2001-2003).
David R. Williams	54	Vice President, Utility Services (2007-); Director, Acquire Customers (2006); Director, Gas Operations (2005-2006); General Manager, Utility Operations (1999-2004)
Grant M. Yoshihara	52	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); General Manager, Consumer Services (2003-2004).
Stephen P. Feltz	52	Treasurer and Controller (1999-).
C. J. Rue	62	Secretary (1982-2007); Assistant Treasurer (1987-2007).
Richelle T. Luther	39	Assistant Secretary (2002-).

Each executive officer serves successive annual terms; present terms end on May 22, 2008. There are no family relationships among our executive officers.

NW Natural has adopted a Code of Ethics for 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.

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 22, 2008 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2007 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, 2007 (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]	87,998	n/a	299,721
Restated Stock Option Plan	357,750	$ 35.36	1,035,400
Employee Stock Purchase Plan	23,213	$ 40.95	199,820
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)[2]	6,967	n/a	n/a
Directors Deferred Compensation Plan (DDCP)[2]	74,580	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)[3]	27,024	n/a	n/a
Non-Employee Directors Stock Compensation Plan[4]	n/a	n/a	n/a
Total	577,532		1,534,941

The information captioned Beneficial Ownership of Common Stock by Directors and Executive Officers contained in our definitive Proxy Statement for the May 22, 2008 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 by us when the award criteria are satisfied. If the maximum awards were paid pursuant to the performance-based awards outstanding at December 31, 2007, the number of shares shown in column (a) would increase by 81,665 shares and the number of shares shown in column (c) would decrease by 81,665 shares.

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

[3] Effective January 1, 2005, the EDCP and DDCP were 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 ten years as elected by the participant in accordance with the terms of the DCP. The right of each participant in the DCP is that of a general, unsecured creditor of the Company.

[4] The material features of this plan are more particularly described in Note 4 to the Consolidated Financial Statements included in this report.

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 22, 2008 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned 2007 and 2006 Audit Firm Fees in the Company s definitive Proxy Statement for the May 22, 2008 Annual Meeting of Shareholders is hereby incorporated by reference.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

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

2. List of Exhibits filed:

Reference is made to the Exhibit Index commencing on page 115.

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SIGNATURES

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

	NORTHWEST NATURAL GAS COMPANY
Date: February 29, 2008	By: /s/ Mark S. Dodson Mark S. Dodson, 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/ Mark S. Dodson Mark S. Dodson, Chief Executive Officer	Principal Executive Officer and Director		February 29, 2008
/s/ David H. Anderson David H. Anderson Senior Vice President and Chief Financial Officer	Principal Financial Officer		February 29, 2008
/s/ Stephen P. Feltz Stephen P. Feltz Treasurer and Controller	Principal Accounting Officer		February 29, 2008
/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/ C. Scott Gibson C. Scott Gibson	Director	))	
/s/ Tod R. Hamachek Tod R. Hamachek	Director	))	
/s/ Randall C. Papé Randall C. Papé	Director	))	February 29, 2008
/s/ Jane L. Peverett Jane L. Peverett	Director	))	
/s/ George J. Puentes George J. Puentes	Director	))	
/s/ Richard G. Reiten Richard G. Reiten	Director	))	

/s/ Kenneth Thrasher	Director	)
Kenneth Thrasher		)
/s/ Russell F. Tromley	Director	)
Russell F. Tromley		)

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EXHIBIT INDEX

To

Annual Report on Form 10-K

For Fiscal Year Ended

December 31, 2007

Exhibit Number	Document
*3a.	Restated Articles of Incorporation, as filed and effective May 31, 2006 and amended May 31, 2006 (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).
*4d.	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).
*4e.	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).
*4f.	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).
*4f.(1)	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).

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*4i.	Form of Credit Agreement between Northwest Natural Gas Company and each of JPMorgan Chase Bank, N.A., and Bank of America, N.A., 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).
*4j.	Distribution Agreement, dated September 28, 2004 as amended and restated on December 7, 2006, among the Company, Merrill Lynch, Pierce Fenner & Smith Incorporated, UBS Securities LLC, J.P. Morgan Securities Inc. and Piper Jaffray & Co (incorporated herein by reference to Exhibit 4j. to Form 10-K for 2006, File No. 1-15973).
*4k.	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).
*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).
*10j.	Transportation Agreement, dated June 29, 1990, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j. to Form 10-K for 1993, File No. 0-994).
*10j.(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).
*10j.(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).
*10j.(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).
*10j.(5)	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).
*10j.(6)	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).
10j.(7)	Service Agreement Amendment, dated February 12, 2008, between the Company and Northwest Pipeline GP.
10j.(8)	Service Agreement, dated February 8, 2008, between the Company and Northwest Pipeline GP.
10j.(9)	Agreement between the Company and March Point Cogeneration Company, dated February 8, 2008.
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 (2007 Restatement).
10b.(1)	Supplemental Executive Retirement Plan, effective September 1, 2004 restated December 20, 2007.
*10b.(2)	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).
*10b.(3)	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).
*10b.(4)	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).
*10c.	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).
*10c.(1)	Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10.3 to Form 10-Q dated November 3, 2005, File No. 1-15973).
10e.	Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of February 28, 2008.
10f.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 28, 2008.
10f.(1)	Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated February 28, 2008.
*10g.	Form of Indemnity Agreement as entered into between the Company and each director and executive officer (incorporated herein by reference to Exhibit 10g. to Form 10-K for 1988, File No. 0-994).
*10i.	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).

*10k.	Executive Annual Incentive Plan, effective January 1, 2003
	(incorporated herein by reference to Exhibit 10 k. to Form 10-K for 2002, File No. 0-994)
*10o.	Form of amended and restated executive change in control severance agreement between the Company and each executive officer other than Mark S. Dodson (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10o.-1	Amended and restated executive change in control severance agreement dated December 14, 2006 between the Company and Mark S. Dodson (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10p.	Employment Agreement dated July 2, 1997, between the Company and an executive officer (incorporated herein by reference to Exhibit 10(a) for Form 10-Q for the quarter ended September 30, 1997, File No. 0-994).
*10p.-1	Amendment dated December 18, 1997 to employment agreement dated July 2, 1997, between the Company and an executive officer (incorporated herein by reference to Exhibit 10p.-1 to Form 10-K for 1997, File No. 0-994).
*10p.-2	Amendment dated September 24, 1998 to employment agreement dated July 2, 1997, as previously amended, between the Company and an executive officer (incorporated herein by reference to Exhibit 10(g) to Form 10-Q for the quarter ended September 30, 1998, File No. 0-994).
*10p.-3	Employment Agreement dated December 20, 2002, between the Company and an executive officer (incorporated herein by reference to Exhibit 10p.-3 to Form 10-K for 2002, File No. 0-994).
*10p.-4	Amendment dated December 14, 2006 to employment agreement dated December 20, 2002 between the Company and Mark S. Dodson (incorporated herein by reference to Exhibit 10.8 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10v.	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).
*10w.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.8 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10w.(1)	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).
10w.(2)	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan.

*10x.	Form of Restricted Stock Bonus Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10x.(1)	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).
*10z.(1)	Summary of non-employee director compensation, effective January 1, 2007 (incorporated herein by reference to Form 8-K dated October 3, 2006, File No. 1-15973).
*10aa.	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).
10bb.	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 as indicated