RANGE RESOURCES CORP
Form 10-K
February 25, 2009

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark one)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

OR

o **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: 001-12209

RANGE RESOURCES CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**34-1312571**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
100 Throckmorton Street, Suite 1200, Fort Worth, Texas	**76102**
(Address of Principal Executive Offices)	(Zip Code)

Registrant s telephone number, including area code
(817) 870-2601
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, $.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant as a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes o No þ

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 þ No o

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. o

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o (Do not check if a smaller reporting company) Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in 12b-2 of the Act). Yes o No þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2008 was $9,963,751,000. This amount is based on the closing price of registrant s common stock on the New York Stock Exchange on that date. Shares of common stock held by executive officers and directors of the registrant are not included in the computation. However, the registrant has made no determination that such individuals are affiliates within the meaning of Rule 405 of the Securities Act of 1933.

As of February 19, 2009, there were 156,206,315 shares of Range Resources Corporation Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s proxy statement to be furnished to stockholders in connection with its 2009 Annual Meeting of Stockholders are incorporated by reference in Part III, Items 10-14 of this report.

RANGE RESOURCES CORPORATION

Unless the context otherwise indicates, all references in this report to Range, we, us or our are to Range Resources Corporation and its wholly-owned subsidiaries and its ownership interests in equity method investees. Unless otherwise noted, all information in the report relating to oil and gas reserves and the estimated future net cash flows attributable to those reserves are based on estimates and are net to our interest. If you are not familiar with the oil and gas terms used in this report, please refer to the explanation of such terms under the caption Glossary of Certain Defined Terms at the end of Item 15 of this report.

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RANGE RESOURCES CORPORATION
Annual Report on Form 10-K
Year Ended December 31, 2008

Disclosures Regarding Forward-Looking Statements

Certain information included in this report, other materials filed or to be filed with the Securities and Exchange Commission (the SEC), as well as information included in oral statements or other written statements made or to be made by us, contain or incorporate by reference certain statements (other than statements of historical fact) that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. When used herein, the words budget, budgeted, assumes, shoul goal, anticipates, expects, believes, seeks, plans, estimates, intends, projects or targets and similar convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based on the best data available at the date this report is filed with the SEC, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, the following: the factors listed in Item 1A of this report under the heading Risk Factors, production variance from expectations, volatility of oil and gas prices, hedging results, the need to develop and replace reserves, the substantial capital expenditures required to fund operations, exploration risks, environmental risks, uncertainties about estimates of reserves, competition, litigation, government regulation, political risks, our ability to implement our business strategy, costs and results of drilling new projects, mechanical and other inherent risks associated with oil and gas production, weather, availability of drilling equipment and changes in interest rates. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph, and we undertake no obligation to publicly update or revise any forward-looking statements.

PART I

ITEM 1. BUSINESS

General

We are a Fort Worth, Texas-based independent oil and gas company, engaged in the exploration, development and acquisition of oil and gas properties, primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We were incorporated in 1980 under the name Lomak Petroleum, Inc. and, later that year, we completed an initial public offering and began trading on the NASDAQ. In 1996, our common stock was listed on the New York Stock Exchange. In 1998, we changed our name to Range Resources Corporation. In 1999, we implemented a strategy of internally generated drillbit growth coupled with complementary acquisitions. Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. During the past five years, we have increased our proved reserves 288% (from 684.5 Bcfe in 2003 to 2.654 Tcfe in 2008), while production has increased 143% (from 58,053 Mmcfe in 2003 to 141,145 Mmcfe in 2008) during that same period.

At year-end 2008, our proved reserves had the following characteristics:

- 2.7 Tcfe of proved reserves;
- 83% natural gas;
- 62% proved developed;
- 77% operated;

a reserve life of 17.9 years (based on fourth quarter 2008 production);

a pre-tax present value of $3.4 billion of future net cash flows attributable to our reserves, discounted at 10% per annum (PV-10); and

a standardized after-tax measure of discounted future net cash flows of $2.6 billion.

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PV-10 may be considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after-tax amount, because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is discounted estimated future income tax of $819.0 million at December 31, 2008.

At year-end 2008, we owned 3,694,000 gross (2,952,000 net) acres of leasehold, including 407,800 acres where we also own the royalty interest. We have built a multi-year drilling inventory that is estimated to contain over 12,000 drilling locations.

Our corporate offices are located at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. Our telephone number is (817)
870-2601.

Business Strategy

Our objective is to build stockholder value through consistent growth in reserves and production on a cost-efficient basis. Our strategy is to employ internally generated drillbit growth coupled with complementary acquisitions. Our strategy requires us to make significant investments in technical staff, acreage and seismic data and technology to build drilling inventory. Our strategy has the following principal elements:

Concentrate in Core Operating Areas. We currently operate in three regions: the Southwestern (which includes the Barnett Shale of North Central Texas, the Permian Basin of West Texas and eastern New Mexico, the East Texas Basin, the Texas Panhandle and the Anadarko Basin of Western Oklahoma), Appalachian (which includes tight-gas, shale, coal bed methane and conventional oil and gas production in Pennsylvania, Virginia, Ohio, New York and West Virginia) and the Gulf Coast (which includes Texas, Louisiana and Mississippi). Concentrating our drilling and producing activities in these core areas allows us to develop the regional expertise needed to interpret specific geological and operating trends and develop economies of scale. Operating in multiple core areas allows us to blend the production characteristics of each area to balance our portfolio toward our goal of consistent production and reserve growth.

Focus on cost efficiency. We continue to concentrate in our core areas which we believe to have sizeable hydrocarbon deposits in place that will allow us to consistently increase production while controlling costs. As there is little long-term competitive sales price advantage available to a commodity producer, the costs to find, develop, and produce a commodity are important to organizational sustainability and long-term shareholder value creation. We endeavor to control costs such that our cost to find, develop and produce oil and gas is among the best performing quartile of our peer group.

Maintain Multi-Year Drilling Inventory. We focus on areas where multiple prospective productive horizons and development opportunities exist. We use our technical expertise to build and maintain a multi-year drilling inventory. A large, multi-year inventory of drilling projects increases our ability to consistently grow production and reserves. Currently, we have over 12,000 identified drilling locations in inventory. In 2008, we drilled 634 gross (490.2 net) wells.

Maintain Long Life, Low Decline Reserve Base. Long life, low decline oil and gas reserves provide a more stable growth platform than short life, high decline reserves. Long life reserves reduce reinvestment risk as they lessen the amount of reinvestment capital deployed each year to replace production. Long life, low decline oil and gas reserves also assist us in minimizing costs as stable production makes it easier to build and maintain operating economies of scale. Lastly, the inherent greater predictability of low decline oil and gas reserve production better lends itself to commodity price hedging than high decline reserves. We use our acquisition, divestiture, and drilling activity to execute this strategy.

Maintain Flexibility. Because of the volatility of commodity prices and the risks involved in drilling, we remain flexible and adjust our capital budget throughout the year. We may defer capital projects to seize an attractive acquisition opportunity. If certain areas generate higher than anticipated returns, we may accelerate drilling in those areas and decrease capital expenditures elsewhere. We also believe in maintaining a strong balance sheet and using commodity hedging. This allows us to be more opportunistic in lower price environments as well as providing more consistent financial results.

Make Complementary Acquisitions. We target complementary acquisitions in existing core areas and focus on acquisition opportunities where our existing operating and technical knowledge is transferable and drilling results can be forecast with confidence. Over the past three years, we have completed $1.1 billion of

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complementary acquisitions. These acquisitions have been located in the Southwestern and Appalachian regions.

Equity Ownership and Incentive Compensation. We want our employees to think and act like owners. To achieve this, we reward and encourage them through equity ownership in Range. All full-time employees receive equity grants. As of December 31, 2008, our employees owned equity securities (vested and unvested) that had an aggregate market value of approximately $197.4 million.

Significant Accomplishments in 2008

Production and reserve growth Fourth quarter 2008 marked the 24th consecutive quarter of sequential production growth. In 2008, our annual production averaged 385.6 Mmcfe per day, an increase of 21% from 2007. This achievement is the result of our continued drilling success and the completion and integration of complementary acquisitions. Our business is inherently volatile, and while consistent growth such as we have experienced over the past six years will be challenging to sustain, the quality of our technical teams and our sizable drilling inventory bode well for the future. Proven reserves increased 19% in 2008 to 2.7 Tcfe, marking the seventh consecutive year our proven reserves have increased.

Successful drilling program In 2008, we drilled 634 gross wells. Production was replaced by 367% through drilling in 2008, and our overall success rate was 98%. As we continue to build our drilling inventory for the future, our ability to drill a large number of wells each year on a cost effective and efficient basis is critical.

Large drilling inventory and emerging plays Maintaining a large drilling inventory is important. Our drilling inventory at year-end 2008 was slightly more than 12,000 projects. We engaged in meaningful expansion of our shale plays in 2008. We have now leased 284,000 net acres in our coal bed methane plays and 1.2 million net acres in our shale plays. We have hired additional experienced technical professionals to assist us in these emerging plays.

Record financial results and maintenance of a strong balance sheet Growth in production volumes and higher oil and gas prices drove our record financial performance in 2008. Revenue, net income, and net cash flow provided from operating activities all reached annual record highs. On the balance sheet, we refinanced $250 million of shorter-term bank debt with a like amount of senior subordinated fixed rate 7.25% notes having a 10-year maturity. This helped to align the maturity schedule of our debt with the long-term life of our assets. We also further enhanced our liquidity position by increasing commitments to the bank credit facility by $250.0 million. Financial leverage, as measured by the debt-to-capitalization ratio rose slightly from 40% at year-end 2007 to 42% at year-end 2008. Future cash flow will be enhanced by low income tax payments due to a $158.7 million net operating loss carryforward.

Successful acquisitions completed In 2008, we acquired $845.5 million of properties located in our core areas. These acquisitions included the purchase of Barnett Shale producing and non-producing properties and acreage purchases of $593.8 million, which includes a single acquisition of unproved leasehold in the Marcellus Shale for $223.9 million. Our 2008 acquisitions increased reserves by 95.6 Bcfe. See Note 3 to our consolidated financial statements.

Successful dispositions completed In first quarter 2008, we sold East Texas properties for proceeds of $64.0 million. See Note 3 to our consolidated financial statements.

Plans for 2009

Our capital expenditure budget for 2009 is currently set at $700.0 million. As has been our historical practice, we will periodically review our capital expenditures throughout the year and adjust the budget based on commodity prices and drilling success. The 2009 budget includes $538.9 million to drill 492.0 gross (315.7 net) wells and to undertake 55.0 gross (41.0 net) recompletions. Also included is $97.7 million for land, $23.9 million for seismic and $39.5 million for the expansion and enhancement of gathering systems and facilities. Approximately 40% of the budget is attributable to the Southwest Area, 58% to the Appalachia Area and 2% to the Gulf Coast Area.

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Production, Revenues and Price History

The following table sets forth information regarding oil and gas production, revenues and realized prices for the last three years. For additional information on price calculations, see information set forth in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Year Ended December 31,		
	2008	2007	2006
Production			
Gas (Mmcf)	114,323	89,595	70,713
Crude oil (Mbbls)	3,084	3,360	3,039
Natural gas liquids (Mbbls)	1,386	1,115	1,092
Total (Mmcfe) [(a)]	141,145	116,441	95,498
Oil and gas revenues ($000)			
Gas	$ 931,721	$ 613,454	$ 418,183
Crude oil	226,347	202,931	144,251
Natural gas liquids	68,492	46,152	36,705
Total oil and gas revenues	$ 1,226,560	$ 862,537	$ 599,139
Average sales prices (wellhead)			
Gas (per mcf)	$ 8.07	$ 6.54	$ 6.59
Crude oil (per bbl)	96.77	67.47	62.36
Natural gas liquids (per bbl)	49.43	41.40	33.62
Total (per mcfe) [(a)]	9.14	7.37	7.25
Average realized prices (including derivatives that qualify for hedge accounting):			
Gas (per mcf)	$ 8.15	$ 6.85	$ 5.91
Crude oil (per bbl)	73.38	60.40	47.46
Natural gas liquids (per bbl)	49.43	41.40	33.62
Total (per mcfe) [(a)]	8.69	7.41	6.27
Average realized prices (including all derivative settlements)			
Gas (per mcf)	$ 8.15	$ 7.66	$ 6.62
Crude oil (per bbl)	68.20	60.16	47.46
Natural gas liquids (per bbl)	49.43	41.40	33.62
Total (per mcfe) [(a)]	8.58	8.02	6.80

(a) Oil and NGLs are converted at the rate of one barrel equals six mcf.

Employees

As of January 1, 2009, we had 835 full-time employees, 420 of whom were field personnel. All full-time employees are eligible to receive equity awards approved by the Compensation Committee of the Board of Directors. No employees are covered by a labor union or other collective bargaining arrangement. We believe that the relationship with our employees is excellent. We regularly use independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field, on-site production operation services and certain accounting functions.

Available Information

We maintain an internet website under the name www.rangeresources.com. We make available, free of charge, on our website, the annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, our Corporate Governance Guidelines, the charters of the Audit Committee, the Compensation Committee, the Dividend Committee, and the Governance and Nominating Committee, and the Code of Business Conduct and Ethics are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102. Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including the chief executive officer and senior financial officer.

We file annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Range, that file electronically with the SEC. The public can obtain any document we file with the SEC at www.sec.gov. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Competition

We encounter substantial competition in developing and acquiring oil and gas properties, securing and retaining personnel, conducting drilling and field operations and marketing production. Competitors in exploration, development, acquisitions and production include the major oil companies as well as numerous independent oil companies, individual proprietors and others. Although our sizable acreage position and core area concentration provide some competitive advantages, many competitors have financial and other resources substantially exceeding ours. Therefore, competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources allow. Our ability to replace and expand our reserve base depends on our ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling. See Item 1A. Risk Factors.

Marketing and Customers

We market the majority of our oil and gas production from the properties we operate for both our interest and that of the other working interest owners and royalty owners. We sell our gas pursuant to a variety of contractual arrangements, generally month-to-month and one to five-year contracts. Less than 10% of our production is subject to contracts longer than five years. Pricing on the month-to-month and short-term contracts is based largely on the New York Mercantile Exchange (NYMEX) pricing, with fixed or floating basis. For one to five-year contracts, we sell our gas on NYMEX pricing, published regional index pricing or percentage of proceeds sales based on local indices. We sell less than 400 mcf per day under long-term fixed price contracts. Many contracts contain provisions for periodic price adjustment, redetermination and other terms customary in the industry. We sell our gas to utilities, marketing companies and industrial users. We sell our oil under contracts ranging in terms from month-to-month, up to as long as one year. The pricing for oil is based upon the posted prices set by major purchasers in the production area, reporting publications, or upon NYMEX pricing or fixed pricing. All oil pricing is adjusted for quality and transportation differentials. Oil and gas purchasers are selected on the basis of price, credit quality and service reliability. For a summary of purchasers of our oil and gas production that accounted for 10% or more of consolidated revenue, see Note 15 to our consolidated financial statements. Because alternative purchasers of oil and gas are usually readily available, we believe that the loss of any of these purchasers would not have a material adverse effect on us.

We enter into hedging transactions with unaffiliated third parties for significant portions of our production to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and gas prices. For a more detailed discussion, see the information set forth in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the prices for which our production can be sold. Market volatility due to international political developments, overall energy supply and demand, fluctuating weather conditions, economic growth rates and other factors in the United States and worldwide have had, and will continue to have, a significant effect on energy prices.

We incur gathering and transportation expenses to move our natural gas and crude oil from the wellhead and tanks to purchaser specified delivery points. These expenses vary based on volume, distance shipped and the fee charged by the third-party transporters. In the Southwestern and Gulf Coast Areas, our gas and oil production is transported primarily through third- party trucks, field gathering systems and transmission pipelines. Transportation capacity on these gathering systems and pipelines is occasionally constrained. In Appalachia, we own approximately 5,255 miles of gas gathering pipelines, which transport both a majority of our Appalachian gas production and third-party gas to transmission lines and directly to end-users, and interstate pipelines. For additional information, see Risk Factors *Our business depends on oil and gas transportation facilities, many of which are owned by others*, in Item 1A of this report.

Governmental Regulation

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing crude oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

In August 2005, Congress enacted the Energy Policy Act of 2005 (EPAct 2005). Among other matters, the EPAct 2005 amends the Natural Gas Act (NGA), to make it unlawful for any entity, including otherwise non-jurisdictional producers such as Range, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission (FERC), in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit any such statement necessary to make the statements not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sale or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of FERC s enforcement authority. Range does not anticipate it will be affected any differently than other producers of natural gas.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and gas industry are regularly considered by Congress, the states, the FERC, and the courts. We cannot predict when or whether any such proposals may become effective.

On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (Order 704). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report, on May 1 of each year beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC s policy statement on price reporting.

On November 20, 2008, FERC issued a final rule on the daily scheduled flow and capacity posting requirements (Order 720). Under Order 720, major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtus of gas over the previous three calendar years, are required to post daily certain information regarding the pipeline s capacity and scheduled flows for each receipt and delivery point that has a design capacity equal to or greater than 15,000 MMBtu per day. Requests for clarification and rehearing of Order 720 have been filed at FERC and a decision on those requests is pending.

Environmental and Occupational Matters

Our operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended (CERCLA), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons may include owners or operators of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, all of these persons may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties, pursuant to environmental statutes, common law or both, to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Although petroleum, including crude oil and natural gas, is not a hazardous substance under CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA and that releases of such wastes may therefore give rise to liability under CERCLA. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA or comparable state laws. Other state laws regulate the disposal of oil and gas wastes, and new state and federal legislative initiatives that could have a significant impact on us may periodically be proposed and enacted.

We also may incur liability under the Resource Conservation and Recovery Act, as amended (RCRA), which imposes requirements related to the handling and disposal of solid and hazardous wastes. While there is an exclusion from the definition of hazardous wastes for drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy, these wastes may be regulated by the United States Environmental Protection Agency (EPA) or state agencies as non-hazardous solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, can be regulated as hazardous wastes. Although the costs of managing wastes classified as hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies.

We currently own or lease, and have in the past owned or leased, properties that for many years have been used for the exploration and production of crude oil and natural gas. Petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under other locations where such materials have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and comparable state laws and regulations. Under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

The Federal Water Pollution Control Act, as amended (FWPCA), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the state. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as SPCC plans, in connection with on-site storage of greater than threshold quantities of oil. We are currently undertaking a review of recently acquired oil and gas properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans, the costs of which are not expected to be substantial.

The Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or use specific equipment or technologies to control emissions. While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission-related issues, we do not believe that such requirements will have a material adverse effect on our operations.

Changes in environmental laws and regulations sometimes occur, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements for any substances used or produced in our operations could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of greenhouse gases and more than one-third of the states, either individually or through multi-state initiatives already have begun implementing legal measures to reduce emissions of greenhouse gases. As an alternative to reducing emissions of greenhouse gases, the Congress may consider the implementation of a program to tax the emission of carbon dioxide and other greenhouse gases. Also, the U.S. Supreme Court s holding in its 2007 decision, *Massachusetts, et. al. v. EPA*, that carbon dioxide may be regulated as an air pollutant under the federal Clean Air Act could result in future regulation of greenhouse gas emissions from stationary sources, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. In July 2008, EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act. Although the notice did not propose any specific new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future. It is possible that new laws or regulations could establish a greenhouse cap and trade program, whereby major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, would be required to acquire and surrender emission allowances. While we do not operate stationary sources that emit significant quantities of greenhouse gases, including carbon dioxide, we do utilize gas processing plants to process the natural gas that we produce and, thus if such processors were to incur increased costs to acquire and surrender emission allowances or otherwise to capture and dispose of greenhouse gases, it is possible that these costs, which might be significant, could be passed along to us as well as similarly situated producers. Moreover, any adoption of a program to tax the emission of carbon dioxide and other greenhouse gases potentially could be imposed on us and other similarly situated producers of natural gas. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business or demand for our products. Given the possible impact of legislation and/or regulation of carbon dioxide, methane and other greenhouse gases, we have considered and expect to continue to consider the impact of laws or regulations intended to address climate change on our operations. We do not believe our operations require reporting or monitoring of carbon dioxide emissions under existing laws and regulations; however, we do operate mobile equipment in the normal course of our business that emits carbon dioxide as well as some stationary engines that power compressors and pumping equipment. Methane is a primary constituent of natural gas and, like all oil and gas exploration and production companies, we produce significant quantities of natural gas; however, such production of natural gas, including its constituent hydrocarbon including methane, is gathered and transported in pipelines under pressure and we therefore do not emit significant quantities of methane in connection with our operations. Given our lack of significant points of carbon dioxide emissions, we have focused most of our efforts on physical environmental ground, water and air issues in our operations

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended (OSHA), and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA s hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2008, nor do we anticipate that such expenditures will be material in 2009.

ITEM 1A. RISK FACTORS

We are subject to various risks and uncertainties in the course of our business. The following summarizes some, but not all, of the risks and uncertainties, which may adversely affect our business, financial condition or results of operations. Our business could also be impacted by additional risks and uncertainties not currently known to us or that we currently deem to be immaterial.

Risks Related to Our Business

Volatility of oil and gas prices significantly affects our cash flow and capital resources and could hamper our ability to produce oil and gas economically

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Oil and gas prices are volatile, and a decline in prices adversely affects our profitability and financial condition. Higher oil and gas prices have contributed to our positive earnings over the last several years. The oil and gas industry is typically cyclical, and prices for oil and gas have been highly volatile. Historically, the industry has experienced severe downturns characterized by oversupply and/or weak demand. Long-term supply and demand for oil and gas is uncertain and subject to a myriad of factors such as:

- the domestic and foreign supply of oil and gas;
- the price and availability of alternative fuels;
- weather conditions;
- the level of consumer demand;
- the price of foreign imports;
- worldwide economic conditions;
- the availability, proximity and capacity of transportation facilities and processing facilities;
- the effect of worldwide energy conservation efforts;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations and taxes.

The recent decreases in oil and gas prices have adversely affected our revenues, net income, cash flow and proved reserves. Significant price decreases could have a material adverse effect on our operations and limit our ability to fund capital expenditures. Without the ability to fund capital expenditures, we would be unable to replace reserves and production. Sustained decreases in oil and gas prices will further adversely affect our revenues, net income, cash flows, proved reserves and our ability to fund capital expenditures.

Information concerning our reserves and future net reserve estimates is uncertain

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and their values, including many factors beyond our control. Estimates of proved reserves are by their nature uncertain. Although we believe these estimates are reasonable, actual production, revenues and costs to develop will likely vary from estimates and these variances could be material.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of oil and gas that cannot be directly measured. As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may calculate different estimates of reserves and future net cash flows based on the same available data. Because of the subjective nature of oil and gas reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- the amount and timing of oil and gas production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

The discounted future net cash flows from our proved reserves included in this report should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles, the estimated discounted future net revenues from our proved reserves are based generally on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. In addition, the 10 percent discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under generally accepted accounting principles is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and gas industry in general.

If oil and gas prices decrease or drilling efforts are unsuccessful, we may be required to record write downs of our oil and gas properties

We have been in the past and were in 2008, required to write down the carrying value of certain of our oil and gas properties, and there is a risk that we will be required to take additional write downs in the future. Writedowns may occur when oil and gas prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in our drilling results or mechanical problems with wells where the cost to redrill or repair does not justify the expense.

Accounting rules require that the carrying value of oil and gas properties be periodically reviewed for possible impairment. Impairment is recognized when the book value of a proven property is greater than the expected undiscounted future net cash flows from that property and on acreage when conditions indicate the carrying value is not recoverable. We may be required to write down the carrying value of a property based on oil and gas prices at the time of the impairment review, or as a result of continuing evaluation of drilling results, production data, economics and other factors. While an impairment charge reflects our long-term ability to recover an investment, it does not impact cash or cash flow from operating activities, but it does reduce our reported earnings and increases our leverage ratios.

Significant capital expenditures are required to replace our reserves

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, our bank credit facility and debt and equity issuances. From time to time, we have also engaged in asset monetization transactions. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and gas and our success in developing and producing new reserves. If our access to capital were limited due to numerous factors which could include a decrease in revenues due to lower gas and oil prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to replace our reserves. We may not be able to incur additional bank debt, issue debt or equity, engage in asset monetization or access other methods of financing on an economic basis to meet our reserve replacement requirements.

The amount available for borrowing under our bank credit facility is subject to a borrowing base, which is determined by our lenders taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. The recent decline in oil and gas prices has adversely impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base. If commodity prices continue to decline in 2009, it will have similar adverse effects on our reserves and borrowing base.

Our future success depends on our ability to replace reserves that we produce

Because the rate of production from oil and gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future oil and gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

Our indebtedness could limit our ability to successfully operate our business

We are leveraged and our exploration and development program will require substantial capital resources depending on the level of drilling and the expected cost of services. Our existing operations will also require ongoing capital expenditures. In addition, if we decide to pursue additional acquisitions, our capital expenditures will increase, both to complete such acquisitions and to explore and develop any newly acquired properties.

The degree to which we are leveraged could have other important consequences, including the following:

- we may be required to dedicate a substantial portion of our cash flows from operations to the payment of our indebtedness, reducing the funds available for our operations;
- a portion of our borrowings are at variable rates of interest, making us vulnerable to increases in interest rates;
- we may be more highly leveraged than some of our competitors, which could place us at a competitive disadvantage;
- our degree of leverage may make us more vulnerable to a downturn in our business or the general economy;

we are subject to numerous financial and other restrictive covenants contained in our existing credit agreements the breach of which could materially and adversely impact our financial performance;

our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and

we may have difficulties borrowing money in the future.

Despite our current levels of indebtedness, we still may be able to incur substantially more debt. This could further increase the risks described above. In addition to those risks above, we may not be able to obtain funding on acceptable terms because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly.

Our business is subject to operating hazards that could result in substantial losses or liabilities that may not be fully covered under our insurance policies

Oil and gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic natural gas and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and penalties; or
- suspension of operations.

As we drill to deeper horizons and in more geologically complex areas, we could experience a greater increase in operating and financial risks due to inherent higher reservoir pressures and unknown downhole risk exposures. As we continue to drill deeper, the number of rigs capable of drilling to such depths will be fewer and we may experience greater competition from other operators.

We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. We have experienced substantial increases in premiums, especially in areas affected by hurricanes and tropical storms. Insurers have imposed revised limits affecting how much the insurers will pay on actual storm claims plus the cost to re-drill wells where substantial damage has been incurred. Insurers are also requiring us to retain larger deductibles and reducing the scope of what insurable losses will include. Even with the increase in future insurance premiums, coverage will be reduced, requiring us to bear a greater potential risk if our oil and gas properties are damaged. We do not maintain any business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs that is not fully covered by insurance, it could have a material adverse affect on our financial condition and results of operations.

We are subject to financing and interest rate exposure risks

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in our credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, at December 31, 2008, approximately 61% of our debt is at fixed interest rates with the remaining 39% subject to variable interest rates.

Recent and continuing disruptions and volatility in the global finance markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital; a significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results. We are exposed to some credit risk related to our senior credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under our existing revolving line of credit if it experiences liquidity problems.

Difficult conditions in the global capital markets and the economy generally may materially adversely affect our business and results of operations

Our results of operations are materially affected by conditions in the domestic capital markets and the economy generally. The stress experienced by domestic capital markets that began in the second half of 2007 continued and substantially increased during third quarter 2008. Recently, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market and a declining real estate market in the U.S. have contributed to increased volatility and diminished expectations of the economy and the markets going forward. These factors, combined with volatile oil and gas prices, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown. In addition, the fixed-income markets are experiencing a period of extreme volatility which has negatively impacted market liquidity conditions.

The capital markets have experienced decreased liquidity, increased price volatility, credit downgrade events, and increased probabilities of default. These events and the continuing market upheavals may have an adverse effect on us because our liquidity and ability to fund our capital expenditures is dependent in part upon our bank borrowings and access to the public capital markets. Our revenues are likely to decline in such circumstances. In addition, in the event of extreme prolonged market events, such as a worsening of the global credit crisis, we could incur significant losses.

Hedging transactions may limit our potential gains and involve other risks

To manage our exposure to price risk, we, from time to time, enter into hedging arrangements, utilizing commodity derivatives with respect to a significant portion of our future production. The goal of these hedges is to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if oil and gas prices rise above the price established by the hedge.

In addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our futures contracts fail to perform under the contracts; or
- an event materially impacts oil or gas prices or the relationship between the hedged price index and the oil and gas sales price.

We cannot assure you that any hedging transactions we may enter into will adequately protect us from declines in the prices of oil and gas. On the other hand, where we choose not to engage in hedging transactions in the future, we may be more adversely affected by changes in oil and gas prices than our competitors who engage in hedging transactions.

Many of our current and potential competitors have greater resources than we have and we may not be able to successfully compete in acquiring, exploring and developing new properties

We face competition in every aspect of our business, including, but not limited to, acquiring reserves and leases, obtaining goods, services and employees needed to operate and manage our business and marketing oil and gas. Competitors include multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do. As a result, these competitors may be able to address these competitive factors more effectively than we can or weather industry downturns more easily than we can.

The demand for field services and their ability to meet that demand may limit our ability to drill and produce our oil and natural gas properties

In a rising price environment, such as those experienced in 2007 and early 2008, well service providers and related equipment and personnel are in short supply. This causes escalating prices, the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures increase the actual cost of services, extend the time to secure such services and add costs for damages due to accidents sustained from the over use of equipment and inexperienced personnel. In some cases, we are operating in new areas where services and infrastructure do not exist or in urban areas which are more restrictive.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase

Section 1(b) of the Natural Gas Act of 1938 (NGA) exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts, or Congress.

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While our natural gas gathering operations are generally exempt from FERC regulation under the NGA, our gas gathering operations may be subject to certain FERC reporting and posting requirements in a given year. FERC has recently issued a final rule (as amended by orders on rehearing, Order 704) requiring certain participants in the natural gas market, including certain gathering facilities and natural gas marketers that engage in a minimum level of natural gas sales or purchases, to submit annual reports regarding those transactions to FERC. In addition, FERC has issued a final rule (Order 720) requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering more than an average of 50 million MMBtu of gas over the previous three calendar years, to post daily certain information regarding the pipeline s capacity and scheduled flows for each receipt and delivery point that has design capacity equal to or greater than 15,000 MMBtu per day.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. FERC s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipelines rates and rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of our operations, please see Government Regulation in item 1 of this report.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines

Under the EP Act 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated as a natural gas company by FERC under the NGA, FERC has adopted regulations that may subject certain of four otherwise non-FERC jurisdiction facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. We also must comply the anti-market manipulation rules enforced by FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject Range to civil penalty liability. For more information regarding regulation of our operations, please see Government Regulation in Item 1 of this report.

The oil and gas industry is subject to extensive regulation

The oil and gas industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on participants in the oil and gas industry. Compliance with such rules and regulations often increases our cost of doing business, delays our operations and, in turn, decreases our profitability.

Our operations are subject to numerous and increasingly strict federal, state and local laws, regulations and enforcement policies relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws, regulations and enforcement policies and may incur costs arising out of property damage or injuries to employees and other persons. These costs may result from our current and former operations and even may be caused by previous owners of property we own or lease. Any past, present or future failure by us to completely comply with environmental laws, regulations and enforcement policies could cause us to incur substantial fines, sanctions or liabilities from cleanup costs or other damages. Incurrence of those costs or damages could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business

We could be subject to significant liabilities related to our acquisitions. It generally is not feasible to review in detail every individual property included in an acquisition. Ordinarily, a review is focused on higher valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems in all of the properties, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed.

For example, several years ago, we consummated a large acquisition that proved extremely disappointing. Production from the acquired properties fell more rapidly than anticipated and further development results were below the results we had originally projected. The poor production performance of these properties resulted in material downward reserve revisions. There is no assurance that our recent and/or future acquisition activity will not result in similarly disappointing results.

In addition, there is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our acquisition strategy is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are unable to obtain financing on terms acceptable to us or regulatory approvals.

Acquisitions often pose integration risks and difficulties. In connection with recent and future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Future acquisitions could result in our incurring additional debt, contingent liabilities, expenses and diversion of resources, all of which could have a material adverse effect on our financial condition and operating results.

Our success depends on key members of our management and our ability to attract and retain experienced technical and other professional personnel

Our success is highly dependent on our management personnel and none of them is currently subject to an employment contract. The loss of one or more of these individuals could have a material adverse effect on our business. Furthermore, competition for experienced technical and other professional personnel is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected. Also, the loss of experienced personnel could lead to a loss of technical expertise.

Drilling is a high-risk activity

The cost of drilling, completing, and operating a well is often uncertain, and many factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce enough oil and gas to be commercially viable after drilling, operating and other costs. Furthermore, our drilling and producing operations may be curtailed, delayed, or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of drilling rigs, equipment, labor, or other services;
- unexpected operational events and drilling conditions;
- reductions in oil and gas prices;
- limitations in the market for oil and gas;
- adverse weather conditions;
- facility or equipment malfunctions;
- equipment failures or accidents;
- title problems;
- pipe or cement failures;
- casing collapses;
- compliance with environmental and other governmental requirements;
- environmental hazards, such as natural gas leaks, oil spills, pipelines ruptures, and discharges of toxic gases;

lost or damaged oilfield drilling and service tools;

unusual or unexpected geological formations;

loss of drilling fluid circulation;

pressure or irregularities in formations;

fires;

natural disasters;

blowouts, surface craterings and explosions; and

uncontrollable flows of oil, natural gas or well fluids.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

New technologies may cause our current exploration and drilling methods to become obsolete

The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our business depends on oil and gas transportation facilities, most of which are owned by others

The marketability of our oil and gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. We generally do not purchase firm transportation on third party facilities and therefore, our production transportation can be interrupted by those having firm arrangements. Although, recently we have entered into some firm arrangements in certain production areas. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and gas. If any of these third party pipelines and other facilities become partially or fully unavailable to transport our product, or if the natural gas quality specifications for a natural gas pipeline or facility changes so as to restrict our ability to transport natural gas on those pipelines or facilities, our revenues could be adversely affected.

The disruption of third-party facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations

If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or restructure our debt. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

We exist in a litigious environment

Any constituent could bring suit regarding our existing or planned operations or allege a violation of an existing contract. Any such action could delay when planned operations can actually commence or could cause a halt to existing production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, but halting existing production or delaying planned operations could impact our future operations and financial condition. Such legal disputes could also distract management and other personnel from their primary responsibilities.

Our financial statements are complex

Due to United States generally accepted accounting rules and the nature of our business, our financial statements continue to be complex, particularly with reference to hedging, asset retirement obligations, equity awards, deferred taxes and the accounting for our deferred compensation plans. We expect such complexity to continue and possibly increase.

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Risks Related to Our Common Stock

Common stockholders will be diluted if additional shares are issued

In 2004 and 2005, we sold 33.8 million shares of common stock to finance acquisitions. In 2006, we issued 6.5 million shares as part of the Stroud acquisition. In 2007, we sold 8.1 million shares of common stock to finance acquisitions. In 2008, we sold 4.4 million shares of common stock with the proceeds used to pay down a portion of the outstanding balance of our bank credit facility. Our ability to repurchase securities for cash is limited by our bank credit facility and our senior subordinated note agreements. We also issue restricted stock and stock appreciation rights to our employees and directors as part of their compensation. In addition, we may issue additional shares of common stock, additional subordinated notes or other securities or debt convertible into common stock, to extend maturities or fund capital expenditures, including acquisitions. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Dividend limitations

Limits on the payment of dividends and other restricted payments, as defined, are imposed under our bank credit facility and under our senior subordinated note agreements. These limitations may, in certain circumstances, limit or prevent the payment of dividends independent of our dividend policy.

Our stock price may be volatile and you may not be able to resell shares of our common stock at or above the price you paid

The price of our common stock fluctuates significantly, which may result in losses for investors. The market price of our common stock has been volatile. From January 1, 2006 to December 31, 2008, the price of our common stock reported by the New York Stock Exchange ranged from a low of $21.74 per share to a high of $76.81 per share. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in oil and gas prices;
- variations in quarterly drilling, recompletions, acquisitions and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel; or
- future sales of our stock.

We may fail to meet expectations of our stockholders or of securities analysts at some time in the future and our stock price could decline as a result.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of the date of this filing, we have no unresolved comments from the staff of the Securities and Exchange Commission.

ITEM 2. PROPERTIES

The table below summarizes certain data for our core operating areas for the year ended December 31, 2008.

Area	Average Daily Production (mcfe per day)	Total Production (mcfe)	Percentage of Total Production	Total Proved Reserves (Mmcfe)	Percentage of Total Proved Reserves
Southwest	235,289	86,115,662	61%	1,304,154	49%
Appalachia	139,832	51,178,557	36%	1,312,426	50%

Gulf Coast	10,521	3,850,597	3%	36,985	1%
	385,642	141,144,816	100%	2,653,565	100%

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We have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments; therefore, segment reporting is not applicable to us. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Southwest Area

The Southwest Area conducts drilling, production and field operations in the Barnett Shale of North Central Texas, the Permian Basin of West Texas and eastern New Mexico, and the East Texas Basin, as well as in the Texas Panhandle and the Anadarko Basin of western Oklahoma. In the Southwest Area, we own 2,308 net producing wells, 96% of which we operate. Our average working interest is 72%. We have approximately 841,000 gross (547,000 net) acres under lease.

Total proved reserves increased 255.8 Bcfe, or 24%, at December 31, 2008 when compared to year-end 2007. Production and an unfavorable reserve revision for lower prices was more than offset by property purchases (95.6 Bcfe) and drilling additions (293.4 Bcfe). Annual production increased 22% over 2007. During 2008, the region spent $536.2 million to drill 242 (209.8 net) development wells, of which 237 (205.8 net) were productive, and 18 (14.0 net) exploratory wells, of which 13 (11.1 net) were productive. During the year, the region achieved a 97% drilling success rate.

At December 31, 2008, the Southwest Area had a development inventory of 552 proven drilling locations and 352 proven recompletions. During the year, the Southwest Area drilled 88 proven locations and added 263 new locations. Development projects include recompletions, infill drilling and to a lesser extent, installation of secondary recovery projects. These activities also include increasing reserves and production through cost control, upgrading lifting equipment, improving gathering systems and surface facilities, and performing restimulations and refracturing operations.

Appalachia Area

Our properties in this area are located in the Appalachian Basin in the northeastern United States, principally in Pennsylvania, Ohio, New York, West Virginia and Virginia. The reserves principally produce from the Pennsylvanian (coalbed formation), Upper Devonian, Medina, Clinton, Queenston, Big Lime, Marcellus Shale, Niagaran Reef, Knox, Huntersville Chert, Oriskany and Trenton Black River formations at depths ranging from 2,500 to 12,500 feet. Generally, after initial flush production, most of these properties are characterized by gradual decline rates, typically producing for 10 to 35 years. We own 10,278 net producing wells, 59% of which we operate, and 5,255 miles of gas gathering lines. Our average working interest is 73%. We have approximately 2.7 million gross (2.3 million net) acres under lease, which include 407,800 acres where we also own a royalty interest.

Reserves at December 31, 2008 increased 162.3 Bcfe, or 14%, from 2007 due to drilling additions (214.5 Bcfe) that were partially offset by production. Annual production increased 18% over 2007. During 2008, the region spent $359.5 million to drill 361 (257.4 net) development wells, all of which were productive, and 7.0 (5.0 net) exploratory wells, all of which were productive. As a result, the region achieved a 100% drilling success rate. At December 31, 2008, the Appalachia Area had an inventory of 3,800 proven drilling locations and 500 proven recompletions. During the year, the Appalachia Area drilled 192 proven locations and added 519 new locations.

Gulf Coast Area

The Gulf Coast properties are located onshore in Texas, Louisiana and Mississippi. Our major fields produce from the Yegua formations at depths of 12,000 to 14,000 feet in the Upper Texas Gulf Coast, the Upper Oligocene in South Louisiana at depths of 10,000 to 12,000 feet and the Sligo and Hosston formations at depths of 15,000 to 16,500 feet in the Oakvale field in Mississippi. We have approximately 116,000 gross (82,000 net) acres under lease. We own 18 net producing wells in this Area, 88% of which we operate. Our average working interest is 47%.

Reserves increased 2.7 Bcfe, or 8%, from 2007 with drilling additions (10.5 Bcfe) partially offset by an unfavorable reserve revision and production. On an annual basis, production increased 61% from 2007. During 2008, the region spent $34.3 million to drill 5.0 (3.7 net) development wells, of which 4.0 (2.8 net) were productive, and 1.0 (0.3 net) exploratory well that was a dry hole. During the year, the Gulf Coast Area had a 69% drilling success rate. At December 31, 2008, the Gulf Coast Area had an inventory of 5 proven drilling locations and 10 proven recompletions.

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Proved Reserves

The following table sets forth our estimated proved reserves at the end of each of the past five years:

	December 31, 2008	2007	2006	2005	2004
Natural gas (Mmcf)					
Developed	1,337,978	1,144,709	875,395	724,876	580,006
Undeveloped	875,568	688,088	560,583	400,534	366,422
Total	2,213,546	1,832,797	1,435,978	1,125,410	946,428
Oil and NGLs (Mbbls)					
Developed	49,009	47,015	37,750	33,029	27,715
Undeveloped	24,327	19,645	15,957	13,863	10,451
Total	73,336	66,660	53,707	46,892	38,166
Total (Mmcfe) [(a)]	2,653,565	2,232,762	1,758,226	1,406,762	1,175,425
% Developed	62%	64%	63%	66%	64%

(a) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf.

The following table sets forth summary information by area with respect to estimated proved reserves at December 31, 2008:

	Reserve Volumes				PV-10 [(a)]	
	Oil & NGL (Mbbls)	Natural Gas (Mmcf)	Total (Mmcfe)	%	Amount (In thousands)	%
Southwest	54,967	974,353	1,304,154	49%	$ 1,819,212	54%
Appalachia	17,582	1,206,933	1,312,426	50%	1,493,961	44%
Gulf Coast	787	32,260	36,985	1%	87,073	2%
Total	73,336	2,213,546	2,653,565	100%	$ 3,400,246	100%

(a) PV-10 was prepared using prices in effect at the end of 2008, discounted at 10% per annum. Year-end PV-10 may be considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of PV-10 is relevant and useful to our investors as supplemental disclosure to the standardized measure, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, PV-10 is based on prices and discount factors that are consistent for all companies. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the PV-10 amount is the discounted estimated future income tax of $819.0 million at December 31, 2008.

At year-end 2008, the following independent petroleum consultants reviewed our reserves: DeGolyer and MacNaughton (Southwest and Gulf Coast), H.J. Gruy and Associates, Inc. (Southwest), and Wright and Company, Inc. (Appalachia). These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. At December 31, 2008, these consultants collectively reviewed approximately 87% of our proved reserves. All estimates of oil and gas reserves are subject to uncertainty. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. We did not file any reports during the year ended December 31, 2008 with any federal authority or agency with respect to our estimates of oil and gas reserves.

The following table sets forth the estimated future net cash flows, excluding open hedging contracts, from proved reserves, the present value of those net cash flows (PV-10), and the expected benchmark prices and average field prices used in projecting net cash flows over the past five years (in millions except prices):

	December 31,				
	2008	2007	2006	2005	2004
Future net cash flows	$8,441	$11,908	$6,391	$10,429	$5,035
Present value					
Before income tax	$3,400	$ 5,205	$2,771	$ 4,887	$2,396
After income tax (Standardized Measure)	$2,581	$ 3,666	$2,002	$ 3,384	$1,749
Benchmark prices (NYMEX)					
Oil price (per barrel)	$44.60	$ 95.98	$61.05	$ 61.04	$43.33
Gas price (per mcf)	$ 5.71	$ 6.80	$ 5.64	$ 10.08	$ 6.18
Wellhead prices					
Oil price (per barrel)	$42.76	$ 91.88	$57.66	$ 57.80	$40.44
Gas price (per mcf)	$ 5.23	$ 6.44	$ 5.24	$ 9.83	$ 6.05

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations, prepared in accordance with Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities, are based on costs and prices in effect at December 31 of each year, without escalation. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 2008. We also own royalty interests in an additional 1,900 wells in which we do not own a working interest. If we own both a royalty and a working interest in a well such interests are included in the table below. Wells are classified as crude oil or gas according to their predominant production stream. We do not have a significant number of dual completions.

	Total Wells		Average Working Interest
	Gross	Net	
Natural gas	14,902	10,471	70%
Crude oil	2,474	2,133	86%
Total	17,376	12,604	73%

The day-to-day operations of oil and gas properties are the responsibility of the operator designated under pooling or operating agreements. The operator supervises production, maintains production records, employs or contracts for field personnel and performs other functions. An operator receives reimbursement for direct expenses incurred in the performance of its duties as well as monthly per-well producing and drilling overhead reimbursement at rates customarily charged by unaffiliated third parties. The charges customarily vary with the depth and location of the well being operated.

Acreage

We own interests in developed and undeveloped oil and gas acreage. These ownership interests generally take the form of working interests in oil and gas leases that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells or wells capable of production even though shallower or deeper horizons may not have been fully explored. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not the acreage contains proved reserves.

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The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2008. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alabama			72,914	61,679	72,914	61,679
Louisiana	2,567	1,650	12,781	8,080	15,348	9,730
Michigan	162	162	123	123	285	285
Mississippi	5,064	2,706	18,973	6,940	24,037	9,646
New Mexico	8,090	5,878			8,090	5,878
New York	186,867	177,890	128,820	113,716	315,687	291,606
Ohio	272,671	255,283	244,535	223,332	517,206	478,615
Oklahoma	165,700	102,097	151,242	82,306	316,942	184,403
Pennsylvania	496,804	443,785	831,010	725,946	1,327,814	1,169,731
Texas	254,020	175,363	265,019	182,556	519,039	357,919
Virginia	129,500	56,240	156,102	71,963	285,602	128,203
West Virginia	81,700	50,178	130,908	125,218	212,608	175,396
	1,603,145	1,271,232	2,012,427	1,601,859	3,615,572	2,873,091
Average working interest		79%		80%		79%

Undeveloped Acreage Expirations

The table below summarizes by year our undeveloped acreage scheduled to expire in the next five years.

	Acres		% of Total
As of December 31,	Gross	Net	Undeveloped
2009	351,165	257,926	15%
2010	249,046	196,864	12%
2011	352,510	290,392	17%
2012	222,361	201,357	12%
2013	136,219	124,997	7%

We have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally not exceeding two years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire and will allow additional acreage to expire in the future.

Drilling Results

The following table summarizes drilling activity for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. As of December 31, 2008, we were in the process of drilling 44 gross (29.0 net) wells.

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	602.0	466.0	942.0	680.5	992.0	689.7
Dry	6.0	4.9	9.0	7.9	8.0	4.6
Exploratory wells						

Productive	20.0	16.1	11.0	6.3	12.0	6.9
Dry	6.0	3.2	5.0	3.5	5.0	2.6
Total wells						
Productive	622.0	482.1	953.0	686.8	1,004.0	696.6
Dry	12.0	8.1	14.0	11.4	13.0	7.2
Total	634.0	490.2	967.0	698.2	1,017.0	703.8
Success ratio	98%	98%	99%	98%	99%	99%

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Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- development obligations under oil and gas leases; or
- net profit interests.

ITEM 3. LEGAL PROCEEDINGS

We have been named as a defendant in a number of legal actions arising in the ordinary course of business. In the opinion of management, such litigation and claims are likely to be resolved without a material adverse effect on our financial position or liquidity, although an unfavorable outcome could have a material adverse effect on the operations of a given interim period or year. See also Note 14 to our consolidated financial statements.

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

There were no matters submitted to a vote of our security holders during fourth quarter 2008.

PART II

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

Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol RRC. During 2008, trading volume averaged 3.3 million shares per day. In 2007, we were selected to be included in the S&P 500 Index. The following table shows the quarterly high and low sale prices and cash dividends declared as reported on the NYSE composite tape for the past two years.

	High	Low	Cash Dividends Declared
2007			
First quarter	$33.80	$25.59	$0.03
Second quarter	40.50	33.40	0.03
Third quarter	41.87	33.28	0.03
Fourth quarter	51.88	37.17	0.04
2008			
First quarter	$65.53	$43.02	$0.04
Second quarter	76.81	61.13	0.04
Third quarter	72.98	37.34	0.04
Fourth quarter	44.15	23.77	0.04

Between January 1, 2009 and February 19, 2009, the common stock traded at prices between $31.19 and $41.80 per share. Our senior subordinated notes are not listed on an exchange, but trade over-the-counter.

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Holders of Record

On February 19, 2009, there were approximately 1,652 holders of record of our common stock.

Dividends

The payment of dividends is subject to declaration by the Board of Directors and depends on earnings, capital expenditures and various other factors. The bank credit facility and our senior subordinated notes allow for the payment of common and preferred dividends, with certain limitations. The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of our board and will depend upon our level of earnings and capital expenditures and other matters that the Board of Directors deems relevant. For more information, see information set forth in Item 7 of this report Management s Discussion and Analysis of Financial Condition and Results of Operations.

Issuer Purchases of Equity Securities

We have a repurchase program approved by the Board of Directors in 2008 for the repurchase of up to $10.0 million of common stock based on market conditions and opportunities. There were no repurchases during fourth quarter 2008. As of December 31, 2008, we have $6.8 million remaining under this authorization.

Stockholder Return Performance Presentation*

The following graph is included in accordance with the SEC s executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of Range s common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for the five years ended December 31, 2008. The graph assumes that $100 was invested in the Company s common stock and each index on December 31, 2003.

	As of December 31,					
	2003	2004	2005	2006	2007	2008
Range Resources Corporation	$100	$217	$418	$436	$815	$546
DJ U.S. Expl. & Prod. Index	100	140	230	241	344	204
S&P 500 Index	100	109	112	128	132	81

* The performance graph and the information contained in this section is not soliciting material, is being furnished not filed with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date

hereof and irrespective of any general incorporation language contained in such filing.

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ITEM 6. SELECTED FINANCIAL DATA

The following table shows selected financial information for the five years ended December 31, 2008. Significant producing property acquisitions in 2006 and 2004 affect the comparability of year-to-year financial and operating data. In March 2007, we sold our Gulf of Mexico properties for proceeds of $155.0 million. Accordingly, the financial and statistical data contained in the following discussion reflects our Gulf of Mexico operations as discontinued operations. All weighted average shares and per share data have been adjusted for the three-for-two stock split effected December 2, 2005. This information should be read in conjunction with Item 7 of this report Management s Discussion and Analysis of Financial Condition and Results of Operations, and our consolidated financial statements and related notes included elsewhere in this report.

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(in thousands, except per share data)				
Balance Sheet Data:					
Current assets [(a)]	$ 404,311	$ 261,814	$ 388,925	$ 207,977	$ 136,336
Current liabilities [(b)]	353,514	305,433	251,685	321,760	177,162
Oil and gas properties, net	4,852,710	3,503,808	2,608,088	1,679,593	1,340,077
Total assets	5,562,543	4,016,508	3,187,674	2,018,985	1,595,406
Bank debt	693,000	303,500	452,000	269,200	423,900
Subordinated notes	1,097,562	847,158	596,782	346,948	196,656
Stockholders equity[(c)]	2,457,833	1,728,022	1,256,161	696,923	566,340
Weighted average dilutive shares outstanding	155,943	149,911	138,711	129,125	97,998
Cash dividends declared per common share	0.16	0.13	0.09	.0599	.0267
Cash Flow Data:					
Net cash provided from operating activities	$ 824,767	$ 642,291	$ 479,875	$ 325,745	$ 209,249
Net cash used in investing activities	1,731,777	1,020,572	911,659	432,377	624,301
Net cash provided from financing activities	903,745	379,917	429,416	93,000	432,803

(a) 2007 included deferred tax assets of $26.9 million compared to $61.7 million in 2005 and $26.3 million in 2004. 2008 includes $221.4 million unrealized derivative assets compared to $53.0 million in

2007 and $93.6 million in 2006.

(b) 2008 includes unrealized derivative liabilities of $10,000 compared to $30.5 million in 2007, $4.6 million in 2006, $160.1 million in 2005 and $61.0 million in 2004. 2008 includes $33.0 million of deferred tax liabilities.

(c) Stockholders equity includes other comprehensive income (loss) of $77.5 million in 2008 compared to ($26.8 million) in 2007, $36.5 million in 2006, ($147.1 million) in 2005 and ($43.3 million) in 2004.

Statement of Operations Data:

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(in thousands, except per share data)				
Revenues					
Oil and gas sales	$ 1,226,560	$ 862,537	$ 599,139	$ 495,470	$ 278,903
Transportation and gathering	4,577	2,290	2,422	2,306	2,002
Loss on retirement of securities					(39)
Derivative fair value income (loss)	70,135	(7,767)	142,395	10,303	614
Other	21,675	5,031	856	1,024	1,588
Total revenue	1,322,947	862,091	744,812	509,103	283,068
Costs and expenses					
Direct operating	142,387	107,499	81,261	57,866	39,419
Production and ad valorem taxes	55,172	42,443	36,415	30,822	19,845
Exploration	67,690	43,345	44,088	29,529	12,619
Abandonment and impairment of unproved properties	47,906	6,750	257	623	1,161
General and administrative	92,308	69,670	49,886	33,444	20,634
Deferred compensation plan	(24,689)	28,332	6,873	29,474	19,176
Interest expense and dividends on trust preferred	99,748	77,737	55,849	37,619	22,437
Depletion, depreciation and amortization	299,831	220,578	154,482	113,741	79,467
Total costs and expenses	780,353	596,354	429,111	333,118	214,758
Income from continuing operations before income taxes	542,594	265,737	315,701	175,985	68,310
Income tax provision (benefit)					
Current	4,268	320	1,912	1,071	(245)
Deferred	192,168	98,441	119,840	64,809	25,327
	196,436	98,761	121,752	65,880	25,082
Income from continuing operations	346,158	166,976	193,949	110,105	43,228
Discontinued operations, net of taxes		63,593	(35,247)	906	(997)
Net income	346,158	230,569	158,702	111,011	42,231
Preferred dividends					(5,163)
Net income available to common stockholders	$ 346,158	$ 230,569	$ 158,702	$ 111,011	$ 37,068

Earnings per common share:										
Basic income from continuing operations	$	2.29	$	1.16	$	1.45	$	0.89	$	0.41
discontinued operations				0.44		(0.26)				(0.01)
net income	$	2.29	$	1.60	$	1.19	$	0.89	$	0.40
Diluted income from continuing operations	$	2.22	$	1.11	$	1.39	$	0.85	$	0.39
discontinued operations				0.43		(0.25)		0.01		(0.01)
net income	$	2.22	$	1.54	$	1.14	$	0.86	$	0.38

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with Item 6, Selected Financial Data and our consolidated financial statements and the accompanying notes included elsewhere in this Form 10-K.

Statements in our discussion may be forward-looking. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. See Disclosures Regarding Forward-Looking Statements at the beginning of this Annual Report and Risk Factors in Item 1A for additional discussion of some of these factors and risks.

Overview of Our Business

We are an independent oil and gas company engaged in the exploration, development and acquisition of oil and gas properties, primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We operate in one segment. We have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Our strategy is to increase reserves and production through internally generated drilling projects coupled with complementary acquisitions. Our revenues, profitability and future growth depend substantially on prevailing prices for oil and gas and on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. We use the successful efforts method of accounting for our oil and gas activities. Our corporate headquarters are in Fort Worth, Texas.

Industry Environment

We operate entirely within the United States, a mature region for the exploration and production of oil and gas. Although new discoveries of oil and gas occur in the United States, because it is a mature region, the size and frequency of these discoveries is generally declining, while finding and development costs are increasing. We believe that there remain areas of the United States, such as the Appalachian Basin and certain areas in our Southwest and Gulf Coast Areas that are underexplored or have not been fully explored and developed with the benefit of newly available exploration and production reservoir enhancement technology. Examples of such technology include advanced 3-D seismic processing, hydraulic reservoir fracture stimulation, advances in well logging and analysis, horizontal drilling and completion techniques, secondary and tertiary recovery practices, and automated remote well monitoring and control devices.

Oil and gas are commodities. The price that we receive for the natural gas we produce is largely a function of market supply and demand. Demand for natural gas in the United States increased dramatically during this decade; however, the current economic slowdown has reduced this demand over the second half of 2008 and is continuing into 2009. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Factors impacting the future supply balance are the growth in domestic gas production and the increase in the United States LNG import capacity. Significant LNG capacity increases have been announced which may allow for more LNG imports resulting in increased price volatility. A substantial or extended decline in oil and gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and our ability to access capital markets.

Realized oil and gas average prices increased from 2007 to 2008. As a result of narrowing excess worldwide capacity, weakness in the dollar, and continuing tension in the Middle East, oil reached a record price of $147.00 per Bbl in July 2008. However, rising crude oil supplies, the tightened credit markets and lower demand in the slowing U.S and global economies have caused recent oil prices to decline. Oil prices are expected to remain volatile. Although our average realized price (including all derivative settlements) received for oil and gas was $8.58 per mcfe in the year ended December 31, 2008, prices were bolstered by record oil prices in the first half of the year. In fourth quarter 2008, our average realized price (including all derivative settlements) declined to $6.86 per mcfe. In a trend that began in the fourth quarter of 2008 and has continued into 2009, the industry has experienced deteriorating basis differentials in the Midcontinent and West Texas areas primarily caused by an over-supply of gas in these regions.

Capital Budget for 2009

Our capital budget for 2009 is currently set at $700.0 million, excluding acquisitions. The 2009 capital budget is less than the 2008 capital spending levels due to lower expected operating cash flows resulting from declining oil and gas prices. For 2009, we expect our cash flow to fund our capital budget. As has been our historical practice, we will periodically review our capital expenditures throughout the year and adjust the budget based on commodity prices and drilling success.

Source of Our Revenues

We derive our revenues from the sale of oil and gas that is produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, quality, Btu content and transportation costs to market. Production volumes and the price of oil and gas are the primary factors affecting our revenues. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we use derivative instruments to hedge future sales prices on a significant portion of our gas and oil production. During 2008 and 2006, the use of derivative instruments prevented us from realizing the full benefit of upward price movements and may do so in future periods. Our average realized price calculations (including all derivative settlements) include both the effects of the settlement of derivative contracts that are accounted for as hedges and the settlement of derivative contracts that are not accounted for as hedges.

Principal Components of Our Cost Structure

Direct Operating Expenses. These are day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workovers expenses related to our oil and gas properties. These costs are expected to moderate in 2009 as we expect industry demand for these services to decline. Direct operating expenses also include stock-based compensation expense (non-cash) associated with equity grants of stock appreciation rights (SARs) and the amortization of restricted stock grants as part of employee compensation.

Production and Ad Valorem Taxes. Production taxes are paid on produced oil and gas based on a percentage of market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. Ad valorem taxes are taxes generally based on reserve values at the end of each year.

Exploration Expense. These are geological and geophysical costs, including payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes. Exploration expense includes stock-based compensation expense (non-cash) associated with equity grants of SARs and the amortization of restricted stock grants as part of employee compensation.

General and Administrative Expense. These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance are included in general and administrative expense. General and administrative expense includes stock-based compensation expense (non-cash) associated with equity grants of SARs and the amortization of restricted stock grants as part of employee compensation.

Abandonment and impairment of unproved properties. This category includes unproved property impairment and costs associated with lease expirations.

Interest. We typically finance a portion of our working capital requirements and acquisitions with borrowings under our bank credit facility and with our longer-term debt securities. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We will likely continue to incur significant interest expense as we continue to grow. We expect our 2009 capital budget to be funded primarily with internal cash flow.

Depreciation, Depletion and Amortization. This includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop gas and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This expense also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities.

Income Taxes. We are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs (IDC). We do pay some state income taxes where our IDC deductions do not exceed our taxable income or where state income taxes are determined on another basis. Currently, substantially all of our federal taxes are deferred; however, at some point, we anticipate using all of our net operating loss carryforwards and we will recognize current income tax expense and continue to recognize current tax expense as long as we are generating taxable income.

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Management s Discussion and Analysis of Income and Operations

Overview of 2008 Results

During 2008, we achieved the following results:

- Achieved 21% production growth and 19% reserve growth;
- Drilled 490 net wells with a 98% success rate;
- Continued expansion of emerging plays;
- Posted record financial results and maintained a strong balance sheet;
- Completed acquisitions of properties containing 95.6 Bcfe of proved reserves; and
- Completed $68.2 million of asset sales.

Our 2008 performance reflects another year of successfully executing our strategy of growth through drilling supplemented by complementary acquisitions. The business of exploring for, developing, and acquiring oil and gas is highly competitive and capital intensive. As in any commodity business, the costs associated with finding, acquiring, extracting, and financing our operations are critical to profitability and long-term value creation for stockholders. Generating meaningful growth while containing costs presents an ongoing challenge. During the recent period of historically high oil and gas prices, drilling service and operating costs generally increased due to increased competition for goods and services. Prices for oil and gas dramatically declined in the last half of 2008 and we are presently experiencing reductions in service costs which vary by region. We faced other challenges in 2008 including attracting and retaining qualified personnel, consummating and integrating acquisitions, accessing the capital markets to fund our growth on sufficiently favorable terms and introducing new oil and gas extraction technologies into new regions and projects such as the Pennsylvania Marcellus Shale. We have continued to expand and improve the technical staff through the hiring of additional experienced professionals. Our inventory of exploration and development prospects continues to be strong, providing new growth opportunities, greater diversification of technical risk and better efficiency.

Total revenues increased 53% in 2008 over the same period of 2007. This increase is due to higher production and higher realized oil and gas prices. Our 2008 production growth is due to the continued success of our drilling program and to acquisitions completed in 2006 and 2007. Average realized prices (including all derivative settlements) were 7% higher in 2008, although realized prices declined sharply in the last half of 2008. As discussed in Item 1A of this report, significant changes in oil and gas prices can have a material impact on our balance sheet and our results of operations, including the fair value of our derivatives.

All of our expenses have increased on both an absolute and per mcfe basis when compared to 2007, due to higher overall industry costs, higher compensation expense resulting from additional employees, increased salaries and higher levels of activity. While overall costs were higher, the rate of inflation experienced in our industry has moderated for some goods and services as commodity prices weakened. The availability of goods and services continues to be mixed, based on region and service company expertise. We continue to experience competition for technical and experienced personnel and overall compensation inflation in our industry has moderated. It is difficult for us to forecast price trends, supply, service or personnel availability, any of which, if changed in an adverse manner, would significantly impact both operating costs and capital expenditures. As we continue to have Marcellus wells shut-in waiting on pipeline and processing facilities and we continue to expand our Marcellus operating team to meet the needs of this developing asset, we expect to see continued upward pressure on our cost structure. The initial phase of the pipeline and processing infrastructure was completed in fourth quarter 2008 with additional expansions set for 2009 and later.

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Oil and Gas Sales, Production and Realized Price Calculations

Our oil and gas sales vary from year to year as a result of changes in realized commodity prices and production volumes. Hedges included in oil and gas sales reflect settlements on those derivatives that qualify for hedge accounting. Cash settlement of derivative contracts that are not accounted for as hedges are included in the income statement caption called Derivative fair value income (loss). Oil and gas sales increased 42% from 2007 due to a 21% increase in production and a 17% increase in realized prices. Oil and gas sales in 2007 increased 44% from 2006 due to a 22% increase in production and an 18% increase in realized prices. The following table illustrates the primary components of oil and gas sales for each of the last three years (in thousands):

	2008	2007	2006
Oil and Gas Sales			
Oil wellhead	$ 298,482	$ 226,686	$ 189,516
Oil hedges realized	(72,135)	(23,755)	(45,265)
Total oil revenue	$ 226,347	$ 202,931	$ 144,251
Gas wellhead	$ 923,160	$ 585,538	$ 466,099
Gas hedges realized	8,561	27,916	(47,916)
Total gas revenue	$ 931,721	$ 613,454	$ 418,183
Total NGL revenue	$ 68,492	$ 46,152	$ 36,705
Combined wellhead	$ 1,290,134	$ 858,376	$ 692,320
Combined hedges	(63,574)	4,161	(93,181)
Total oil and gas sales	$ 1,226,560	$ 862,537	$ 599,139

Our production continues to grow through drilling success as we place new wells into production and through additions from acquisitions, partially offset by the natural decline of our oil and gas wells and asset sales. For 2008, our production volumes increased 18% in our Appalachia Area, increased 22% in our Southwest Area and increased 61% in our Gulf Coast Area. For 2007, our production volumes increased 15% in our Appalachia Area, increased 28% in our Southwest Area and declined 17% in our Gulf Coast Area. For 2006, our production volumes increased 10% in our Appalachia Area, increased 29% in our Southwest Area and declined 36% in our Gulf Coast Area. Our production for each of the last three years is set forth in the following table:

	2008	2007	2006
Production			
Crude oil (bbls)	3,084,529	3,359,668	3,039,150
NGLs (bbls)	1,385,701	1,114,730	1,091,785
Natural gas (mcf)	114,323,436	89,594,626	70,712,770
Total (mcfe) [(a)]	141,144,816	116,441,014	95,498,380
Average daily production			
Crude oil (bbls)	8,428	9,205	8,326
NGLs (bbls)	3,786	3,054	2,991

Natural gas (mcf)	312,359	245,465	193,734
Total (mcfe) [(a)]	385,642	319,016	261,639

(a) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf.

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Our average realized price (including all derivative settlements) received for oil and gas during 2008 was $8.58 per mcfe compared to $8.02 per mcfe in 2007 and $6.80 per mcfe in 2006. Our average realized price (including all derivative settlements) calculation includes all cash settlements for derivatives, whether or not they qualify for hedge accounting. Average price calculations for each of the last three years is shown below:

	2008	2007	2006
Average Prices			
Average sales prices (wellhead):			
Crude oil (per bbl)	$ 96.77	$67.47	$62.36
NGLs (per bbl)	$ 49.43	$41.40	$33.62
Natural gas (per mcf)	$ 8.07	$ 6.54	$ 6.59
Total (per mcfe) [(a)]	$ 9.14	$ 7.37	$ 7.25
Average realized prices (including derivatives that qualify for hedge accounting):			
Crude oil (per bbl)	$ 73.38	$60.40	$47.46
NGLs (per bbl)	$ 49.43	$41.40	$33.62
Natural gas (per mcf)	$ 8.15	$ 6.85	$ 5.91
Total (per mcfe) [(a)]	$ 8.69	$ 7.41	$ 6.27
Average realized prices (including all derivative settlements):			
Crude oil (per bbl)	$ 68.20	$60.16	$47.46
NGLs (per bbl)	$ 49.43	$41.40	$33.62
Natural gas (per mcf)	$ 8.15	$ 7.66	$ 6.62
Total (per mcfe) [(a)]	$ 8.58	$ 8.02	$ 6.80
Average NYMEX prices [(b)]:			
Crude oil (per bbl)	$100.47	$72.34	$66.22
Natural gas (per mcf)	$ 8.91	$ 6.92	$ 7.26

(a) Oil and NGLs are converted at the rate of one barrel equals six mcf.

(b) Based on average of bid week prompt month prices.

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Derivative fair value income (loss) increased to a gain of $70.1 million in 2008 compared to a loss of $7.8 million in 2007 and a gain of $142.4 million in 2006. Some of our derivatives do not qualify for hedge accounting but are, to a degree, an economic offset to our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method whereby all realized and unrealized gains and losses related to these contracts are included in Derivative fair value income (loss) in the revenue section of our statement of operations. Mark-to-market accounting treatment creates volatility in our revenues as gains and losses from derivatives are included in total revenues and are not included in our balance sheet in Accumulated other comprehensive income (loss). As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Because oil and gas prices declined dramatically in the last half of 2008, our derivatives became comparatively more valuable. However, we expect these gains will be offset by lower wellhead revenues in the future. We have also entered into basis swap agreements to limit volatility caused by changing differentials between index and regional prices received. Basis swaps do not qualify for hedge accounting purposes and are marked to market. Hedge ineffectiveness, also included in Derivative fair value income (loss), is associated with our hedging contracts that qualify for hedge accounting under SFAS No. 133.

The following table presents information about the components of derivative fair value income (loss) for each of the years in the three-year period ended December 31, 2008 (in thousands):

	2008	2007	2006
Change in fair value of derivatives that do not qualify for hedge accounting [a]	$ 83,867	$ (78,769)	$ 86,491
Realized (loss) gain on settlements gas [b] [c]	(1,383)	71,098	49,939
Realized loss on settlements oil [b] [c]	(15,431)	(244)	
Hedge ineffectiveness realized [c]	1,386	968	
unrealized [a]	1,696	(820)	5,965
Derivative fair value income (loss)	$ 70,135	$ (7,767)	$ 142,395

(a) These amounts are unrealized and are not included in average sales price calculations.

(b) These amounts represent realized gains and losses on settled derivatives that do not qualify for hedge accounting.

(c) These settlements are included in

average realized price calculations (including all derivative settlements).

Other revenue increased in 2008 to $21.7 million compared to $5.0 million in 2007 and $856,000 in 2006. The 2008 period includes a $20.2 million gain on the sale of assets and a loss from equity method investments of $218,000. The 2007 period includes income from equity method investments of $974,000 and other miscellaneous income. The 2006 period includes income from equity method investments of $548,000.

Our costs have increased as we continue to grow. We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per mcfe, basis. The following presents information about certain of our expenses on a per mcfe basis for 2008, 2007 and 2006.

	Year Ended				Year Ended			
	2008	2007	Change	% Change	2007	2006	Change	% Change
Direct operating expense	$1.01	$0.92	$0.09	10%	$0.92	$0.85	$ 0.07	8%
Production and ad valorem tax expense	0.39	0.36	0.03	8%	0.36	0.38	(0.02)	5%
General and administrative expense	0.65	0.60	0.05	8%	0.60	0.52	0.08	15%
Interest expense	0.71	0.67	0.04	6%	0.67	0.58	0.09	15%
Depletion, depreciation and amortization expense	2.12	1.89	0.23	12%	1.89	1.62	0.27	17%

Direct operating expense was $142.4 million in 2008 compared to $107.5 million in 2007 and $81.3 million in 2006 due to higher oilfield service costs and higher volumes. Our operating expenses are increasing as we add new wells from development and acquisitions and maintain production from our existing properties. We incurred $9.9 million of workover costs in 2008 compared to $7.1 million in 2007 and $3.5 million in 2006. On a per mcfe basis, direct operating expenses for 2008 increased $0.09 or 10% from the same period of 2007 with the increase consisting primarily of higher workover costs ($0.01 per mcfe), higher personnel and related costs ($0.02 per mcfe) along with higher equipment leasing costs ($0.02 per mcfe) and higher overall industry costs. On a per mcfe basis, direct operating expenses for 2007 increased $0.07 or 8% from the same period of 2006 with the increase consisting primarily of higher workover costs ($0.02 per mcfe), higher water disposal costs ($0.02 per mcfe), higher well services and equipment costs ($0.04 per mcfe) and a $0.01 per mcfe increase in stock-based compensation. Stock-based compensation expense represents the amortization of our grants of restricted stock and SARs as part of employee compensation. The following table summarizes direct operating expenses per mcfe for 2008, 2007 and 2006:

	Year Ended				Year Ended			
	2008	2007	Change	% Change	2007	2006	Change	% Change
Lease operating expense	$ 0.92	$ 0.84	$ 0.08	10%	$ 0.84	$ 0.80	$ 0.04	5%
Workovers	0.07	0.06	0.01	17%	0.06	0.04	0.02	50%
Stock-based compensation (non-cash)	0.02	0.02		%	0.02	0.01	0.01	100%
Total direct operating expenses	$ 1.01	$ 0.92	$ 0.09	10%	$ 0.92	$ 0.85	$ 0.07	8%

Production and ad valorem taxes are paid based on market prices and not hedged prices. These costs were $55.2 million in 2008 compared to $42.4 million in 2007 and $36.4 million in 2006. On a per mcfe basis, production and ad valorem taxes increased to $0.39 in 2008 from $0.36 in the same period of 2007, primarily due to a 24% increase in pre-hedge prices. On a per mcfe basis, production and ad valorem taxes decreased to $0.36 in 2007 from $0.38 in 2006 with lower ad valorem taxes per mcfe due to lower property tax rates in Texas as a result of the new margin tax.

General and administrative expense was $92.3 million for 2008 compared to $69.7 million in 2007 and $49.9 million in 2006. The 2008 increase of $22.6 million when compared to the prior year is due primarily to higher salaries and benefits ($12.0 million) due to an increase in the number of employees (14%) and salary increases, higher stock-based compensation ($5.6 million), higher legal and professional fees ($921,000), an allowance for bad debt expense of $450,000 and higher office expenses, including rent and information technology. Our personnel costs continue to increase as we invest in our technical teams and other staffing to support our expansion into new regions particularly the Marcellus shall play in Appalachia. General and administrative expenses for 2007 increased $19.8 million from the same period of 2006 due primarily to higher salaries and benefits ($10.4 million), higher stock-based compensation ($4.0 million) and higher rent and office expense ($2.3 million). Stock-based compensation expense represents the amortization of our grants of restricted stock and SARs to our employees and directors as part of compensation. The following table summarizes general and administrative expenses per mcfe for 2008, 2007 and 2006:

	Year Ended				Year Ended			
	2008	2007	Change	% Change	2007	2006	Change	% Change
General and administrative	$ 0.48	$ 0.44	$ 0.04	9%	$ 0.44	$ 0.37	$ 0.07	19%
Stock-based compensation (non-cash)	0.17	0.16	0.01	6%	0.16	0.15	0.01	7%

Total general and administrative expenses	$ 0.65	$ 0.60	$ 0.05	8%	$ 0.60	$ 0.52	$ 0.08	15%

Interest expense was $99.7 million for 2008 compared to $77.7 million in 2007 and $55.8 million in 2006. Interest expense for 2008 increased $22.0 million from the same period of 2007 due to the refinancing of certain debt from floating rates to higher fixed rates along with higher overall debt balances. In September 2007, we issued $250.0 million of 7.5% senior subordinated notes due 2017, which added $13.9 million of additional interest costs in 2008. In May 2008, we issued $250.0 million of 7.25% senior subordinated notes due 2018, which added $11.8 million of interest costs in 2008. The proceeds from both issuances were used to retire bank debt which carried a lower interest rate. The note issuances were undertaken to better match the maturities of our debt with the life of our properties and to give us greater liquidity for the near term. Average debt outstanding on the bank credit facility for 2008 was $494.2 million compared to $417.6 million for 2007 and the weighted average interest rate was 4.4% in 2008 compared to 6.4% in 2007. Interest expense for 2007 increased $21.9 million from the same period of 2006 due to higher average debt balances and the refinancing of certain debt from short-term floating to longer-term fixed rates. The issuance of the 7.5% senior subordinated notes due 2017 in September 2007 added $4.8 million of interest costs in 2007. The issuance of the 7.5% senior subordinated notes in May 2006 added $9.1 million of interest expense in 2007. Average debt outstanding on the credit facility for 2007 was $417.6 million compared to $347.8 million in 2006. The weighted average interest rate was 6.4% in 2007 compared to 6.4% in the same period of 2006.

Depletion, depreciation and amortization (DD&A) was $299.8 million in 2008 compared to $220.6 million in 2007 and $154.5 million in 2006. The increase in 2008 compared to the same period of 2007 is due to a 21% increase in production and a 14% increase in depletion rates. On a per mcfe basis, DD&A increased to $2.12 in 2008 compared to $1.89 in 2007 and $1.62 in 2006. DD&A expense increased $66.1 million or 43% in 2007 compared to the same period of 2006 due to a 22% increase in production and a 16% increase in depletion rates. The increase in DD&A per mcfe is related to increasing drilling costs, higher acquisition costs and the mix of our production. The following table summarizes DD&A expense per mcfe for 2008, 2007 and 2006:

	Year Ended				Year Ended			
	2008	2007	Change	% Change	2007	2006	Change	% Change
Depletion and amortization	$ 1.99	$ 1.74	$ 0.25	14%	$ 1.74	$ 1.50	$ 0.24	16%
Depreciation	0.09	0.09		%	0.09	0.08	0.01	13%
Accretion and other	0.04	0.06	(0.02)	33%	0.06	0.04	0.02	50%
Total DD&A expense	$ 2.12	$ 1.89	$ 0.23	12%	$ 1.89	$ 1.62	$ 0.27	17%

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, exploration expense, abandonment and impairment of unproved properties and deferred compensation plan expenses. In 2008, stock-based compensation is a component of direct operating expense ($2.8 million), exploration expense ($4.1 million) and general and administrative expense ($23.8 million) for a total of $31.2 million. In 2007, stock-based compensation was a component of direct operating expense ($1.8 million), exploration expense ($3.5 million) and general and administrative expense ($18.2 million) for a total of $24.0 million. In 2006, stock-based compensation was a component of direct operating expense ($1.4 million), exploration expense ($3.1 million) and general and administrative expense ($14.3 million) for a total of $19.1 million. Stock-based compensation includes the amortization of restricted stock grants and SARs grants. These costs are increasing due to increasing grant date fair values and an increase in the number of grants on our increasing employee base.

Exploration expense was $67.7 million in 2008 compared to $43.3 million in 2007 and $44.1 million in 2006. The following table details our exploration-related expenses for 2008, 2007 and 2006 (in thousands):

	Year Ended				Year Ended			
	2008	2007	Change	% Change	2007	2006	Change	% Change
Dry hole expense	$ 13,371	$ 15,149	$ (1,778)	12%	$ 15,149	$ 15,084	$ 65	%
Seismic	30,645	10,933	19,712	180%	10,933	15,277	(4,344)	28%
Personnel expense	11,804	8,924	2,880	32%	8,924	6,917	2,007	29%
Stock-based compensation expense	4,130	3,473	657	19%	3,473	3,079	394	13%
Delay rentals and other	7,740	4,866	2,874	59%	4,866	3,731	1,135	30%
Total exploration expense	$ 67,690	$ 43,345	$ 24,345	56%	$ 43,345	$ 44,088	$ (743)	2%

Abandonment and impairment of unproved properties was $47.9 million in 2008 compared to $6.8 million in 2007 and $257,000 in 2006. This increase is primarily due to the significant increase in lease acquisition costs over the past three years and increased leasing activity in exploratory areas that require several years to delineate. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, more leasehold impairments and abandonments will be recorded.

Deferred compensation plan expense was a gain of $24.7 million in 2008 compared to a loss of $28.3 million in 2007 and a loss of $6.9 million in 2006. This non-cash expense relates to the increase or decrease in value of the vested Range common stock held in our deferred compensation plan. The deferred compensation liability is adjusted to fair value by a charge or a credit to deferred compensation plan expense. The year ended 2008 decreased $53.0 million from the same period of 2007 due to a decline in our stock price, which decreased from $51.36 at December 31, 2007 to $34.39 at December 31, 2008. During the same period of the prior year, our stock price increased from $27.46 at December 31, 2006 to $51.36 at December 31, 2007. From December 31, 2005 to December 31, 2006 our stock price increased from $26.34 to $27.46.

Income tax expense was $196.4 million in 2008 compared to $98.8 million in 2007 and $121.8 million in 2006. The 2008 increase reflects a 104% increase in income from continuing operations before taxes compared to the same period of 2007. 2008 provided for tax expenses at an effective rate of 36.2% compared to an effective rate of 37.2% in the same period of 2007. For 2008, current income taxes of $4.3 million include state income taxes of $3.3 million and $1.0 million of federal income taxes. The effective tax rate on continuing operations was different than the statutory rate of 35% due to state income taxes and $2.0 million of additional tax benefit related to discrete items. Income tax expense for 2007 decreased to $98.8 million, reflecting a 16% decrease in income from continuing operations before taxes compared to the same period of 2006. The year ended December 31, 2007 provided for tax expense at an effective rate of 37.2% compared to an effective rate of 38.6% in the same period of 2006. For the year ended December 31, 2007, current income taxes includes state income taxes of $449,000 and a benefit of $129,000 of federal income taxes. We expect our effective tax rate to be approximately 37% for 2009.

Discontinued operations in 2007 include the operating results related to our Gulf of Mexico properties and Austin Chalk properties sold in first quarter 2007.

Management s Discussion and Analysis of Financial Condition, Cash Flows and Liquidity

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a bank credit facility with both uncommitted and committed availability, asset sales and access to the debt and equity capital markets. The debt and equity capital markets have recently exhibited adverse conditions. Continued volatility in the capital markets may increase costs associated with issuing debt due to increased spreads over relevant interest rate benchmarks and affect our ability to access those markets. At this point, we do not believe our liquidity has been materially affected by the recent events in the global financial markets and we do not expect our liquidity to be materially impacted in the near future. We will continue to monitor our liquidity and the credit markets. Additionally, we will continue to monitor events and circumstances surrounding each of the twenty-six lenders in our bank credit facility. To date we have experienced no disruptions in our ability to access the bank credit facility. However, we cannot predict with any certainty the impact to us of any further disruption in the credit environment. For additional information, see Risk Factors-*Difficult Conditions in the global capital markets and the economy generally may materially adversely affect our business and results of operations* in Item 1A of this report. In December 2008, we elected to utilize the expansion option under our bank credit facility and increased our credit facility commitment by $250.0 million, which makes the current bank commitment $1.25 billion. At December 31, 2008, our borrowing base was $1.5 billion. The borrowing base represents the amount approved by the bank group than can be borrowed based on our assets while the bank commitment (or facility amount) is the amount the banks have committed to fund pursuant to the credit agreement. We currently believe our maximum credit facility borrowing capacity exceeds our current borrowing base and, based on current circumstances, is sufficient to absorb a decline in commodity prices or any changes in bank lending practices.

During 2008, our net cash provided from continuing operations of $824.8 million, proceeds from our April 2008 common stock offering of $282.2 million, proceeds from our May 2008 note offering of $250.0 million, proceeds from the sale of assets of $68.2 million and bank borrowings were used to fund $1.8 billion of capital expenditures (including acquisitions and equity investments). At December 31, 2008, we had $753,000 in cash and total assets of $5.6 billion. Our debt to capitalization ratio was 42% at December 31, 2008 compared to 40% at December 31, 2007. As of December 31, 2008 and 2007, our total capitalization was as follows (in thousands):

	2008	2007
Bank debt	$ 693,000	$ 303,500
Senior subordinated notes and other	1,097,668	847,158
Total debt	1,790,668	1,150,658
Stockholders equity	2,457,833	1,728,022
Total capitalization	$ 4,248,501	$ 2,878,680
Debt to capitalization ratio	42%	40%

Long-term debt at December 31, 2008 totaled $1.8 billion, including $693.0 million of bank credit facility debt and $1.1 billion of senior subordinated notes. Our available committed borrowing capacity at December 31, 2008 was $557.0 million. Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves that are typical in the oil and gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We currently believe that net cash generated from operating activities and unused committed borrowing capacity under the bank credit facility combined with our oil and gas price hedges currently in place will be adequate to satisfy near-term financial obligations and liquidity needs. However, long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. A material drop in oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

Our opinions concerning liquidity and our ability to avail ourselves in the future of the financing options mentioned in the above forward-looking statements are based on currently available information. If this information proves to be inaccurate, future availability of financing may be adversely affected. Factors that affect the availability of financing include our performance, the state of the worldwide debt and equity markets, investor perceptions and expectations of past and future performance, the global financial climate and, in particular, with respect to borrowings, the level of our working capital or outstanding debt and credit ratings by rating agencies. For additional information, see Risk Factors-*Difficult Conditions in the global capital markets and the economy generally may materially adversely affect our business and results of operations* in Item 1A of this report.

Credit Arrangements

We maintain a $1.25 billion revolving credit facility, which we refer to as our bank debt or our bank credit facility. The bank credit facility is secured by substantially all of our assets and matures on October 25, 2012. Availability under the bank credit facility is subject to a borrowing base set by the lenders semi-annually with an option to set more often in certain circumstances. The borrowing base is dependent on a number of factors, primarily the lenders assessment of future cash flows. Redeterminations of the borrowing base require approval of 2/3rds of the lenders; increases require unanimous approval. At February 19, 2009, the bank credit facility had a $1.5 billion borrowing base and a $1.25 billion facility amount. Remaining credit availability is $442.0 million on February 19, 2009. Our bank group is comprised of twenty-six commercial banks, with no one bank holding more than 5.0% of the bank credit facility. We believe our large number of banks and relatively low commitment hold levels allows for sufficient lending capacity should we elect to increase our $1.25 billion commitment up to the $1.5 billion borrowing base and also allows for flexibility should there be additional consolidation within the banking sector. In December 2008, we elected to utilize the expansion option under the bank credit facility and increased our credit facility commitment by $250.0 million, which made the current commitment $1.25 billion.

Our bank debt and our subordinated notes impose limitations on the payment of dividends and other restricted payments (as defined under the debt agreements for our bank debt and our subordinated notes). The debt agreements also contain customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2008.

Cash Flow

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivatives. Our cash flows from operations also are impacted by changes in working capital. We sell substantially all of our oil and gas production at the wellhead under floating market contracts. However, we generally hedge a substantial, but varying portion of our anticipated future oil and gas production for the next 12 to 24 months. Any payments due to counterparties under our derivative contracts should ultimately be funded by prices received from the sale of our production. Production receipts, however, often lag payments to the counterparties. Any interim cash needs are funded by borrowing under the credit facility. As of December 31, 2008, we have entered into hedging agreements covering 97.8 Bcfe for 2009.

Net cash provided from continuing operations in 2008 was $824.8 million, compared to $632.1 million in 2007 and $441.5 million in 2006. The increase in cash provided by operating activities from 2007 to 2008 and from 2006 to 2007 was primarily due to increased production from acquisitions and development activity and higher price realizations. Cash provided from operations is largely dependent upon prices received for oil and gas production. As of February 19, 2009, we have hedged approximately 77% of our 2009 projected production. Net cash provided from continuing operations is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in the consolidated statement of cash flows) for 2008 was a positive $20.2 million compared to a negative $13.0 million in 2007 and a positive $20.3 million in 2006.

Net cash used in investing activities in 2008 was $1.7 billion compared to $1.0 billion in 2007 and $911.7 million in 2006. In 2008, we spent $881.9 million on additions to oil and gas properties, $834.8 million on acquisitions and $44.2 million on equity method investments and other assets. Acquisitions in 2008 include the purchase of producing and non-producing Barnett Shale properties and Marcellus Shale leasehold. In 2007, we spent $782.4 million in additions to oil and gas properties, $336.5 million on acquisitions and $94.7 million on equity method investments. Acquisitions in 2007 included acquiring additional interests in the Nora field of Virginia where we entered into a joint development plan with Equitable Resources, Inc. Also in 2007, we recognized proceeds of $234.3 million from the sale of assets. The 2006 period included $487.2 million in additions to oil and gas properties and $360.1 million of acquisitions. Acquisitions in 2006 include the purchase of Stroud Energy, Inc., which had operations in the Barnett Shale.

Net cash provided from financing activities in 2008 was $903.7 million, compared to $379.9 million in 2007 and $429.4 million in 2006. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. During 2008, we received proceeds of $250.0 million from the issuance of our 7.25% senior subordinated notes and proceeds of $282.2 million from a common stock offering. During 2007, we received proceeds of $250.0 million from the issuance of our 7.5% senior subordinated notes due 2017 and proceeds of $280.4 million from a common stock offering. During 2006, we received proceeds of $249.5 million from the issuance of our 7.5% senior subordinated notes due 2016. In 2008, our board of directors approved a share repurchase program authorizing the purchase of up to $10.0 million of our common stock. During 2008, we expended $3.2 million to acquire 78,400 shares.

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of oil and gas properties, repayment of principal and interest on outstanding debt and payment of dividends. During 2008, $930.1 million of capital was expended on drilling projects. Also in 2008, $845.5 million was expended on acquisitions of additional interests in producing properties and unproved acreage. The capital program, excluding acquisitions, was funded by net cash flow from operations, proceeds from asset sales, debt and equity offerings and borrowings under our bank credit facility. Our capital expenditure budget for 2009 is currently set at $700.0 million, excluding acquisitions. Development and exploration activities are highly discretionary, and, for the foreseeable future, we expect such activities to be maintained at levels equal to internal cash flow. To the extent capital requirements exceed internal cash flow and proceeds from asset sales, debt or equity may be issued to fund these requirements. We currently believe we have sufficient liquidity and cash flow to meet our obligations for the next twelve months; however, a continued drop in oil and gas prices or a reduction in production or reserves could adversely affect our ability to fund capital expenditures and meet our financial obligations. We monitor our capital expenditures on a regular basis, adjusting the amount up or down and also between our operating regions, depending on commodity prices, cash flow and projected returns. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

Cash Dividend Payments

The amount of future dividends is subject to declaration by the Board of Directors and primarily depends on earnings and capital expenditures. In 2008, we paid $24.6 million in dividends to our common shareholders ($0.04 per share in each quarter). In 2007, we paid $19.1 million in dividends to our common shareholders ($0.04 per share in the fourth quarter and $0.03 per share in the third, second and first quarters). In 2006, we paid $12.2 million in dividends to our common stockholders ($0.03 per share in the fourth quarter and $0.02 per share in the third, second and first quarters).

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations, other liabilities and transportation commitments. As of December 31, 2008, we do not have any capital leases nor have we entered into any material long-term contracts for equipment. As of December 31, 2008, we do not have any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed the debt of any unrelated party. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2008. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2008 reflects accrued interest payable on our bank debt of $779,000 which is payable in first quarter 2009. We expect to make interest payments of $9.6 million per year on our 6.375% senior subordinated notes, $14.8 million per year on our 7.375% senior subordinated notes, $18.8 million per year on our 7.5% senior subordinated notes due 2016, $18.8 million per year on our 7.5% senior subordinated notes due 2017 and $18.1 million per year on our 7.25% senior subordinated notes.

The following summarizes our contractual financial obligations at December 31, 2008 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our bank credit facility and proceeds from asset sales.

	Payment due by period				
	2009	2010 and 2011	2012 and 2013	Thereafter	Total
			(in thousands)		
Bank debt due 2012	$	$	$ 693,000 [a]	$	$ 693,000
7.375% senior subordinated notes due 2013			200,000		200,000
6.375% senior subordinated notes due 2015				150,000	150,000
7.5% senior subordinated notes due 2016				250,000	250,000
7.5% senior subordinated notes due 2017				250,000	250,000
7.25% senior subordinated notes due 2018				250,000	250,000
Other debt			105		105
Operating leases	10,284	19,479	9,585	9,257	48,605
Drilling rig commitments	26,850	116,800	31,685		175,335
Transportation commitments	17,369	32,995	25,861	69,145	145,370
Seismic agreements	900	900			1,800
Derivative obligations [b]	10				10
Asset retirement obligation liability [c]	2,055	10,197	1,233	69,972	83,457
Total contractual obligations [d]	$ 57,468	$ 180,371	$ 961,469	$ 1,048,374	$ 2,247,682

(a) Due at termination date of our bank credit facility. We expect to renew our bank credit facility, but there is no assurance that can be accomplished. Interest paid on our bank credit facility would be approximately $20.1 million each year assuming no change in the interest rate or outstanding balance.

(b) Derivative obligations represent net open derivative contracts valued as of December 31, 2008. While such payments will be funded by higher prices received from the sale of our production, production receipts may be received after our payments to counterparties, which can result in borrowings under our bank credit facility.

(c) The ultimate settlement and timing cannot be precisely determined in advance.

(d) This table excludes the liability for the deferred compensation plans since these obligations will be funded with existing plan assets.

In addition to the amounts included in the above table, we have contracted with a pipeline company through 2017 to deliver natural gas production volumes in Appalachia from certain Marcellus Shale wells. The agreement calls for incremental increases over the initial 40,000 Mmbtu per day. These increases, which are contingent on certain pipeline modifications, are for 30,000 Mmbtu per day in March 2009, 30,000 Mmbtu per day in October 2009, 30,000 Mmbtu per day March 2010 and an additional 20,000 Mmbtu per day for July 2010 for a total increase of 110,000 Mmbtu per day.

Delivery Commitments

Under a sales agreement with Enterprise Products Operating, LLC, we have an obligation to deliver 30,000 Mmbtu per day of volume at various delivery points within the Barnett Shale basin. The contract, which began in 2008, extends for five years ending March 2013. As of December 31, 2008, remaining volumes to be delivered under this commitment are approximately 46.5 bcf.

Hedging Oil and Gas Prices

We use commodity-based derivative contracts to manage exposure to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. These contracts consist of collars and fixed price swaps. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. While there is a risk that the financial benefit of rising oil and gas prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets.

At December 31, 2008, swaps were in place covering 25.6 Bcf of gas at prices averaging $8.38 per mcf. We also had collars covering 54.8 Bcf of gas at weighted average floor and cap prices of $8.28 to $9.27 and 2.9 million barrels of oil at weighted average floor and cap prices of $64.01 to $76.00. Their fair value, represented by the estimated amount that would be realized or payable on termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a pretax gain of $214.2 million at December 31, 2008. The contracts expire monthly through December 2009.

At December 31, 2008, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2009	Swaps	70,000 Mmbtu/day	$8.38
2009	Collars	150,000 Mmbtu/day	$8.28 - $9.27
Crude Oil			
2009	Collars	8,000 bbl/day	$64.01 - $76.00

In addition to the swaps and collars above, we have entered into basis swap agreements. The price we receive for our production can be less than NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax gain of $12.4 million at December 31, 2008.

Interest Rates

At December 31, 2008, we had $1.8 billion of debt outstanding. Of this amount, $1.1 billion bears interest at fixed rates averaging 7.3%. Bank debt totaling $693.0 million bears interest at floating rates, which averaged 2.9% at year-end 2008. The 30-day LIBOR rate on December 31, 2008 was 0.4%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2008 would cost us approximately $6.9 million in additional annual interest expense.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resource position, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments as described above under cash contractual obligations.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. In a trend that began in the fourth quarter of 2008 and has continued into 2009, the industry has experienced deteriorating basis differentials in the Mid-Continent and West Texas areas primarily caused by an over-supply of gas in these regions. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and accelerated through the middle of 2008, commodity prices for oil and gas increased significantly. The higher prices have led to increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs but also on our capital costs. Due to the decline in commodity prices in the last half of 2008, we expect these costs to moderate in 2009.

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The following table indicates the average oil and gas prices received over the last five years and quarterly for 2008, 2007 and 2006. Average price calculations exclude all derivative settlements whether or not they qualify for hedge accounting. Oil is converted to natural gas equivalent at the rate of one barrel equals six mcfe.

	Average Sales Prices (Wellhead)			Average NYMEX Prices [a]	
	Crude Oil (Per bbl)	Natural Gas (Per mcf)	Equivalent Mcf (Per mcfe)	Crude Oil (Per bbl)	Natural Gas (Per mcf)
Annual					
2008	$ 96.77	$ 8.07	$ 9.14	$100.47	$ 8.91
2007	67.47	6.54	7.37	72.34	6.92
2006	62.36	6.59	7.25	66.22	7.26
2005	53.30	8.00	7.99	56.56	8.55
2004	39.20	5.80	5.79	41.41	6.09
Quarterly					
2008					
First	$ 94.65	$ 7.85	$ 8.96	$ 97.90	$ 8.07
Second	120.27	10.09	11.48	123.98	10.80
Third	113.91	9.72	10.90	117.83	10.08
Fourth	55.09	4.86	5.43	58.79	6.82
2007					
First	$ 56.01	$ 6.41	$ 6.88	$ 58.27	$ 6.96
Second	62.20	6.95	7.57	65.03	7.56
Third	70.51	5.97	7.01	75.38	6.13
Fourth	82.12	6.80	7.94	90.68	7.03
2006					
First	$ 59.74	$ 8.33	$ 8.41	$ 63.48	$ 9.07
Second	65.36	6.28	7.17	70.70	6.82
Third	64.53	6.12	7.00	70.48	6.53
Fourth	59.80	5.91	6.58	60.21	6.62

(a) Based on average of bid week prompt month prices.

Debt Ratings

We receive debt credit ratings from Standard & Poor s Ratings Group, Inc. (S&P) and Moody s Investor Services, Inc. (Moody s), which are subject to regular reviews. S&P s rating for us is BB with a stable outlook. Moody s rating for us is Ba2 with a stable outlook. We believe that S&P and Moody s consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels, asset, and proved reserve mix. We also believe that the rating agencies take into consideration our size, corporate structure, the complexity of our capital structure and organization, and history of how we have chosen to finance our growth. We believe that our simple balance sheet, singular line of business, and practice of funding our growth with a balanced mix of long-term debt and common equity positively impact our ratings. In addition to qualitative and quantitative factors unique to Range, we believe that the rating agencies consider various macro-economic factors such as the projected future price of oil and gas, trends in industry service costs, and global supply and demand for energy. Based upon the factors influencing our credit ratings which are within our control, we are not currently aware of any reason why our credit rating would change materially from the present ratings. A reduction in our debt ratings could negatively impact our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

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Management s Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. Actual results could differ from the estimates and assumptions used.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

Oil and Gas Properties

We use the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration drilling costs are expensed and can have a significant effect on reported operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and gas reserves as estimated by our engineers and reviewed by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in the depletion rates used by us. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Senior Vice President of Reservoir Engineering who reports directly to our President. To further ensure the reliability of our reserve estimates, we engage independent petroleum consultants to review our estimates of proved reserves. Independent petroleum consultants reviewed 87% of our reserves in 2008 compared to 86% in 2007 and 2006. Historical variances between our reserve estimates and the aggregate estimates of our consultants have been less than 5%. The reserves included in this report are those reserves estimated by our employees.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property s total cost, proved reserve revisions result in a change in timing when depletion expense is recognized. Downward revisions of proved reserves result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Based on proved reserves at December 31, 2008, we estimate that a 1% change in proved reserves would increase or decrease 2009 depletion expense by approximately $3.0 million (assuming a 10% production increase). Estimated reserves are used as the basis for calculating the expected future cash flows from a property, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to oil and gas producing activities and reserve quantities in Note 18 to our consolidated financial statements. Changes in the estimated reserves are considered in estimates for accounting purposes and are reflected on a prospective basis.

We monitor our long-lived assets recorded in property, plant and equipment in our consolidated balance sheet to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and gas sales prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustments to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts or environmental regulations. All of these factors must be considered when testing a property s carrying value for impairment. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop proved reserves. Expected future net cash inflow from the sale of production of reserves is calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, the economic and regulatory climates. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows) and the carrying value of the asset. We cannot predict whether impairment charges may be required in the future. Our historical impairment of producing properties has been $74.9 million in 2006, $3.6 million in 2004, $31.1 million in 2001, $29.9 million in 1999 and $214.7 million in 1998. We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome.

We are required to develop estimates of fair value to allocate purchase prices paid to acquire businesses to the assets acquired and liabilities assumed under the purchase method of accounting. The purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. We use all available information to make these fair value determinations. See Note 3 to our consolidated financial statements for information on these acquisitions.

We adhere to the Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leaseholds. The costs are capitalized and periodically evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider a combination of time, geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $766.2 million in 2008 compared to $271.4 million in 2007 and $226.3 million in 2006. We have recorded abandonment and impairment expense related to unproved properties of $47.9 million in 2008 compared to $6.8 million in 2007 and $257,000 in 2006.

Oil and Gas Derivatives

We enter into derivative contracts to mitigate our exposure to commodity price risk associated with future oil and gas production. These contracts have historically consisted of options, in the form of collars, and fixed price swaps. Every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. We record these values on our balance sheet as either Unrealized derivative gains or Unrealized derivative losses.

If a derivative qualifies for cash flow hedge accounting, changes in the fair value of effective portion are recorded as a component of Accumulated other comprehensive income (loss) on the balance sheet, which is later transferred to earnings when the hedged transaction occurs. Realized gains or losses of derivatives that qualify for hedge accounting are included in oil and gas sales in our statement of operations. Oil and gas sales include $63.6 million of losses in 2008 compared to gains of $4.2 million in 2007 and losses of $93.2 million in 2006.

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Some of our derivatives do not qualify for hedge accounting or are not designated as hedges but are, to a degree, an economic offset of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Under this method, all unrealized and realized gains and losses related to these contracts are recognized in our consolidated statement of operations under the caption Derivative fair value income (loss). As of December 31, 2008, derivatives for 40.1 Bcfe no longer qualify or are not designated for hedge accounting.

We have also entered into basis swap agreements which do not qualify for hedge accounting and are also marked to market. The price we receive for our gas production can be less than the NYMEX price because of adjustments for delivery location, or basis, relative quality and other factors; therefore, we have entered into basis swap agreement that effectively fix our basis adjustments for a portion of our production.

On January 1, 2008, we adopted SFAS No. 157 for those financial assets and liabilities recognized or disclosed at fair value in our consolidated financial statements on a recurring basis. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. It does not require us to make any new fair value measurements, but rather establishes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value. Derivative assets and liabilities recorded at fair value are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels-defined by SFAS No. 157 and directly related to the amount of subjectivity associated with the inputs to fair valuation of these assets and liabilities are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date.

Level 2 Pricing inputs are other than quoted prices in active markets included in Level 1, which are directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry standard models that consider assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for underlying instruments, as well as other relevant economics measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data, which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. At December 31, 2008, we have no Level 3 measurements.

For Range, the primary impact from the adoption of SFAS No. 157 at January 1, 2008 related to the fair value measurement of our marketable securities held in our deferred compensation plan and the fair value measurement of our derivative instruments. FSP FAS 157-2, Effective Date of FASB Statement No. 157, deferred the effective date of SFAS No. 157 for one year for certain non-financial asset and non-financial liabilities, which for us includes the initial measurement of asset retirement obligations. We will adopt SFAS 157 for non-financial assets and liabilities effective January 1, 2009 and it is not expected to have a significant impact on our reported financial position or earnings.

We use a market approach for our value measurements. The assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our trading securities in Level 1 are exchange traded and measured at fair value with a market approach using December 31, 2008 market values. Our commodity derivatives in Level 2 are measured using third-party pricing services which have been corroborated with data from active markets or broker quotes. Our exposure is diversified among major investment grade financial institutions and we have master netting agreements with the majority of our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative counterparties include twelve financial institutions, ten of which are secured lenders in our bank credit facility. We have two counterparties that are not part of our bank group and three counterparties in our bank group with no master netting agreements. Mitsui & Co. and J. Aron & Company are the two counterparties not in our bank group. At December 31, 2008, our net derivative receivable includes a receivable from J. Aron & Company of $987,000 and a receivable from Mitsui & Co. of $18.0 million. In accordance with SFAS No. 157, counterparty credit risk is considered when determining the fair value of our derivative contracts. While our counterparties are major investment grade financial institutions, the fair value of our derivative contracts have been adjusted to account for the risk of non-performance by the counterparty, which was immaterial.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore land at the end of oil and gas production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation, (ARO), a corresponding adjustment is made to the oil and gas property balance. For example, as we analyze actual plugging and abandonment information, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. During 2008, we increased our existing estimated asset retirement obligation by $2.4 million or approximately 3% of the asset retirement obligation at December 31, 2007. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in our consolidated statement of operations. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates. We do not provide for a market risk premium because a reliable estimate cannot be determined.

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit, which can take years to complete, and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized.

In determining deferred tax liabilities, accounting rules require accumulated other comprehensive income to be considered, even though such income or loss has not yet been earned. At year-end 2008, deferred tax liabilities exceeded deferred tax assets by $816.4 million, with $44.7 million of deferred tax liabilities related to unrealized hedging gains included in accumulated other comprehensive income. At year-end 2007, deferred tax liabilities exceeded deferred tax assets by $563.9 million, with $16.3 million of deferred tax assets related to unrealized hedging losses included in OCI.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. Although we continue to monitor all contingencies closely, particularly our outstanding litigation, we currently have no material accruals for contingent liabilities.

Revenue Recognition

Oil, gas and natural gas liquids are recognized when the products are sold and delivery to the purchaser has occurred. We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of gas produced. We recognize the cost of revenues, such as transportation and compression expense, as a reduction of revenue.

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Stock-based Compensation

We adopted SFAS No. 123(R) on January 1, 2006. We previously accounted for stock awards under the recognition and measurement principles of ABB No. 25, Accounting for Stock Issued to Employees, and related interpretations. Prior to January 1, 2006 stock-based employee compensation for restricted stock was reflected in our statement of operations, but no compensation expense was recognized for stock options granted with an exercise price equal to the market value of the underlying common stock on the date of grant.

We adopted SFAS No. 123(R) using the modified prospective transition method. Under the modified prospective application method, we have applied the standards to awards made after adoption. Additionally, compensation cost for the unvested portion of stock awards outstanding as of January 1, 2006 has been recognized as compensation expense as the requisite service is rendered after January 1, 2006. We recognize stock-based compensation on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant.

The Compensation Committee grants restricted stock to certain employees and to non-employee directors of the Board of Directors as part of their compensation. Compensation expense is recognized over the balance of the vesting period, which is typically three years for employee grants and immediate vesting for non-employee directors. All restricted shares that are granted are placed in the deferred compensation plan. All vested restricted stock held in our deferred compensation plan is marked-to-market each reporting period based on the market value of our stock. This mark-to-market is presented in the caption deferred compensation plan in our statement of operations. See additional information in Note 12.

The fair value of stock options and stock-settled SARs is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The model employs various assumptions, based on management s best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of grant.

Accounting Standards Not Yet Adopted

In June 2008, the FASB issued Staff Position No. EITF 03-6-1 Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities, (FSP EITF 03-6-1) which provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. FSP EITF 03-6-1 is effective for us January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) will be adjusted retroactively to conform to its provisions. Early application of FSP EITF 03-6-1 is not permitted. Although restricted stock awards meet this definition, we do not expect the application of FSP 03-6-1 to have a significant impact on our reported earnings per share.

In March 2008, the FASB issued SFAS No. 161, Disclosure about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 (SFAS No. 161). SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why an entity uses derivative instruments; (ii) how derivative instruments and related hedge items are accounted for under SFAS No. 133 and its related interpretations; and (iii) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. SFAS No. 161 is effective for us January 1, 2009 and will only impact future disclosure about our derivative instruments and hedging activities.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) replaces SFAS No. 141. The statement retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in the purchase accounting. It changes the recognition of assets acquired and liabilities assumed arising from contingencies, requires the capitalization of in-process research and development at fair value, and requires the expensing of acquisition-related costs as incurred. The statement will apply prospectively to business combinations occurring in our fiscal year beginning January 1, 2009. The effect of adopting SFAS No. 141(R) is not expected to have an effect on our reported financial position or earnings.

ITEM 7A. QUANTITIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are US dollar denominated.

Financial Market Risk

The debt and equity markets have recently exhibited adverse conditions. The unprecedented volatility and upheaval in the capital markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and may affect our ability to access those markets. At this point, we do not believe our liquidity has been materially affected by the recent events in the global markets and we do not expect our liquidity to be materially impacted in the near future. We will continue to monitor our liquidity and the capital markets. Additionally, we will continue to monitor events and circumstances surrounding each of our twenty-six lenders in the bank credit facility. See also Item 1A. Risk Factors.

Market Risk

Our major market risk is exposure to oil and gas prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Oil and gas prices have been volatile and unpredictable for many years.

Commodity Price Risk

We periodically enter into derivative arrangements with respect to our oil and gas production. These arrangements are intended to reduce the impact of oil and gas price fluctuations. Certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program also includes collars, which establish a minimum floor price and a predetermined ceiling price. As of December 31, 2008, we had oil and gas swaps in place covering 25.6 Bcf of gas. We also had collars covering 54.8 Bcf of gas and 2.9 million barrels of oil. These contracts expire monthly through December 2009. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2008, approximated a net unrealized pre-tax gain of $214.2 million.

At December 31, 2008, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value (in thousands)
Natural Gas				
2009	Swaps	70,000 Mmbtu/day	$8.38	$ 57,280
2009	Collars	150,000 Mmbtu/day	$8.28 - $9.27	$121,781
Crude Oil				
2009	Collars	8,000 bbl/day	$64.01 - $76.00	$ 35,166

Other Commodity Risk

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the collars and swaps above, we have entered into basis swap agreements. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net realized pre-tax gain of $12.4 million at December 31, 2008.

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The following table shows the fair value of our swaps and collars and the hypothetical change in fair value that would result from a 10% change in commodities prices at December 31, 2008. The hypothetical change in fair value would be a gain or loss depending on whether prices increase or decrease (in thousands):

	Fair Value	Hypothetical Change in Fair Value
Swaps	$ 57,280	$15,000
Collars	$156,947	$45,000

Our commodity-based contracts expose us to the credit-risk of non-performance by the counterparty to the contracts. Our exposure is diversified among major investment grade financial institutions and we have master netting agreements with the majority of our counterparties that provide for offsetting payables against receivables from separate derivative contracts. Our derivative counterparties include twelve financial institutions, ten of which are secured lenders in our bank credit facility. We have two counterparties that are not part of our bank group and three counterparties in our bank group with no master netting agreement. Mitsui & Co. and J. Aron & Company are the two counterparties not in our bank group. At December 31, 2008, our net derivative receivable includes a receivable from J. Aron & Company of $987,000 and a receivable from Mitsui & Co. of $18.0 million. In accordance with SFAS No. 157, counterparty credit risk is considered when determining the fair value of our derivative contracts. While counterparties are major investment grade financial institutions, the fair value of our derivative contracts have been adjusted to account for the risk of non-performance by counterparty, which was immaterial.

Interest Rate Risk

We are exposed to interest rate risk on our bank debt. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest costs, interest rate volatility and financing risk. This is accomplished through a mix of fixed rate senior subordinated debt and variable rate bank debt.

At December 31, 2008, we had $1.8 billion of debt outstanding. Of this amount, $1.1 billion bears interest at a fixed rate averaging 7.3%. Bank debt totaling $693.0 million bears interest at floating rates, which was 2.9% on that date. On December 31, 2008, the 30-day LIBOR rate was 0.4%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2008 would cost us approximately $6.9 million in additional annual interest expense.

The fair value of our subordinated debt is based on year-end quoted market prices. The following table presents information on these fair values (in thousands):

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Subordinated Notes due 2013	$ 197,968	$ 181,500
(The interest rate is fixed at a rate of 7.375%)		
Senior Subordinated Notes due 2015	150,000	121,500
(The interest rate is fixed at a rate of 6.375%)		
Senior Subordinated Notes due 2016	249,595	212,500
(The interest rate is fixed at a rate of 7.5%)		
Senior Subordinated Notes due 2017	250,000	209,375
(The interest rate is fixed at a rate of 7.5%)		
Senior Subordinated Notes due 2018	250,000	206,250

(The interest rate is fixed at a rate of 7.25%)

	$ 1,097,563	$ 931,125

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

For financial statements required by Item 8, see Item 15 in Part IV of this report.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2008.

Management s Annual Report on Internal Control over Financial Reporting and Attestation Report of Registered Public Accounting Firm. Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management s assessment of the design and effectiveness of its internal controls as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2008. Ernst & Young LLP, our registered public accountants, also attested to, and reported on, management s assessment of the effectiveness of internal control over financial reporting. Management s report and the independent public accounting firm s attestation report are included in our 2008 Financial Statements in Item 15 under the captions Management s Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting, and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during fourth quarter 2008 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The officers and directors are listed below with a description of their experience and certain other information. Each director was elected for a one-year term at the 2008 annual stockholders meeting. Officers are appointed by our board of directors.

	Age	Office Held Since	Position
Charles L. Blackburn	81	2003	Director
Anthony V. Dub	59	1995	Director
V. Richard Eales	72	2001	Lead Independent Director
James M. Funk	59	2008	Director
Allen Finkelson	62	1994	Director
Jonathan S. Linker	60	2002	Director
Kevin S. McCarthy	49	2005	Director
John H. Pinkerton	54	1990	Director, Chairman of the Board and Chief Executive Officer
Jeffrey L. Ventura	51	2003	Director, President and Chief Operating Officer
Roger S. Manny	51	2003	Executive Vice President and Chief Financial Officer
Alan W. Farquharson	51	2007	Senior Vice President Reservoir Engineering
Steven L. Grose	60	2005	Senior Vice President Appalachia
David P. Poole	46	2008	Senior Vice President General Counsel and Corporate Secretary
Chad L. Stephens	53	1990	Senior Vice President Corporate Development
Rodney L. Waller	59	1999	Senior Vice President, Chief Compliance Officer and Assistant Corporate Secretary
Mark D. Whitley	57	2005	Senior Vice President Southwest Business Unit and Engineering Technology

Charles L. Blackburn was elected as a director in 2003. Mr. Blackburn has more than 40 years experience in oil and gas exploration and production serving in several executive and board positions. Previously, he served as Chairman and Chief Executive Officer of Maxus Energy Corporation from 1987 until that company s sale to YPF Socieded Anonima in 1995. Maxus was the oil and gas producer which remained after Diamond Shamrock Corporation s spin-off of its refining and marketing operations. Mr. Blackburn joined Diamond Shamrock in 1986 as President of their exploration and production subsidiary. From 1952 through 1986, Mr. Blackburn was with Shell Oil Company, serving as Director and Executive Vice President for exploration and production for the final ten years of that period. Mr. Blackburn has previously served on the Boards of Anderson Clayton and Co. (1978-1986), King Ranch Corp. (1987-1988), Penrod Drilling Co. (1988-1991), Landmark Graphics Corp. (1992-1996) and Lone Star Technologies, Inc. (1991-2001). Currently, Mr. Blackburn also serves as an advisory director to the oil and gas loan committee of Guaranty Bank. Mr. Blackburn received his Bachelor of Science degree in Engineering Physics from the University of Oklahoma.

Anthony V. Dub became a director in 1995. Mr. Dub is Chairman of Indigo Capital, LLC, a financial advisory firm based in New York. Before forming Indigo Capital in 1997, he served as an officer of Credit Suisse First Boston (CSFB). Mr. Dub joined CSFB in 1971 and was named a Managing Director in 1981. Mr. Dub led a number of departments during his 26 year career at CSFB including the Investment Banking Department. After leaving CSFB, Mr. Dub became Vice Chairman and a director of Capital IQ, Inc. until its sale to Standard & Poor s in 2004. Capital IQ is a leader in helping organizations capitalize on synergistic integration of market intelligence, institutional knowledge and relationships. Mr. Dub received a Bachelor of Arts, *magna cum laude*, from Princeton University.

V. Richard Eales became a director in 2001 and was selected as Lead Independent Director in 2008. Mr. Eales has over 35 years of experience in the energy, high technology and financial industries. He is currently retired, having been a financial consultant serving energy and information technology businesses from 1999 through 2002. Mr. Eales was employed by Union Pacific Resources Group Inc. from 1991 to 1999 serving as Executive Vice President from 1995 through 1999. Before 1991, Mr. Eales served in various financial capacities with Butcher & Singer and Janney Montgomery Scott, investment banking firms, as CFO of Novell, Inc., a technology company, and in the treasury department of Mobil Oil Corporation. Mr. Eales received his Bachelor of Chemical Engineering from Cornell University and his Master s degree in Business Administration from Stanford University.

James M. Funk became a director in December 2008. Mr. Funk is an independent consultant and producer with over 30 years of experience in the energy industry. Mr. Funk served as Sr. Vice President of Equitable Resources and President of Equitable Production Co. from June 2000 until January 2003. Previously, Mr. Funk worked for 23 years at Shell Oil Company in senior management and technical positions. Mr. Funk has previously served on the boards of Westport Resources (April 2000 to June 2004) and Matador Resources Company (January 2003 to December 2008). Mr. Funk currently serves as a Director of Superior Energy Services, Inc. a public oil field services company headquartered in New Orleans, Louisiana. Mr. Funk received an A.B. degree in Geology from Wittenberg University, a M.S. in Geology from the University of Connecticut, and a PhD in Geology from the University of Kansas. Mr. Funk is a Certified Petroleum Geologist.

Allen Finkelson became a director in 1994. Mr. Finkelson has been a partner at Cravath, Swaine & Moore LLP since 1977, with the exception of the period 1983 through 1985, when he was a managing director of Lehman Brothers Kuhn Loeb Incorporated. Mr. Finkelson joined Cravath, Swaine & Moore, LLP in 1971. Mr. Finkelson earned a Bachelor of Arts from St. Lawrence University and a J.D. from Columbia University School of Law.

Jonathan S. Linker became a director in 2002. Mr. Linker previously served as a director of Range from 1998 to 2000. He has been active in the energy industry since 1972. Mr. Linker joined First Reserve Corporation in 1988 and was a Managing Director of the firm from 1996 through 2001. Mr. Linker is currently Manager of Houston Energy Advisors LLC, an investment advisor providing management and investment services to two private equity funds. Mr. Linker has been President and a director of IDC Energy Corporation since 1987, a director and officer of Sunset Production Corporation since 1991 serving currently as Chairman, and Manager of Shelby Resources Inc., all small, privately-owned exploration and production companies. Mr. Linker received a Bachelor of Arts in Geology from Amherst College, a Masters in Geology from Harvard University and an MBA from Harvard Graduate School of Business Administration.

Kevin S. McCarthy became a director in 2005. Mr. McCarthy is Chairman, Chief Executive Officer and President of Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc. and Kayne Anderson Energy Development Company, which are each NYSE listed closed-end investment companies. Mr. McCarthy joined Kayne Anderson Capital Advisors as a Senior Managing Director in 2004 from UBS Securities LLC where he was global head of energy investment banking. In this role, he had senior responsibility for all of UBS energy investment banking activities, including direct responsibilities for securities underwriting and mergers and acquisitions in the energy industry. From 1995 to 2000, Mr. McCarthy led the energy investment banking activities of Dean Witter Reynolds and then PaineWebber Incorporated. He began his investment banking career in 1984. He is also on the board of directors of Clearwater Natural Resources, L.P., Pro Petro Services, Inc. and Direct Fuel Partners, L.P, three private energy companies. He earned a Bachelor of Arts in Economics and Geology from Amherst College and an MBA in Finance from the University of Pennsylvania s Wharton School.

John H. Pinkerton, Chairman, Chief Executive Officer and a director, became a director in 1988 and was elected Chairman of the Board of Directors in 2008. He joined Range as President in 1990 and was appointed Chief Executive Officer in 1992. Previously, Mr. Pinkerton was Senior Vice President of Snyder Oil Corporation (Snyder). Before joining Snyder in 1980, Mr. Pinkerton was with Arthur Andersen. Mr. Pinkerton received his Bachelor of Arts in Business Administration from Texas Christian University and a Master s degree from the University of Texas at Arlington.

Jeffrey L. Ventura, President and Chief Operating Officer, joined Range in 2003 and became a director in 2005. Previously, Mr. Ventura served as President and Chief Operating Officer of Matador Petroleum Corporation which he joined in 1997. Before 1997, Mr. Ventura spent eight years at Maxus Energy Corporation where he managed various engineering, exploration and development operations and was responsible for coordination of engineering technology. Previously, Mr. Ventura was with Tenneco Inc., where he held various engineering and operating positions. Mr. Ventura holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering from the Pennsylvania State University.

Roger S. Manny, Executive Vice President and Chief Financial Officer. Mr. Manny joined Range in 2003. Previously, Mr. Manny served as Executive Vice President and Chief Financial Officer of Matador Petroleum Corporation from 1998 until joining Range. Before 1998, Mr. Manny spent 18 years at Bank of America and its predecessors where he served as Senior Vice President in the energy group. Mr. Manny holds a Bachelor of Business Administration degree from the University of Houston and a Masters of Business Administration from Houston Baptist University.

Alan W. Farquharson, Senior Vice President Reservoir Engineering, joined Range in 1998. Mr. Farquharson has held the positions of Manager and Vice President of Reservoir Engineering before being promoted to his senior position in February 2007. Previously, Mr. Farquharson held positions with Union Pacific Resources including Engineering Manager Business Development International. Before that, Mr. Farquharson held various technical and managerial positions at Amoco and Hunt Oil. He holds a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University.

Steven L. Grose, Senior Vice President Appalachia, joined Range in 1980. Previously, Mr. Grose was employed by Halliburton Services, Inc. from 1971 until 1978. Mr. Grose is a member of the Society of Petroleum Engineers and is a past president of The Ohio Oil and Gas Association. Mr. Grose holds a Bachelor of Science degree in Petroleum Engineering from Marietta College.

David P. Poole, Senior Vice President General Counsel and Corporate Secretary, joined Range in June 2008. Mr. Poole has approximately 20 years of experience serving in various legal capacities. From 2004 until March 2008 he was with TXU Corp., serving most recently as Executive Vice President Legal, and General Counsel. Prior to joining TXU, Mr. Poole spent 16 years with Hunton & Williams LLP and its predecessor, where he last served as the Managing Partner of the Dallas office. Mr. Poole graduated from Texas Tech University with a B.S. in Petroleum Engineering and a J.D. *magna cum laude* from Texas Tech University School of Law.

Chad L. Stephens, Senior Vice President Corporate Development, joined Range in 1990. Before 2002, Mr. Stephens held the position of Senior Vice President Southwest. Previously, Mr. Stephens was with Duer Wagner & Co., an independent oil and gas producer for approximately two years. Before that, Mr. Stephens was an independent oil operator in Midland, Texas for four years. From 1979 to 1984, Mr. Stephens was with Cities Service Company and HNG Oil Company. Mr. Stephens holds a Bachelor of Arts in Finance and Land Management from the University of Texas.

Rodney L. Waller, Senior Vice President, Chief Compliance Officer and Assistant Corporate Secretary, joined Range in 1999. Mr. Waller served as Corporate Secretary from 1999 until 2008 and now serves as Assistant Corporate Secretary. In 2005, Mr. Waller was designated by our Board of Directors as the Chief Compliance Officer. Previously, Mr. Waller was Senior Vice President of Snyder Oil Corporation, now part of Devon Energy Corporation. Before joining Snyder, Mr. Waller was with Arthur Andersen. Mr. Waller is a certified public accountant and petroleum land man. Mr. Waller served as a director of Range from 1988 to 1994. Mr. Waller received a Bachelor of Arts degree in Accounting from Harding University.

Mark D. Whitley, Senior Vice President Southwest Business Unit and Engineering Technology, joined Range in 2005. Previously, he served as Vice President Operations with Quicksilver Resources for two years. Before joining Quicksilver, he served as Production/Operation Manager for Devon Energy, following the Devon/Mitchell merger. From 1982 to 2002, Mr. Whitley held a variety of technical and managerial roles with Mitchell Energy. Notably, he led the team of engineers at Mitchell Energy who applied new stimulation techniques to unlock the shale gas potential in the Fort Worth Basin. Previous positions included serving as a production and reservoir engineer with Shell Oil. He holds a Bachelor s degree in Chemical Engineering from Worcester Polytechnic Institute and a Master s degree in Chemical Engineering from the University of Kentucky.

Section 16(a) Beneficial Ownership Reporting Compliance

See the material appearing under the heading Section 16(a) Beneficial Ownership Reporting Compliance in the Range Proxy Statement for the 2009 Annual Meeting of stockholders which is incorporated herein by reference. Section 16(a) of the Exchange Act requires our directors, officers (including a person performing a principal policy-making function) and persons who own more than 10% of a registered class of our equity securities to file with the Commission initial reports of ownership and reports of changes in ownership of our common stock and other equity securities. Directors, officers and 10% holders are required by Commission regulations to send us copies of all of the Section 16(a) reports they file. Based solely on a review of the copies of the forms sent to us and the representations made by the reporting persons to us, we believe that, other than as described below, during the fiscal year ended December 31, 2008, our directors, officers and 10% holders complied with all filing requirements under Section 16(a) of the Exchange Act. Each of the following had one delinquent Form-4 filing on February 15, 2008 for a transaction that occurred on February 12, 2008: Mr. Alan Farquharson, Mr. Roger Manny, Mr. John Pinkerton, Mr.

Chad Stephens, Mr. Jeffrey Ventura, Mr. Rodney Waller and Mr. Mark Whitley.

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In addition, Mr. Chad Stephens had an additional delinquent Form-4 filing on May 14, 2008 for a transaction that occurred on May 9, 2008. Mr. David Poole had a delinquent Form-4 filing on February 12, 2009 for a transaction that occurred on September 12, 2008.

Code of Ethics

Code of Ethics. We have adopted a Code of Ethics that applies to our principal executive officers, principal financial officer, principal accounting officer, or persons performing similar functions (as well as directors and all other employees). A copy is available on our website, www.rangeresources.com and a copy in print will be provided to any person without charge, upon request. Such requests should be directed to the Corporate Secretary, 100 Throckmorton Street, Suite 1200, Fort Worth, Texas 76102 or by calling (817) 870-2601. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Controller and persons performing similar functions on our website, under the Corporate Governance caption, promptly following the date of such amendment or waiver.

Identifying and Evaluating Nominees for Directors

See the material under the heading Consideration of Director Nominees in the Range Proxy Statement for the 2009 Annual Meeting of stockholders, which is incorporated herein by reference.

Audit Committee

See the material under the heading Audit Committee in the Range Proxy Statement for the 2009 Annual Meeting of stockholders, which is incorporated herein by reference.

NYSE 303A Certification

The Chief Executive Officer of Range Resources Corporation made an unqualified certification to the NYSE with respect to the Company s compliance with the NYSE Corporate Governance listing standards on May 28, 2008.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2009 Annual Meeting of stockholders.

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

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2009 Annual Meeting of stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2009 Annual Meeting of stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated by reference to such information as set forth in the Range Proxy Statement for the 2009 Annual Meeting of stockholders.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of the report

1. **Financial Statements:**

2. All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

3. **Exhibits:**

(a) See Index of Exhibits on page 55 for a description of the exhibits filed as a part of this report.

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GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this glossary are used in this report.

bbl. One stock tank barrel, or 42 U.S. gallons liquid volumes, used herein in reference to crude oil or other liquid hydrocarbons.

bcf. One billion cubic feet of gas.

bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGL, which reflects relative energy content.

development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

dry hole. A well found to be incapable of producing oil or natural gas in sufficient economic quantities.

exploratory well. A well drilled to find oil or gas in an unproved area, to find a new reservoir in an existing field or to extend a known reservoir.

gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

infill well. A well drilled between known producing wells to better exploit the reservoir.

LIBOR. London Interbank Offer Rate, the rate of interest at which banks offer to lend to one another in the wholesale money markets in the City of London. This rate is a yardstick for lenders involved in many debt transactions.

Mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

mcf. One thousand cubic feet of gas.

mcf per day. One thousand cubic feet of gas per day.

mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGL, which reflects relative energy content.

Mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

Mmbtu. One million British thermal units. A British thermal unit is the heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

Mmcf. One million cubic feet of gas.

Mmcfe. One million cubic feet of gas equivalents.

NGLs. Natural gas liquids.

net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

present value (PV). The present value of future net cash flows, using a 10% discount rate, from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions). The after tax present value is the Standardized Measure.

productive well. A well that is producing oil or gas or that is capable of production.

proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

proved developed reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economics and operating conditions.
proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
recompletion. The completion for production an existing well bore in another formation from that in which the well has been previously completed.
reserve life index. Proved reserves at a point in time divided by the then production rate (annual or quarterly).
royalty acreage. Acreage represented by a fee mineral or royalty interest which entitles the owner to receive free and clear of all production costs a specified portion of the oil and gas produced or a specified portion of the value of such production.
royalty interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.
Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.
working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens, and to all costs of exploration, development and operations, and all risks in connection therewith.

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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.

Dated: February 24, 2009

RANGE RESOURCES CORPORATION

By: /s/ John H. Pinkerton
John H. Pinkerton
Chairman of the Board and Chief Executive Officer

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

/s/ John H. Pinkerton	Chairman of the Board and Chief Executive Officer	February 24, 2009
John H. Pinkerton		
/s/ Jeffrey L. Ventura	Director, President and Chief Operating Officer	February 24, 2009
Jeffrey L. Ventura		
/s/ Roger S. Manny	Chief Financial and Accounting Officer	February 24, 2009
Roger S. Manny		
/s/ Charles L. Blackburn	Director	February 24, 2009
Charles L. Blackburn		
/s/ Anthony V. Dub	Director	February 24, 2009
Anthony V. Dub		
/s/ V. Richard Eales	Lead Independent Director	February 24, 2009
V. Richard Eales		
/s/ Allen Finkelson	Director	February 24, 2009
Allen Finkelson		
/s/ James M. Funk	Director	February 24, 2009
James M. Funk		
/s/ Jonathan S. Linker	Director	February 24, 2009

Jonathan S. Linker		
/s/ Kevin S. McCarthy	Director	February 24, 2009
Kevin S. McCarthy		

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RANGE RESOURCES CORPORATION
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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders of
Range Resources Corporation:

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to management and the board of directors regarding the preparation and fair presentation of published 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. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2008. 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, we believe that, as of December 31, 2008, our internal control over financial reporting is effective based on those criteria.

Ernst and Young, LLP, the independent registered public accounting firm that audited our financial statements included in this annual report, has issued an attestation report on our internal control over financial reporting as of December 31, 2008. This report appears on the following page.

By: /s/ John H. Pinkerton	By: /s/ Roger S. Manny
John H. Pinkerton *Chairman of the Board and Chief Executive Officer*	Roger S. Manny *Executive Vice President and Chief Financial Officer*

Fort Worth, Texas
February 24, 2009

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Stockholders of
Range Resources Corporation:

We have audited Range Resources Corporation s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Range Resources Corporation s management is responsible 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 an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) 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.

In our opinion, Range Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Range Resources Corporation as of December 31, 2008 and 2007 and the related consolidated statements of operations, stockholders equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2008 and our report dated February 23, 2009 expressed an unqualified opinion thereon.

Ernst & Young LLP
Fort Worth, Texas
February 23, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Range Resources Corporation:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the Company) as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2008. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our 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 audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Range Resources Corporation at December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, in 2008, the Company adopted Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Range Resources Corporation s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2009 expressed an unqualified opinion thereon.

Ernst & Young LLP
Fort Worth, Texas
February 23, 2009

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RANGE RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except per share data)

	December 31, 2008	December 31, 2007
Assets		
Current assets:		
Cash and equivalents	$ 753	$ 4,018
Accounts receivable, less allowance for doubtful accounts of $954 and $583	162,201	166,484
Unrealized derivative gain	221,430	53,018
Deferred tax asset		26,907
Inventory and other	19,927	11,387
Total current assets	$ 404,311	$ 261,814
Unrealized derivative gain	5,231	1,082
Equity method investments	147,126	113,722
Oil and gas properties, successful efforts method	6,039,644	4,443,577
Accumulated depletion and depreciation	(1,186,934)	(939,769)
	4,852,710	3,503,808
Transportation and field assets	142,662	104,802
Accumulated depreciation and amortization	(56,434)	(43,676)
	86,228	61,126
Other assets	66,937	74,956
Total assets	$ 5,562,543	$ 4,016,508
Liabilities		
Current liabilities:		
Accounts payable	$ 250,640	$ 212,514
Asset retirement obligations	2,055	1,903
Accrued liabilities	47,309	42,964
Deferred tax liability	32,984	
Accrued interest	20,516	17,595
Unrealized derivative loss	10	30,457
Total current liabilities	353,514	305,433
Bank debt	693,000	303,500
Subordinated notes and other long term debt	1,097,668	847,158
Deferred tax liability	783,391	590,786
Unrealized derivative loss		45,819
Deferred compensation liability	93,247	120,223

Asset retirement obligations and other liabilities	83,890	75,567
Commitments and contingencies		
Stockholders Equity		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding		
Common stock, $0.01 par, 475,000,000 shares authorized, 155,609,387 issued at December 31, 2008 and 149,667,497 issued at December 31, 2007	1,556	1,497
Common stock held in treasury, 233,900 shares at December 31, 2008 and 155,500 shares at December 31, 2007	(8,557)	(5,334)
Additional paid-in capital	1,695,268	1,386,884
Retained earnings	692,059	371,800
Accumulated other comprehensive income (loss)	77,507	(26,825)
Total stockholders equity	2,457,833	1,728,022
Total liabilities and stockholders equity	$ 5,562,543	$ 4,016,508

See accompanying notes.

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31,		
	2008	**2007**	**2006**
Revenues			
Oil and gas sales	$ 1,226,560	$ 862,537	$ 599,139
Transportation and gathering	4,577	2,290	2,422
Derivative fair value income (loss)	70,135	(7,767)	142,395
Other	21,675	5,031	856
Total revenue	1,322,947	862,091	744,812
Costs and expenses			
Direct operating	142,387	107,499	81,261
Production and ad valorem taxes	55,172	42,443	36,415
Exploration	67,690	43,345	44,088
Abandonment and impairment of unproved properties	47,906	6,750	257
General and administrative	92,308	69,670	49,886
Deferred compensation plan	(24,689)	28,332	6,873
Interest expense	99,748	77,737	55,849
Depletion, depreciation and amortization	299,831	220,578	154,482
Total costs and expenses	780,353	596,354	429,111
Income from continuing operations before income taxes	542,594	265,737	315,701
Income tax provision			
Current	4,268	320	1,912
Deferred	192,168	98,441	119,840
	196,436	98,761	121,752
Income from continuing operations	346,158	166,976	193,949
Discontinued operations, net of taxes		63,593	(35,247)
Net income	$ 346,158	$ 230,569	$ 158,702
Earnings per common share:			
Basic-income from continuing operations	$ 2.29	$ 1.16	$ 1.45
-discontinued operations		0.44	(0.26)

-net income	$	2.29	$	1.60	$	1.19
Diluted-income from continuing operations	$	2.22	$	1.11	$	1.39
-discontinued operations				0.43		(0.25)
-net income	$	2.22	$	1.54	$	1.14
Weighted average common shares outstanding:						
Basic		151,116		143,791		133,751
Diluted		155,943		149,911		138,711

See accompanying notes.

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2008	2007	2006
Operating activities:			
Net income	$ 346,158	$ 230,569	$ 158,702
Adjustments to reconcile net cash provided from operating activities:			
(Income) loss from discontinued operations		(63,593)	35,247
Loss (income) from equity method investments	218	(974)	(548)
Deferred income tax expense	192,168	98,441	119,840
Depletion, depreciation and amortization	299,831	220,578	154,482
Exploration dry hole costs	13,371	15,149	15,089
Mark-to-market on oil and gas derivatives not designated as hedges	(83,868)	78,769	(86,491)
Abandonment and impairment of unproved properties	47,906	6,750	257
Unrealized derivative (gains) loss	(1,695)	820	(5,654)
Allowance for bad debts	450		80
Amortization of deferred financing costs and other	2,900	2,277	1,827
Deferred and stock-based compensation	6,621	54,152	27,455
(Gain) losses on sale of assets and other	(19,507)	2,212	940
Changes in working capital, net of amounts from business acquisitions:			
Accounts receivable	6,701	(50,570)	30,185
Inventory and other	(9,246)	(1,040)	(1,157)
Accounts payable	10,663	28,640	(5,049)
Accrued liabilities and other	12,096	9,922	(3,696)
Net cash provided from continuing operations	824,767	632,102	441,509
Net cash provided from discontinued operations		10,189	38,366
Net cash provided from operating activities	824,767	642,291	479,875
Investing activities:			
Additions to oil and gas properties	(881,950)	(782,398)	(487,245)
Additions to field service assets	(36,076)	(26,044)	(14,449)
Acquisitions, net of cash acquired	(834,758)	(336,453)	(360,149)
Investing activities of discontinued operations		(7,375)	(29,195)
Investment in equity method investment and other assets	(44,162)	(94,630)	(21,009)
Proceeds from disposal of assets and discontinued operations	68,231	234,332	388
Purchase of marketable securities held by the deferred compensation plan	(11,208)	(48,018)	
Proceeds from the sales of marketable securities held by the deferred compensation plan	8,146	40,014	
Net cash used in investing activities	(1,731,777)	(1,020,572)	(911,659)

Financing activities:			
Borrowing on credit facilities	1,476,000	864,500	802,500
Repayment on credit facilities	(1,086,500)	(1,013,000)	(619,700)
Issuance of subordinated notes	250,000	250,000	249,500
Dividends paid	(24,625)	(19,082)	(12,189)
Debt issuance costs	(8,710)	(3,686)	(6,960)
Issuance of common stock	291,183	296,229	16,265
Other debt repayment/financing	4,420	3,877	
Proceeds from the sales of common stock held by the deferred compensation plan	5,303	6,505	
Purchases of common stock held by the deferred compensation plan and other treasury stock purchases	(3,326)	(5,426)	
Net cash provided from financing activities	903,745	379,917	429,416
(Decrease) increase in cash and equivalents	(3,265)	1,636	(2,368)
Cash and equivalents at beginning of year	4,018	2,382	4,750
Cash and equivalents at end of year	$ 753	$ 4,018	$ 2,382

See accompanying notes.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In thousands)

	Common stock Shares	Common stock Par value	Treasury common stock	Additional paid-in capital	Retained earnings (deficit)	Deferred compensation	Accumulated other comprehensive (loss) income	Total
Balance December 31, 2005	**129,913**	**$ 1,299**	**$ (81)**	**$ 833,667**	**$ 13,800**	**$ (4,635)**	**$ (147,127)**	**$ 696,923**
Issuance of common stock	9,018	90		203,280		4,635		**208,005**
Stock-based compensation expense				20,991				**20,991**
Common dividends declared ($0.09 per share)					(12,189)			**(12,189)**
Treasury stock issuance			81					**81**
Other comprehensive income							183,648	**183,648**
Net income					158,702			**158,702**
Balance December 31, 2006	138,931	1,389		1,057,938	160,313		36,521	**1,256,161**
Issuance of common stock	10,736	108		312,427				**312,535**
Stock-based compensation expense				16,519				**16,519**
Common dividends declared ($0.13 per share)					(19,082)			**(19,082)**
Treasury stock purchase			(5,334)					**(5,334)**
Other comprehensive loss							(63,346)	**(63,346)**
Net income					230,569			**230,569**
	149,667	1,497	(5,334)	1,386,884	371,800		(26,825)	**1,728,022**

Balance December 31, 2007								
Issuance of common stock	5,942	59		291,822				**291,881**
Stock-based compensation expense				16,562				**16,562**
Common dividends declared ($0.16 per share)					(24,625)			**(24,625)**
Treasury stock purchase			(3,223)					**(3,223)**
Other comprehensive income							103,058	**103,058**
Net income					346,158			**346,158**
Adoption of SFAS No. 159, net of tax					(1,274)		1,274	
Balance December 31, 2008	**155,609**	**$ 1,556**	**$ (8,557)**	**$ 1,695,268**	**$ 692,059**	**$**	**$ 77,507**	**$ 2,457,833**

See accompanying notes.

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RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In thousands)

	December 31,		
	2008	**2007**	**2006**
Net income	$ 346,158	$ 230,569	$ 158,702
Other comprehensive (loss) income:			
Realized loss (gain) on hedge derivative contract settlements reclassified into earnings from other comprehensive (loss) income	38,557	(3,231)	60,764
Change in unrealized deferred hedging gains (losses)	64,501	(54,954)	120,832
Change in unrealized (losses) gains on securities held by deferred compensation plan, net of taxes		(5,161)	2,052
Total comprehensive income	$ 449,216	$ 167,223	$ 342,350

See accompanying notes.

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RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation (Range, we, us, or our) is engaged in the exploration, development and acquisitio of oil and gas properties primarily in the Southwestern, Appalachian and Gulf Coast regions of the United States. We seek to increase our reserves and production primarily through drilling and complementary acquisitions. Range is a Delaware corporation with its common stock trading on the New York Stock Exchange.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of all of our subsidiaries. Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting and are carried at our share of net assets plus loans and advances. Income from equity method investments represents our proportionate share of income generated by equity method investees and is included in Other revenues on our consolidated statement of operations. All material intercompany balances and transactions have been eliminated.

During the first quarter of 2007, we sold our interests in our Austin Chalk properties that we purchased as part of the Stroud acquisition (see also Note 3). We also sold our Gulf of Mexico properties at the end of the first quarter of 2007. In accordance with Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment of Disposal of Long-Lived Assets, we have reflected the results of operations of the above divestitures as discontinued operations, rather than a component of continuing operations. All periods presented reflect our Gulf of Mexico operations as discontinued operations. See also Note 4 for additional information regarding discontinued operations.

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end, the reported amounts of revenues and expenses during the year and the reported amount of proved oil and gas reserves. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments that are not readily apparent from other sources. Actual results could differ from the estimates and assumptions used.

Income per Common Share

Basic net income per share is calculated based on the weighted average number of common shares outstanding. Diluted net income per share assumes issuance of stock compensation awards, provided the effect is not antidilutive.

Business Segment Information

SFAS No. 131, Disclosure about Segments of an Enterprise and Related Information, establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which it may earn revenues and incur expenses for which separate operational financial information is available and this information is regularly evaluated by the chief decision maker for the purpose of allocating resources and assessing performance.

Segment reporting is not applicable to us as we have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, we allocate capital resources on a project-by-project basis, across our entire asset base to maximize profitability without regard to individual areas or segments.

Revenue Recognition and Gas Imbalances

Oil, gas and natural gas liquids revenues are recognized when the products are sold and delivery to the purchaser has occurred. We recognize the cost of revenues, such a transportation and compression expense, as a reduction to revenue. Although receivables are concentrated in the oil and gas industry, we do not view this as unusual credit risk. We provide for an allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We have allowances for doubtful accounts relating to exploration and production receivables of $954,000 at December 31, 2008 compared to $583,000 at December 31, 2007.

We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of the gas produced. A liability is recognized when the imbalance exceeds the estimate of remaining reserves. Gas imbalances at December 31, 2008 and December 31, 2007 were not significant. At December 31, 2008, we had recorded a net liability of $480,000 for those wells where it was determined that there were insufficient reserves to recover the imbalance situation.

Cash and Equivalents

Cash and cash equivalents include cash on hand and on deposit and investments in highly liquid debt instruments with maturities of three months or less.

Marketable Securities

Holdings of equity securities held in our deferred compensation plans qualify as trading and are recorded at fair value. Investments in the deferred compensation plans are in mutual funds.

Inventories

Inventories consist primarily of tubular goods used in our operations and are stated at the lower of specific cost of each inventory item or market value.

Oil and Gas Properties

We follow the successful efforts method of accounting for oil and gas producing activities. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed not less than quarterly. We capitalize successful exploratory wells and all developmental wells, whether successful or not. Oil and NGLs are converted to gas equivalent basis or mcfe at the rate of one barrel of oil equating to 6 mcf of gas. Depreciation, depletion and amortization of proved producing properties is provided on the units of production method based on estimated proved oil and gas reserves.

Our long-lived assets are reviewed for impairment periodically as events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Long-lived assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop proved reserves. Expected future net cash inflow from the sale of production of reserves is calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows) and the carrying value of the asset. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and gas prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs and future inflation. We cannot predict whether impairment charges may be required in the future.

Proceeds from the disposal of miscellaneous properties are credited to the net book value of their amortization group with no immediate effect on income. However, gain or loss is recognized from the sale of less than an entire amortization group if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

We adhere to the SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs related to unproved properties. The majority of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider a combination of time, geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $766.2 million in 2008 compared to $271.4 million in 2007 and $226.2 million in 2006. The increase from 2007 represents additional acreage purchases primarily in the Marcellus and Barnett Shale. We have recorded abandonment and impairment expense related to unproved properties of $47.9 million in 2008 compared to $6.8 million in 2007 and $257,000 in 2006.

Transportation and Field Assets

Our gas transportation and gathering systems are generally located in proximity to certain of our principal fields. Depreciation on these systems is provided on the straight-line method based on estimated useful lives of 10 to 15 years. We receive third-party income for providing field service and certain transportation services, which are recognized as earned. Depreciation on the associated assets is calculated on the straight-line method based on estimated useful lives ranging from five to seven years. Buildings are depreciated over 10 to 15 years. Depreciation expense was $13.7 million in 2008 compared to $10.9 million in 2007 and $7.5 million in 2006.

Other Assets

The expenses of issuing debt are capitalized and included in other assets on our consolidated balance sheet. These costs are amortized over the expected life of the related instruments. When a security is retired before maturity or modifications significantly change the cash flows, related unamortized costs are expensed. Other assets at December 31, 2008 include $21.7 million of unamortized debt issuance costs, $33.5 million of marketable securities held in our deferred compensation plans and $11.7 million of other investments.

Stock-based Compensation

The 2005 Equity Based Compensation Plan (the 2005 Plan) authorizes the Compensation Committee of the Board of Directors to grant, among other things, stock options, stock appreciation rights and restricted stock awards to employees. The 2004 Non-Employee Director Stock Plan (the Director Plan) allows grants to our non-employee directors of our Board of Directors. The 2005 Plan was approved by stockholders in May 2005 and replaced our 1999 stock option plan. No new grants will be made from the 1999 stock option plan. The number of shares that may be issued under the 2005 Plan is equal to (i) 5.6 million shares (15.0 million less the 2.2 million shares issued under the 1999 Stock Options Plan before May 18, 2005, the effective date of the 2005 Plan and less the 7.2 million shares issuable pursuant to awards under the 1999 Stock Option Plan outstanding as of the effective date of the 2005 Plan) plus (ii) the number of shares subject to 1999 Stock Option Plan awards outstanding at May 18, 2005, that subsequently lapse or terminate without the underlying shares being issued. The Director Plan was approved by stockholders in May 2004 and no more than 450,000 shares of common stock may be issued under the Plan.

Stock options represent the right to purchase shares of stock in the future at the fair market value of the stock on the date of grant. Most stock options granted under our stock option plans vest over a three year period and expire five years from the date they are granted. Beginning in 2005, we began granting stock-settled stock appreciation rights (SARs) to reduce the dilutive impact of our equity plans. Similar to stock options, SARs represent the right to receive a payment equal to the excess of the fair market value of shares of common stock on the date the right is exercised over the value of the stock on the date of grant. All SARs granted under the 2005 Plan will be settled in shares of stock, vest over a three-year period and have a maximum term of five years from the date they are granted.

The Compensation Committee grants restricted stock to certain employees and to non-employee directors of the Board of Directors as part of their compensation. Compensation expense is recognized over the balance of the vesting period, which is typically three years for employee grants and immediate vesting for non-employee directors. All restricted shares that are granted are placed in the deferred compensation plan. All vested restricted stock held in our deferred compensation plan is marked-to-market each reporting period based on the market value of our stock. This mark-to-market is presented in the caption Deferred compensation plan in our statement of operations. See additional information in Note 12.

The fair value of stock options and stock-settled SARs is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The model employs various assumptions, based on management s best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of grant.

Stock-based compensation represents amortization of restricted stock grants and stock option/SARs expense recognized under SFAS No. 123(R). In 2006, stock-based compensation was allocated to direct operating expense ($1.4 million), exploration expense ($2.5 million) and general and administrative expense ($10.7 million) to align SFAS No. 123(R) expense with the employees cash compensation. In 2007, stock-based compensation was allocated to direct operating expense ($1.8 million), exploration expense ($2.3 million) and general and administrative expense ($10.8 million). In 2008, stock-based compensation was allocated to direct operating expense ($2.8 million), exploration expense ($4.1 million) and general and administrative expense ($23.8 million) for a total of $31.2 million. We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant. Unlike the other forms of stock-based compensation mentioned above, the deferred compensation plan cost is directly tied to the change in our stock price and not directly related to the functional expenses and therefore, is not allocated to the functional categories.

Derivative Financial Instruments and Hedging

We account for our derivative activities under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. The statement, as amended, establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value. The statement requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. All of the derivative instruments that we use are to manage the price risk attributable to our expected oil and gas production. Cash flows from oil and gas derivative contract settlements are reflected in operating activities in our statement of cash flows.

Historically, we applied hedge accounting to qualifying derivatives used to manage price risk associated with our oil and gas production. Accordingly, we recorded changes in the fair value of our swap and collar contracts, including changes associated with time value, under the caption Accumulated other comprehensive income (loss) on our consolidated balance sheet. Gains or losses on these swap and collar contracts are reclassified out of Accumulated other comprehensive income (loss) and into Oil and gas sales when the forecasted sale of production occurred. Any hedge ineffectiveness associated with contracts qualifying for and designated as a cash flow hedge (which represents the amount by which the change in the fair value of the derivative differs from the change in the cash flows of the forecasted sale of production) is reported currently each period under the caption Derivative fair value income (loss) in our consolidated statement of operations.

To designate a derivative as a cash flow hedge, we document at the hedge s inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative s term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as oil or gas revenue when the underlying transaction occurs. If it is determined that the designated hedge transaction is not probable to occur, any unrealized gains or losses are recognized immediately in the statement of operations as a Derivative fair value income or loss. During 2008 and 2007, there were losses of $2.3 million and $14.5 million reclassified into earnings as a result of the discontinuance of hedge accounting treatment for our derivatives.

Some of our derivatives do not qualify for hedge accounting but are, to a degree, an economic offset to our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in our consolidated statement of operations under the caption Derivative fair value income (loss).

We also enter into basis swap agreements which do not qualify as hedges for hedge accounting and are also marked to market. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreement that effectively fix our basis adjustments.

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Asset Retirement Obligations

The fair values of asset retirement obligations are recognized in the period they are incurred, if a reasonable estimate of fair value can be made. Asset retirement obligations primarily relate to the abandonment of oil and gas producing facilities and include costs to dismantle and relocate or dispose of production platforms, gathering systems, wells and related structures. Estimates are based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. The depreciation will generally be determined on a units-of-production basis while accretion to be recognized will escalate over the life of the producing assets. We do not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined.

Deferred Taxes

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of assets and liabilities and their tax bases as reported in our filings with the respective taxing authorities. The realization of deferred tax assets is assessed periodically based on several interrelated factors. These factors include our expectation to generate sufficient taxable income including tax credits and operating loss carryforwards.

Accumulated Other Comprehensive Income (Loss)

We follow the provisions of SFAS No. 130, Reporting Comprehensive Income which establishes standards for reporting comprehensive income. Comprehensive income includes net income as well as all changes in equity during the period, except those resulting from investments and distributions to owners. At December 31, 2008, we had a $122.3 million pre-tax gain in accumulated other comprehensive income, or OCI, relating to unrealized commodity hedges. At December 31, 2007, we had a $41.1 million pre-tax loss in OCI relating to unrealized commodity hedges.

The components of accumulated other comprehensive income (loss) and related tax effects for three years ended December 31, 2008, were as follows (in thousands):

	Gross	Tax Effect	Net of Tax
Accumulated other comprehensive loss at December 31, 2005	$ (234,363)	$ 87,236	$ (147,127)
Contract settlements reclassified to income	96,450	(35,686)	60,764
Change in unrealized deferred hedging gains	192,183	(71,351)	120,832
Change in unrealized gains (losses) on securities held by deferred compensation plan	3,203	(1,151)	2,052
Accumulated other comprehensive income at December 31, 2006	57,473	(20,952)	36,521
Contract settlements reclassified to income	(5,129)	1,898	(3,231)
Change in unrealized deferred hedging gains	(87,228)	32,274	(54,954)
Change in unrealized gains (losses) on securities held by deferred compensation plan	(8,194)	3,033	(5,161)
Accumulated other comprehensive loss at December 31, 2007	(43,078)	16,253	(26,825)
Contract settlements reclassified to income	62,188	(23,631)	38,557
Change in unrealized deferred hedging gains	101,120	(36,619)	64,501
Adoption of SFAS No. 159	2,022	(748)	1,274
Accumulated other comprehensive income at December 31, 2008	$ 122,252	$ (44,745)	$ 77,507

Reclassifications

Certain reclassifications of prior years data have been made to conform to our current year classification. This includes the reclassification of abandonment and impairment expense for unproved properties from the line on statement of operations called Depletion, depreciation and amortization . These reclassifications did not impact our net income, stockholders equity or cash flows.

Accounting Pronouncements Implemented

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurement. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but provides guidance on how to measure fair value by providing a fair value hierarchy used to classify the source of the information. We adopted SFAS No. 157 effective January 1, 2008 for our financial instruments and the adoption did not have a significant effect on our consolidated results of operations, financial position or cash flows. See Note 11 for other disclosures required by SFAS No. 157. In February 2008, the FASB issued FSP SFAS No. 157-2 which delays the effective date of SFAS No. 157 for all non-financial assets and non-financial liabilities except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This deferral of SFAS No. 157 primarily impacts our asset retirement obligation (ARO), which uses fair value measures at the date incurred to determine our liability. We do not expect the pending adoption in 2009 of SFAS No. 157 non-recurring fair value measures to have a significant impact on our financial statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. This statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. It requires that unrealized gains and losses on items for which the fair value option has been elected be recorded in net income or loss. The statement also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. We adopted SFAS No. 159 effective January 1, 2008 and the impact of the adoption resulted in a reclassification of a $2.0 million pre-tax loss ($1.3 million after tax) related to our investment securities held in our deferred compensation plan from accumulated other comprehensive loss to retained earnings. We elected to adopt the fair value option to simplify our accounting for the investments in our deferred compensation plan. All investment securities held in our deferred compensation plans are reported in the balance sheet category called Other assets and total $33.5 million at December 31, 2008 compared to $51.5 million at December 31, 2007. As of January 1, 2008, all of these investment securities are accounted for using the mark-to-market accounting method, are classified as trading securities and all subsequent changes to fair value will be included in our statement of operations. For these securities, interest and dividends and mark-to-market gains or losses are included in our statement of operations category called Deferred compensation plan expense. For 2008, interest and dividends were $1.5 million and the mark-to-market was a loss of $19.4 million. See Note 11 for other disclosures required by SFAS No. 159.

Accounting Pronouncements Not Yet Adopted

In June 2008, the FASB issued Staff Position No. EITF 03-6-1 Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities, (FSP EITF 03-6-1) which provides that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. FSP EITF 03-6-1 is effective for us on January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) will be adjusted retroactively to conform to its provisions. Early application of FSP EITF 03-6-1 is not permitted. Although restricted stock awards meet this definition, we do not expect the application of FSP 03-6-1 to have a significant impact on our reported earnings per share.

In March 2008, the FASB issued SFAS No. 161, Disclosure about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why any entity uses derivative instruments; (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations; and (iii) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. SFAS No. 161 is effective for us on January 1, 2009 and will only impact future disclosures about our derivative instruments and hedging activities.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) replaces SFAS No. 141. The statement retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in the purchase method of accounting. It changes the recognition of assets acquired and liabilities assumed arising from contingencies, requires the capitalization of in-process research and development at fair value, and requires the expensing of acquisition-related costs as incurred. The statement will apply prospectively to business combinations occurring in our fiscal year beginning January 1, 2009. The effect of adopting SFAS No. 141(R) is not expected to have an effect on our reported financial position or earnings.

(3) ACQUISITIONS AND DISPOSITIONS

Acquisitions

Acquisitions are accounted for as purchases, and accordingly, the results of operations are included in our statement of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets and assumed liabilities based on their estimated fair value at the time of the acquisition. In the past, acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities.

In 2008, we completed several acquisitions of Barnett Shale producing and unproved properties for $331.2 million. After recording asset retirement obligations and transactions costs of $827,000, the purchase price allocated to proved properties was $232.9 million and unproved properties was $99.4 million. Also during 2008, we purchased unproved leaseholds for $494.3 million, which includes a single transaction to acquire Marcellus Shale unproved properties for $223.9 million.

In May 2007, we acquired additional interests in the Nora field of Virginia and entered into a joint development plan with Equitable Resources, Inc. (Equitable). As a result of this transaction, Equitable and Range equalized their working interests in the Nora field, including producing wells, undrilled acreage and gathering systems. Range retained its separately owned royalty interest in the Nora field. Equitable will operate the producing wells and manage the drilling operations of all future coal bed methane wells and the gathering system. Range will oversee the drilling of formations below the coal bed methane formations, including tight gas, shale and deeper formations. A newly formed limited liability corporation will hold the investment in the gathering system which is owned 50% by Equitable and 50% by Range. All business decisions require the unanimous consent of both parties. The gathering system investment is accounted for as an equity method investment. Including estimated transaction costs, we paid $281.8 million which includes $190.2 million allocated to oil and gas properties, $94.7 million allocated to our equity method investment and a $3.1 million asset retirement obligation. In December 2007, we paid an additional $7.1 million for additional interests in the same field. No pro forma information has been provided as the acquisition was not considered significant.

Our purchases in 2006 included the acquisition in June of Stroud Energy, Inc. (Stroud), a private oil and gas company with operations in the Barnett Shale in North Texas, the Cotton Valley in East Texas and the Austin Chalk in Central Texas. To acquire Stroud, we paid $171.5 million of cash (including transaction costs) and issued 6.5 million shares of our common stock. The cash portion of the acquisition was funded with borrowings under our bank facility. We also assumed $106.7 million of Stroud s debt which was retired with borrowings under our bank facility. The fair value of consideration issued was based on the average of our stock price for the five day period before and after May 11, 2006, the date the acquisition was announced. See also Note 4 for discussion of discontinued operations.

The following table summarizes the final purchase price allocation of fair value of assets acquired and liabilities assumed at closing (in thousands):

Purchase price:	
Cash paid (including transaction costs)	$ 171,529
6.5 million shares of common stock (at fair value of $27.26 per share)	177,641
Stock options assumed (652,000 options)	9,478
Debt retired	106,700
Total	$ 465,348
Allocation of purchase price:	
Working capital deficit	$ (13,557)
Other long-term assets	55
Oil and gas properties	487,345
Assets held for sale	140,000
Deferred income taxes	(147,062)

Asset retirement obligations	(1,433)
Total	$ 465,348

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Pro forma

The following unaudited pro forma data include the results of operations as if the Stroud acquisition had been consummated at the beginning of 2006. The pro forma data is based on historical information and does not necessarily reflect the actual results that would have occurred nor are they necessarily indicative of future results of operations (in thousands, except per share data).

	Year Ended December 31, 2006
Revenues	$ 779,487
Income from continuing operations	$ 315,220
Net income	$ 161,998
Per share data:	
Income from continuing operations-basic	$ 1.41
Income from continuing operations-diluted	$ 1.36
Net income basic	$ 1.18
Net income diluted	$ 1.14

Dispositions

In the first quarter of 2008, we sold East Texas properties for proceeds of $64.0 million and recorded a gain of $20.2 million. In February 2007, we sold the Stroud Austin Chalk properties for proceeds of $80.4 million and recorded a loss on the sale of $2.3 million. These properties were acquired in 2006 as part of our Stroud acquisition and were classified as assets held for sale on the acquisition date. In March 2007, we sold our Gulf of Mexico properties for proceeds of $155.0 million and recorded a gain on the sale of $95.1 million. We have reflected the results of operations of the Austin Chalk and Gulf of Mexico divestitures as discontinued operations rather than a component of continuing operations for 2007 and all prior years. See Note 4 for additional information.

(4) DISCONTINUED OPERATIONS

As part of the Stroud acquisition (see also discussion in Note 3), we purchased Austin Chalk properties in Central Texas, which were sold in February 2007 for proceeds of $80.4 million. We originally allocated $140.0 million to these properties as part of the purchase price allocation. However, after the acquisition, natural gas prices started to decline. As a result, during 2006 we recognized impairment expense of $74.9 million. In March 2007, we also sold our Gulf of Mexico properties for proceeds of $155.0 million. All prior year periods reflect our Gulf of Mexico operations and the Austin Chalk properties as discontinued operations. Discontinued operations for the years ended December 31, 2007 and 2006 are summarized as follows (in thousands):

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	2007	2006
Revenues		
Oil and gas sales [(a)]	$ 15,187	$ 54,192
Transportation and gathering	10	85
Other	310	(19)
Gain on disposition of assets	92,757	
Total revenues	108,264	54,258
Costs and expenses		
Direct operating	2,559	12,201
Production and ad valorem taxes	141	1,065
Exploration and other	215	2,400
Interest expense [(b)]	845	3,232
Depletion, depreciation and amortization	6,672	14,953
Impairment [(c)]		74,910
Total costs and expenses	10,432	108,761
Income (loss) from discontinued operations before income taxes	97,832	(54,503)
Income tax expense (benefit)	34,239	(19,256)
Income (loss) from discontinued operations, net of taxes	$ 63,593	$ (35,247)
Production		
Crude oil (bbls)	40,634	139,189
Natural gas (mcf)	1,990,277	7,927,557
Total (mcfe) [(d)]	2,234,081	8,762,691

a) Realized hedging gains and losses for the Gulf of Mexico properties have been allocated to discontinued operations based on the designated hedge values for those assets.

b) Interest expense is allocated to

discontinued operations for our Austin Chalk properties based on the debt incurred at the time of the acquisition and for the Gulf of Mexico properties, interest expense was allocated based upon the ratio of the Gulf of Mexico properties to our total oil and gas properties at December 31, 2006.

c) Impairment expenses for the Austin Chalk properties includes losses in fair value resulting from lower oil and gas prices and amortization of the carrying value for volumes produced since the acquisition date.

d) Oil is converted to mcfe at the rate of one barrel equals six mcf.

(5) INCOME TAXES

Our income tax expense from continuing operations was $196.4 million for the year ended December 31, 2008 compared to $98.8 million in 2007 and $121.8 million in 2006. A reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2008	2007	2006

Federal statutory tax rate	35.0%	35.0%	35.0%
State	2.1	2.8	3.6
Valuation allowance	0.2		
Other	(1.1)	(0.6)	
Consolidated effective tax rate	36.2%	37.2%	38.6%
Income taxes paid (refunded) (in thousands)	$ 4,298	$ (572)	$ 1,973

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Income tax provision (benefit) attributable to income from continuing operations consists of the following:

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Current:			
U.S. federal	$ 1,000	$ (129)	$ 150
U.S. state and local	3,268	449	1,762
	$ 4,268	$ 320	$ 1,912
Deferred:			
U.S. federal	$ 187,532	$ 94,310	$ 110,296
U.S. state and local	4,636	4,131	9,544
	$ 192,168	$ 98,441	$ 119,840
Total tax provision	$ 196,436	$ 98,761	$ 121,752

Significant components of deferred tax assets and liabilities are as follows:

	December 31,	
	2008	2007
	(in thousands)	
Deferred tax assets:		
Current		
Current net unrealized loss in OCI	$	$ 5,195
Deferred compensation	1,289	3,981
Current portion of asset retirement obligation	767	704
Other	4,411	2,967
Current portion of net operating loss carryforward	4,258	14,060
Subtotal	10,725	26,907
Non-current		
Net operating loss carryforward	21,033	34,476
Net unrealized loss in OCI		11,060
Deferred compensation	41,114	41,255
AMT credits and other credits	7,106	4,546
Non-current portion of asset retirement obligation	30,168	27,302
Other	12,602	9,046
Valuation allowance	(4,147)	(3,101)
Subtotal	107,876	124,584

Deferred tax liabilities:		
Current		
Net unrealized gain in OCI	(43,709)	
Subtotal	(43,709)	
Non-current		
Depreciation, depletion and investments	(851,803)	(707,111)
Net unrealized gain in OCI	(1,036)	
Cumulative unrealized mark-to-market gain	(38,055)	(6,812)
Other	(373)	(1,447)
Subtotal	(891,267)	(715,370)
Net deferred tax liability	$ (816,375)	$ (563,879)

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At December 31, 2008, deferred tax liabilities exceeded deferred tax assets by $816.4 million, with $44.7 million of deferred tax liability related to net deferred hedging gains included in OCI. We have a capital loss carryforward of $8.3 million and a full valuation allowance recorded of $2.9 million. Also in 2008, a valuation allowance of $1.2 million was recorded against the deferred tax asset related to our deferred compensation plan for planned future distributions to top level executives to the extent that their estimated future compensation plus distribution amounts would exceed the $1.0 million deductible limit provided under I.R.C. Section 162(m).

At December 31, 2008, we had regular net operating loss (NOL) carryforwards of $158.7 million and alternative minimum tax (AMT) NOL carryforwards of $90.8 million that expire between 2012 and 2027. Our deferred tax asset related to regular NOL carryforwards at December 31, 2008 was $10.2 million, which is net of the SFAS No. 123(R) reduction for unrealized benefits. Regular NOLs generally offset taxable income and to such extent, no income tax payments are required. At December 31, 2008, we have AMT credit carryforwards of $1.8 million that are not subject to limitation or expiration.

We file consolidated tax returns in the United States federal jurisdiction and separate income tax returns in many state jurisdictions. We are subject to U.S. Federal income tax examinations for the years after 2002 and we are subject to various state tax examinations for years after 2001. Our continuing policy is to recognize interest related to income tax expense in interest expense and penalties in general and administrative expense. We do not have any accrued interest or penalties related to tax amounts as of December 31, 2008. Throughout 2008, our unrecognized tax benefits were not material.

(6) EARNINGS PER COMMON SHARE

The following table sets forth the computation of basic and diluted earnings per common share (in thousands, except per share amounts):

	Year Ended December 31,		
	2008	2007	2006
Numerator:			
Income from continuing operations	$ 346,158	$ 166,976	$ 193,949
Income (loss) from discontinued operations		63,593	(35,247)
Net income	$ 346,158	$ 230,569	$ 158,702
Denominator:			
Weighted average shares, basic	151,116	143,791	133,751
Effect of dilutive securities:			
Employee stock options, SARs and stock held in deferred compensation plan	4,876	6,178	4,961
Treasury shares	(49)	(58)	(1)
Weighted average common shares diluted	155,943	149,911	138,711
Basic income from continuing operations	$ 2.29	$ 1.16	$ 1.45
discontinued operations		0.44	(0.26)
net income	$ 2.29	$ $1.60	$ 1.19
Diluted income from continuing operations	$ 2.22	$ 1.11	$ 1.39
discontinued operations		0.43	(0.25)

net income	$ 2.22	$ 1.54	$ 1.14

For December 31, 2008, stock appreciation rights for 880,000 shares were outstanding but not included in the computations of diluted earnings per share, because the grant price of the SARs was greater than the average price of the common stock and would be anti-dilutive to the computations (345,000 shares for the year ended December 31, 2007 and 88,500 shares for the year ended December 31, 2006).

(7) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the year ended December 31, 2008, 2007 and 2006 (in thousands):

	2008	2007	2006
Balance at beginning of period	$ 15,053	$ 9,984	$ 25,340
Additions to capitalized exploratory well costs pending the determination of proved reserves	43,968	14,428	4,695
Divested wells		(1,325)	
Reclassifications to wells, facilities and equipment based on determination of proved reserves	(3,847)		(16,710)
Capitalized exploratory well costs charged to expense	(7,551)	(8,034)	(3,341)
Balance at end of period	47,623	15,053	9,984
Less exploratory well costs that have been capitalized for a period of one year or less	(41,681)	(12,067)	(4,792)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 5,942	$ 2,986	$ 5,192
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	3	2	3

As of December 31, 2008, the $5.9 million of capitalized exploratory well costs that have been capitalized for more than one year relates to wells waiting on pipelines. Of the $47.6 million of capitalized exploratory well costs at December 31, 2008, $41.7 million was incurred in 2008 and $5.9 million in 2007.

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at December 31, 2008 is shown parenthetically). No interest was capitalized during 2008, 2007, and 2006 (in thousands):

	December 31,	
	2008	2007
Bank debt (2.9%)	$ 693,000	$ 303,500
Senior subordinated notes:		
7.375% senior subordinated notes due 2013, net of $2.0 million and $2.4 million discount, respectively	197,968	197,602
6.375% senior subordinated notes due 2015	150,000	150,000
7.5% senior subordinated notes due 2016, net of $405,000 and $444,000 discount, respectively	249,595	249,556
7.5% senior subordinated notes due 2017	250,000	250,000
7.25% senior subordinated notes due 2018	250,000	
Other	105	

Total debt	$ 1,790,668	$ 1,150,658

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Bank Debt

In October 2006, we entered into an amended and restated revolving bank facility, which we refer to as our bank debt or our bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On December 31, 2008, the facility amount was $1.25 billion and the borrowing base was $1.5 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and for event-driven unscheduled redeterminations. Our current bank group is comprised of twenty-six commercial banks each holding between 2.3% and 5.0% of the total facility. Of those twenty-six banks, fourteen are domestic banks and twelve are foreign banks or wholly-owned subsidiaries of foreign banks. The facility amount may be increased to the borrowing base amount with twenty days notice, subject to payment of a mutually acceptable commitment fee to those banks agreeing to participate in the facility increase. In December 2008, we elected to utilize the expansion option under our bank credit facility and increased our credit facility commitment by $250.0 million, which made the current bank commitment $1.25 billion. As of December 31, 2008, the outstanding balance under the bank credit facility was $693.0 million and there was $557.0 million of borrowing capacity available under the facility amount. The loan matures on October 25, 2012. Borrowings under the bank facility can either be at the Alternate Base Rate (as defined) plus a spread ranging from 0.875% to 1.625% or LIBOR borrowings at the Adjusted LIBO Rate (as defined) plus a spread ranging from 1.75% to 2.5%. The applicable spread is dependent upon borrowings relative to the borrowing base. We may elect, from time to time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 4.4% for the year ended December 31, 2008 compared to 6.4% for the year ended December 31, 2007. A commitment fee is paid on the undrawn balance based on an annual rate of 0.375% to 0.50%. At December 31, 2008, the commitment fee was 0.375% and the interest rate margin was 1.75%.

Senior Subordinated Notes

In 2003, we issued $100.0 million aggregate principal amount of 7.375% senior subordinated notes due 2013 (7.375% Notes). In 2004, we issued an additional $100.0 million of 7.375% Notes; therefore, $200.0 million of the 7.375% Notes is currently outstanding. The 7.375% Notes were issued at a discount which will be amortized over the life of the 7.375% Notes into interest expense. In 2005, we issued $150.0 million aggregate principal amount of 6.375% senior subordinated notes due 2015 (6.375% Notes). In May 2006, we issued $150.0 million aggregate principal amount of the 7.5% senior subordinated notes due 2016 (the 7.5% Notes due 2016). In August 2006, we issued an additional $100.0 million of the 7.5% Notes due 2016; therefore, $250.0 million of the 7.5% Notes due 2016 is currently outstanding. The 7.5% Notes due 2016 were also issued at a discount, which is being amortized over the life of the 7.5% Notes due 2016. In September 2007, we issued $250.0 million principal amount of 7.5% senior subordinated notes due 2017 (7.5% Notes due 2017). In May 2008, we issued $250.0 million aggregate principal amount of 7.25% senior subordinated notes due 2018 (7.25% Notes). Interest on our senior subordinated notes is payable semi-annually, at varying times, and each of the notes is guaranteed by certain of our subsidiaries.

We may redeem the 7.375% Notes, in whole or in part, at any time on or after July 15, 2008, at redemption prices of 103.7% of the principal amount as of July 15, 2008, and declining to 100.0% on July 15, 2011 and thereafter. We may redeem the 6.375% Notes, in whole or in part, at any time on or after March 15, 2010, at redemption prices from 103.2% of the principal amount as of March 15, 2010 and declining to 100% on March 15, 2013 and thereafter. We may redeem the 7.5% Notes due 2016, in whole or in part, at any time on or after May 15, 2011 at redemption prices from 103.75% of the principal amount as of May 15, 2011 and declining to 100% on May 15, 2014 and thereafter. Before May 15, 2009, we may redeem up to 35% of the original aggregate principal amount of the 7.5% Notes due 2016 at a redemption price of 107.5% of principal amount thereof plus accrued and unpaid interest if any, with the proceeds of certain equity offerings; provided that at least 65% of the original aggregate principal amount of our 7.5% Notes 2016 remains outstanding immediately after the occurrence of such redemption and provided that such redemption occurs within 60 days of the date of closing the equity sale. We may redeem the 7.5% Notes due 2017, in whole or in part, at any time on or after October 1, 2012 at redemption prices ranging from 103.75% of the principal amount as of October 1, 2012 and declining to 100% on October 1, 2015 and thereafter. Before October 1, 2010, we may redeem up to 35% of the original aggregate principal amount of the 7.5% Notes due 2017 at a redemption price of 107.5% of principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings provided that at least 65% of the original aggregate principal amount of our 7.5% Notes due 2017 remains outstanding immediately after the occurrence of such redemption and provided that such redemption occurs 60 days of the date of closing the equity sale. We may redeem the 7.25% Notes, in whole or in part, at any time on or after May 1, 2016 at redemption prices of 103.625% of the principal amount as of May 1, 2013 and declining to 100.0% on May 1, 2016 and thereafter. Before May 1, 2011, we may redeem up to 35% of the original aggregate principal amount of the 7.25% Notes at a redemption price equal to 107.25% of the principal amount thereof, plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings provided that at least 65% of the original principal amount of the 7.25% Notes remain outstanding immediately after the occurrence of such redemption and also provided such redemption shall occur within 60 days of the date of the closing of the equity offering.

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If we experience a change of control, there will be a requirement to repurchase all or a portion of the senior subordinated notes at 101% of the principal amount plus accrued and unpaid interest, if any. All of the senior subordinated notes and the guarantees by our subsidiary guarantors are general, unsecured obligations and are subordinated to our bank debt and will be subordinated to future senior debt that we or our subsidiary guarantors are permitted to incur under the bank credit facility and the indentures governing the subordinated notes.

Guarantees

Range Resources Corporation is a holding company which owns no operating assets and has no significant operations independent of its subsidiaries. The guarantees by our subsidiaries of the 7.375% Notes, the 6.375% Notes, the 7.5% Notes due 2016, the 7.5% Notes due 2017 and the 7.25% Notes are full and unconditional and joint and several; any subsidiaries other than the subsidiary guarantors are minor subsidiaries.

Debt Covenants and Maturity

Our bank credit facility contains negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain hedging contracts, change the nature of our business or operations, merge, consolidate, or make investments. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined in the credit agreement) of no greater than 4.0 to 1.0 and a current ratio (as defined in the credit agreement) of no less than 1.0 to 1.0. We were in compliance with our covenants under the bank credit facility at December 31, 2008.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2008 (in thousands):

	Year Ended December 31,
2009	$
2010	
2011	
2012	693,022
2013	198,050
2014	
Thereafter	899,596
	$ 1,790,668

The indentures governing our senior subordinated notes contain various restrictive covenants that are substantially identical and may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, enter into transactions with affiliates, or change the nature of our business. At December 31, 2008, we were in compliance with these covenants.

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(9) ASSET RETIREMENT OBLIGATION

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives. A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2008 and 2007 is as follows (in thousands):

	2008	2007
Beginning of period	$ 75,308	$ 95,588
Liabilities incurred	2,347	3,118
Acquisitions continuing operations	250	3,301
Liabilities settled	(1,399)	(2,782)
Disposition of wells	(898)	(20,066)
Accretion expense continuing operations	5,471	5,960
Accretion expense discontinued operations		382
Change in estimate	2,378	(10,193)
End of period	83,457	75,308
Less current portion	(2,055)	(1,903)
Long-term asset retirement obligation	$ 81,402	$ 73,405

Accretion expense is recognized as a component of depreciation, depletion and amortization on our statement of operations.

(10) CAPITAL STOCK

In May 2008, at our annual meeting, our shareholders approved an increase to our number of authorized shares of common stock. We now have authorized capital stock of 485.0 million shares which includes 475.0 million shares of common stock and 10.0 million shares of preferred stock. The following is a schedule of changes in the number of common shares outstanding since the beginning of 2007:

	Year Ended December 31,	
	2008	2007
Beginning balance	149,511,997	138,931,565
Public offerings	4,435,300	8,050,000
Shares issued in lieu of bonuses		29,483
Stock options/SARs exercised	1,339,536	2,220,627
Restricted stock grants	167,054	408,067
Shares contributed to 401(k) plan		27,755
Treasury shares	(78,400)	(155,500)
Ending balance	155,375,487	149,511,997

In May 2008, we completed a public offering of 4.4 million shares of common stock at $66.38 per share. After underwriting discount and other offering costs of $12.3 million, net proceeds of $282.2 million were used to repay indebtedness on our bank credit facility. In April 2007, we completed a public offering of 8.1 million shares of common stock at $36.28 per share. Total proceeds from the offering of $280.4 million funded our acquisition of properties and a gathering system in Virginia.

Treasury Stock

In 2008, the Board of Directors approved up to $10.0 million of repurchases of common stock based on market conditions and opportunities. During 2008, we repurchased 78,400 shares of common stock an average price of $41.11 for a total of $3.2 million. As of December 31, 2008, we have $6.8 million remaining authorization to repurchase shares.

(11) FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

Financial instruments include cash and equivalents, receivables, payables, marketable securities, debt and commodity derivatives. The carrying value of cash and equivalents, receivables, payables is considered to be representative of fair value because of their short maturity.

The following table sets forth our other financial instruments fair values at each of these dates (in thousands):

	December 31, 2008		December 31, 2007	
	Book Value	Fair Value	Book Value	Fair Value
Derivative assets:				
Commodity swaps and collars [(a)]	$ 226,661	$ 226,661	$ 54,100	$ 54,100
Derivative liabilities:				
Commodity swaps and collars [(a)]	(10)	(10)	(76,276)	(76,276)
Net derivative asset (liability)	$ 226,651	$ 226,651	$ (22,176)	$ (22,176)
Marketable securities [(b)]	$ 33,473	$ 33,473	$ 51,482	$ 51,482
Long-term debt [(c)]	$ 1,790,668	$ 1,621,793	$ 1,150,658	$ 1,158,033

(a) All derivatives are marked to market and therefore their book value is equal to fair value.

(b) Marketable securities held in our deferred compensation plans which are marked to market and therefore their book value is equal to fair value.

(c) The book value of our bank debt approximates fair value because of its floating rate structure. The fair value of our senior subordinated notes is based on year-end market quotes.

Commodity Derivative Instruments

We use commodity-based derivative contracts to manage exposures to commodity price fluctuations. We do not enter into these arrangements for speculative or trading purposes. These contracts consist of collars and fixed price swaps. We do not utilize complex derivatives such as swaptions, knockouts or extendable swaps. At December 31, 2008, we had open swap contracts covering 25.6 Bcf of gas at prices averaging $8.38 per mcf. We also had collars covering 54.8 Bcf of gas at weighted average floor and cap prices of $8.28 to $9.27 per mcf and 2.9 million barrels of oil at weighted average floor and cap prices of $64.01 to $76.00 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a net unrealized pre-tax gain of $214.2 million at December 31, 2008. These contracts expire monthly through December 2009. The following table sets forth the derivative volumes by year as of December 31, 2008:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price	
Natural Gas				
2009	Swaps	70,000 Mmbtu/day	$8.38	
2009	Collars	150,000 Mmbtu/day	$8.28	$9.27
Crude Oil				
2009	Collars	8,000 bbl/day	$64.01	$76.00

Under SFAS No. 133, every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date. Changes in the fair value of effective cash flow hedges are recorded as a component of Accumulated other comprehensive income (loss), which is later transferred to earnings when the hedged transaction occurs. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized in earnings. As of December 31, 2008, an unrealized pre-tax derivative gain of $122.2 million was recorded in Accumulated other comprehensive income (loss). This gain will be reclassified into earnings in 2009 as the contracts settle. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date.

For those derivative instruments that qualify for hedge accounting, settled transaction gains and losses are determined monthly, and are included as increases or decreases to Oil and gas sales in the period the hedged production is sold. Oil and gas sales include $63.6 million of losses in 2008 compared to gains of $4.2 million in 2007 and losses of $93.2 million in 2006. Any ineffectiveness associated with these hedges is reflected in the caption called Derivative fair value income (loss) in our statement of operations. The year ended December 31, 2008 includes ineffective unrealized gains of $1.7 million compared to losses of $820,000 in 2007 and gains of $6.0 million in 2006.

Some of our derivatives do not qualify for hedge accounting but are, to a degree, an economic offset to our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. We recognize all unrealized and realized gains and losses related to these contracts in the income statement caption called Derivative fair value income (loss) (see table below).

In addition to the swaps and collars above, we have entered into basis swap agreements which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be more or less than the NYMEX price because of adjustments for delivery location, relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix our basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax gain of $12.4 million at December 31, 2008.

Derivative fair value income (loss)

The following table presents information about the components of derivative fair value income (loss) in the three-year period ended December 31, 2008 (in thousands):

	2008	2007	2006
Change in fair value of derivatives that do not qualify for hedge accounting	$ 83,867	$ (78,769)	$ 86,491
Realized (loss) gain on settlement-gas [(a)]	(1,383)	71,098	49,939
Realized loss on settlement-oil [(a)]	(15,431)	(244)	
Hedge ineffectiveness realized	1,386	968	
unrealized	1,696	(820)	5,965
Derivative fair value income (loss)	$ 70,135	$ (7,767)	$ 142,395

(a) These amounts represent the realized gains and losses on settled derivatives that do not qualify for hedge accounting, which before settlement are included in the category above called the change in fair value of derivatives that do not qualify for hedge accounting.

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The combined fair value of derivatives included in our consolidated balance sheets as of December 31, 2008 and December 31, 2007 is summarized below (in thousands). We conduct derivative activities with twelve financial institutions, ten of which are secured lenders in our bank credit facility. We believe all of these institutions are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of our counterparties is subject to periodic review. The assets and liabilities are netted where derivatives with both gain and loss positions are held by a single counterparty.

	December 31, 2008	December 31, 2007
Derivative assets:		
Natural gas swaps	$ 57,280	$ 54,577
collars	121,781	4,916
basis swaps	12,434	1,082
Crude oil collars	35,166	(6,475)
	$ 226,661	$ 54,100
Derivative liabilities:		
Natural gas swaps	$	$ 6,594
collars		11,302
basis swap	(10)	(937)
Crude oil collars		(93,235)
	$ (10)	$ (76,276)

Fair Value Measurements

Effective January 1, 2008, we adopted SFAS No. 157, as discussed in Note 2, which among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 describes three approaches to measuring the fair value of assets and liabilities: the market approach, the income approach and the cost approach, each of which include multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset.

SFAS No. 157 does not prescribe which valuation technique should be used when measuring fair value and does not prioritize among techniques. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and lowest priority to unobservable inputs (level 3 measurements). The three levels of fair value hierarchy defined by SFAS No. 157 are as follows:

Level 1 Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities as of the reporting date.

Level 2 Pricing inputs are other than quoted prices in active markets included in either Level 1, which are directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data, which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

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Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. At December 31, 2008, we have no Level 3 measurements.

We use a market approach for our fair value measurements and endeavor to use the best information available. Accordingly, valuation techniques that maximize the use of observable impacts are favored. The following table presents the fair value hierarchy table for assets and liabilities measured at fair value, on a recurring basis, as set forth in SFAS No. 157 (in thousands):

		Fair Value Measurements at December 31, 2008 Using		
	Total Carrying Value as of December 31, 2008	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Trading securities held in the deferred compensation plans	$ 33,473	$ 33,473	$	$
Derivatives swaps	57,280		57,280	
collars	156,947		156,947	
basis swaps	12,424		12,424	

These items are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Our trading securities in Level 1 are exchange-traded and measured at fair value with a market approach using December 31, 2008 market values. Derivatives in Level 2 are measured at fair value with a market approach using third-party pricing services which have been corroborated with data from active markets or broker quotes.

Concentration of Credit Risk

Most of our receivables are from a diverse group of companies, including major energy companies, pipeline companies, local distribution companies, financial institutions and end-users in various industries. Letters of credit or other appropriate security are obtained as necessary to limit risk of loss. Our allowance for uncollectible receivables was $954,000 at December 31, 2008 and $583,000 at December 31, 2007. Commodity-based contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. These contracts consist of collars and fixed price swaps. This exposure is diversified among major investment grade financial institutions the majority of which we have master netting agreements with that provide for offsetting payables against receivables from separate derivative contracts. Our derivative counterparties include twelve financial institutions, ten of which are secured lenders in our bank credit facility. Mitsui & Co. and J. Aron & Company are the two counterparties not in our bank group. At December 31, 2008, our net derivative receivable includes a receivable from J. Aron & Company of $987,000 and a receivable from Mitsui & Co. for $18.0 million.

(12) EMPLOYEE BENEFIT AND EQUITY PLANS

Stock and Option Plans

We have six equity-based stock plans, of which two are active. Under the active plans, incentive and non-qualified stock options, stock appreciation rights and annual cash incentive awards may be issued to directors and employees pursuant to decisions of the Compensation Committee, which is made up of outside independent directors from the Board of Directors. All stock options and SARs granted under these plans have been issued at the prevailing market price at the time of the grant. Since the middle of 2005, only SARs have been granted under the plans to limit the dilutive impact of our equity plans. Information with respect to stock option and SARs activities is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2005	8,742,305	$ 9.31
Granted	1,658,160	24.36
Stock options assumed in Stroud acquisition	652,062	19.67
Exercised	(2,051,237)	9.22
Expired/forfeited	(149,164)	18.32
Outstanding at December 31, 2006	8,852,126	12.76
Granted	1,680,643	33.78
Exercised	(2,461,689)	9.45
Expired/forfeited	(298,755)	23.42
Outstanding at December 31, 2007	7,772,325	17.95
Granted	1,159,649	63.18
Exercised	(1,590,390)	12.24
Expired/forfeited	(92,918)	40.82
Outstanding at December 31, 2008	7,248,666	$ 26.15

The following table shows information with respect to outstanding stock options and SARs at December 31, 2008:

			Outstanding		Exercisable	
Range of Exercise Prices		Shares	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Shares	Weighted Average Exercise Price
$1.29	$9.99	1,495,340	2.01	$ 4.47	1,495,340	$ 4.47
10.00	19.99	1,878,048	1.33	16.25	1,878,048	16.25
20.00	29.99	1,295,286	2.25	24.37	750,081	24.34
30.00	39.99	1,455,132	3.26	33.98	410,482	34.61
40.00	49.99	29,130	4.17	42.37	5,010	42.67
50.00	59.99	720,565	4.12	58.57	180	58.60

60.00	69.99	28,427	4.37	65.33		
70.00	75.00	346,738	4.38	75.00	26,484	75.00
Total		7,248,666	2.47	$ 26.15	4,565,625	$ 15.74

During 2008, 2007 and 2006, we granted SARs to officers, non-officer employees and directors. The weighted average grant date fair value of these SARs, based on our Black-Scholes-Merton assumptions, is shown below:

	2008	2007	2006
Weighted average exercise price per share	$63.18	$33.78	$24.36
Expected annual dividends per share	0.26%	0.36%	0.30%
Expected life in years	3.5	3.5	3.5
Expected volatility	41%	36%	41%
Risk-free interest rate	2.4%	4.7%	4.8%
Weighted average grant date fair value	$20.58	$10.67	$ 8.51

The volatility factors are based on a combination of both the historical volatilities of the stock and implied volatility of traded options on our common stock. The dividend yield is based on the current annual dividend at the time of grant. For SARs granted in 2007 and 2006, we used the simplified method prescribed by SEC Staff Accounting Bulletin No. 107 to estimate the expected term of the options, which is calculated based on the midpoint between the vesting date and the life of the SAR. For SARs granted in 2008, the expected term was based on the historical exercise activity. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options. Of the 7.2 million grants outstanding at December 31, 2008, 2.5 million grants relate to stock options with the remainder of 4.7 million grants relating to SARs.

The total intrinsic value (the difference in value between exercise and market price) of stock options and SARs exercised during the years ended December 31, 2008 was $67.9 million compared to $67.2 million in 2007 and $37.1 million in 2006. As of December 31, 2008, the aggregate intrinsic value of the awards outstanding was $94.4 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option/SARs awards currently exercisable was $87.0 million and 1.9 years. As of December 31, 2008, the number of fully vested awards and awards expected to vest was 7.2 million. The weighted average exercise price and weighted average remaining contractual life of these awards were $25.81 and 2.45 years and the aggregate intrinsic value was $94.3 million. As of December 31, 2008, unrecognized compensation cost related to the awards was $23.2 million, which is expected to be recognized over a weighted average period of 0.9 years.

For the year ended December 31, 2008, total stock-based compensation expense for stock options and SARs under SFAS No. 123(R) was $16.6 million compared to $15.2 million in 2007. For 2008, the total related tax benefits were $4.1 million. For the year ended December 31, 2008, cash received upon exercise of stock option awards was $9.0 million. Due to the net operating loss carryforward for tax purposes, tax benefits realized for deductions that were in excess of the stock-based compensation expense were not recognized.

Restricted Stock Grants

In 2008, we issued 362,000 shares of restricted stock grants as compensation to directors and employees at an average price of $63.00. The restricted stock grants included 14,400 issued to directors, which vest immediately and 347,600 to employees with vesting generally over a three-year period. In 2007, we issued 435,000 shares of restricted stock grants as compensation to directors and employees, at an average price of $34.85. The restricted grants included 15,900 issued to directors, which vest immediately, and 419,100 to employees with vesting over a three-year period. In 2006, we issued 499,200 shares of restricted stock grants as compensation to directors and employees, at an average price of $24.43. The restricted grants included 15,000 issued to directors, which vest immediately, and 484,200 to employees with vesting over a three-to-four year period. We recorded compensation expense for restricted stock grants of $14.7 million in the year ended December 31, 2008 compared to $8.7 million in 2007 and $4.3 million in 2006. As of December 31, 2008, there was $23.1 million of unrecognized compensation related to restricted stock awards expected to be recognized over the next three years, prior to mark-to-market adjustments. The vesting of these shares is dependent only upon the employees continued service with us. For restricted stock grants, the fair value is equal to the closing price of our common stock on the grant date. All of our restricted stock grants are held in our deferred compensation plan and the liability is marked-to-market each reporting period based on the value of our stock. This mark-to-market is presented in the statement of operations caption Deferred compensation plan (see discussion below). The proceeds received from the sale of stock held in our deferred compensation plan was $5.3 million in 2008.

A summary of the status of our non-vested restricted stock outstanding at December 31, 2008 and changes during the twelve months then ended, is presented below:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2007	563,660	$ 30.42
Granted	362,313	63.00
Vested	(438,058)	37.54
Forfeited	(14,368)	38.87
Non-vested shares outstanding at December 31, 2008	473,547	$ 48.50

401(k) Plan

We maintain a 401(k) Plan for our employees. The 401(k) Plan permits employees to contribute up to 50% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. Historically, we have made discretionary contributions of our common stock to the 401(k) Plan annually. Beginning in 2008, we began matching up to 6% of salary in cash. All our contributions become fully vested after the individual employee has two years of service with us. In 2008, we contributed $2.7 million to the 401(k) Plan compared to $2.3 million in 2007 and $1.9 million in 2006. We do not require that employees hold any contributed Range stock in their account. Employees have a variety of investment options in the 401(k) Plan. Employees may, at any time, diversify out of our stock, based on their personal investment strategy.

Deferred Compensation Plan

In 1996, the Board of Directors adopted a deferred compensation plan (the Plan). The Plan gave directors, officers and key employees the ability to defer all or a portion of their salaries and bonuses and invest in Range common stock or make other investments at the individual s discretion. Great Lakes Energy Partners (which we purchased in 2004) also had a deferred compensation plan that allowed certain employees to defer all or a portion of their salaries and bonuses and invest such amounts in certain investments at the employee s discretion. In December 2004, we adopted the Range Resources Corporation Deferred Compensation Plan (2005 Deferred Compensation Plan). The 2005 Deferred Compensation Plan is intended to operate in a manner substantially similar to the old plans, subject to new requirements and changes mandated under Section 409A of the Internal Revenue Code. The old plans will not receive additional contributions. The assets of all of the plans are held in a rabbi trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is treated as a liability award (as defined by SFAS No. 123(R)) as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The liability for the vested portion of the stock held in the Rabbi Trust is reflected in the deferred compensation liability on our balance sheet and is adjusted to fair value each reporting period by a charge or credit to Deferred compensation plan expense on our consolidated statement of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at their market value in the balance sheet category Other assets . The deferred compensation liability on our consolidated balance sheet reflects the vested market value of the marketable securities and the Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities and changes in the fair value of the liability are charged or credited to Deferred compensation plan expense each quarter. We recorded mark-to-market income of $24.7 million in 2008 compared to mark-to-market expense of $28.3 million in 2007 and $6.9 million in 2006. The Rabbi Trust held 2.3 million shares (1.9 million of vested shares) of Range stock at December 31, 2008 compared to 2.1 million shares (1.5 million of vested shares) at December 31, 2007.

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(13) SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2008	2007	2006
		(in thousands)	
Net cash provided from continuing operations included:			
Income taxes paid to (refunded from) taxing authorities	$ 4,298	$ (572)	$ 1,973
Interest paid	93,954	71,708	55,925
Non-cash investing and finance activities:			
6.5 million shares issued for Stroud acquisition	$	$	$ 177,641
Stock options (652,000) issued in Stroud acquisition			9,478
Asset retirement costs capitalized, excluding acquisitions [a]	4,647	(7,075)	25,821

[a] For information regarding purchase price allocations of businesses acquired see Note 9.

(14) COMMITMENTS AND CONTINGENCIES

Litigation

We are involved in various legal actions and claims arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on our financial position, cash flows or results of operations.

Lease Commitments

We lease certain office space, compressors and equipment under cancelable and non-cancelable leases. Rent expense under such arrangements totaled $9.2 million in 2008 compared to $5.4 million in 2007 and $5.0 million in 2006. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. Future minimum rental commitments under non-cancelable leases having remaining lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations
2009	$ 10,423
2010	10,536
2011	8,943
2012	6,057
2013	3,528
Thereafter	9,257
Sublease rentals	(139)
	$ 48,605

Other Commitments

We also have agreements in place to purchase seismic data. These agreements total $900,000 in both 2009 and 2010. We have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally not exceeding two years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed acreage to expire and will allow additional acreage to expire in the future.

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Transportation Contracts

We have entered firm transportation contracts with various pipelines. Under these contracts, we are obligated to transport minimum daily gas volumes, or pay for any deficiencies at a specified reservation fee rate. In most cases, our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. As of December 31, 2008, future minimum transportation fees under our gas transportation commitments are as follows (in thousands):

	Transportation Commitments
2009	$ 17,369
2010	16,725
2011	16,270
2012	13,332
2013	12,529
Thereafter	69,145
	$ 145,370

In addition to the amounts included in the above table, we have contracted with a pipeline company through 2017 to deliver natural gas production volumes in Appalachia from certain Marcellus Shale wells. The agreement calls for incremental increases over the initial 40,000 Mmbtu per day. These increases, which are contingent on certain pipeline modifications, are 30,000 Mmbtu per day in March 2009, 30,000 Mmbtu per day in October 2009, 30,000 Mmbtu per day in March 2010 and an additional 20,000 Mmbtu per day for July 2010 for a total of an additional 110,000 Mmbtu per day.

Drilling Contracts

As of December 31, 2008, we have contracts with drilling contractors to use six drilling rigs with terms of up to three years and minimum future commitments of $26.9 million in 2009, $58.4 million in both 2010 and 2011 and $31.7 million in 2012. Early termination of these contracts at December 31, 2008 would have required us to pay maximum penalties of $129.3 million. We do not expect to pay any early termination penalties related to these contracts.

Delivery Commitments

Under a sales agreement with Enterprise Products Operating, LLC, we have an obligation to deliver 30,000 Mmbtu per day of volume at various delivery points within the Barnett Shale basin. The contract, which began in 2008, extends for five years ending March 2013. As of December 31, 2008, remaining volumes to be delivered under this commitment are approximately 46.5 bcf.

(15) MAJOR CUSTOMERS

We market our production on a competitive basis. Gas is sold under various types of contracts including month-to-month, and one-to-five-year contracts. Pricing on the month-to-month and short-term contracts is based largely on NYMEX, with fixed or floating basis. For one to five-year contracts, we sell our gas on NYMEX pricing, published regional index pricing or percentage of proceeds sales based on local indices. We sell our oil under contracts ranging in terms from month-to-month, up to as long as one year. The price for oil is generally equal to a posted price set by major purchasers in the area or is based on NYMEX pricing or fixed pricing, adjusted for quality and transportation differentials. We sell to oil and gas purchasers on the basis of price, credit quality and service reliability. For the year ended December 31, 2008, one customer accounted for 10% or more of total oil and gas revenues. For the year ended December 31, 2007, we had no customers that accounted for 10% or more of total oil and gas revenues. For the year ended December 31, 2006, two customers each accounted for 10% or more of total oil and gas revenues and the combined sales to those customers accounted for 25% of total oil and gas revenues. We believe that the loss of any one customer would not have a material adverse effect on our results.

(16) EQUITY METHOD INVESTMENTS

We account for our investments in entities over which we have significant influence, but not control, using the equity method of accounting. Under the equity method of accounting, we record our proportionate share of the net earnings, declared dividends and partnership distributions based on the most recently available financial statements of the investee. We also evaluate our equity method investments for potential impairment whenever events or changes in circumstances indicate that there is an other-than-temporary decline in value of the investment. Such events may include sustained operating losses by the investee or long-term negative changes in the investee s industry. These indicators were not present, and as a result, we did not

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recognize any impairment charges related to our equity method investments for the years ended December 31, 2008, 2007 or 2006.

Investment in Whipstock Natural Gas Services, LLC

In 2006, we acquired a 50% interest in Whipstock Natural Gas Services, LLC (Whipstock), an unconsolidated investee in the business of providing oil and gas drilling equipment, well servicing rigs and equipment, and other well services in Appalachia. On the acquisition date, we contributed cash of $11.7 million representing the fair value of 50% of the membership interest in Whipstock.

Whipstock follows a calendar year basis of financial reporting consistent with us and our equity in Whipstock s earnings from the acquisition date is included in other revenue in our results of operations for 2008, 2007 and 2006. During the year ended December 31, 2008, we received cash distributions from Whipstock of $1.8 million. There were no dividends or partnership distributions received from Whipstock during the years ended December 31, 2007 or 2006. In determining our proportionate share of the net earnings of Whipstock, certain adjustments are required to be made to Whipstock s reported results to eliminate the profits recognized by Whipstock for services provided to us. For the year ended December 31, 2008, our equity in the earnings of Whipstock totaled $479,000, compared to $132,000 in 2007 and $548,000 in 2006. In 2008, equity in the earnings of Whipstock was reduced by $1.8 million to eliminate the profit on services provided to us compared to $2.7 million in 2007 and $1.1 million in 2006. Range and Whipstock have entered into an agreement whereby Whipstock will provide us with the right of first refusal such that we will have the opportunity to secure services from Whipstock in preference to and in advance of Whipstock entering into additional commitments for services with other customers. All services provided to us are based on Whipstock s usual and customary terms.

Investment in Nora Gathering, LLC

In May 2007, we completed the initial closing of a joint development arrangement with Equitable Production Company. Pursuant to the terms of the arrangement, Range and Equitable (the parties) agreed to among other things, form a new pipeline and natural gas gathering operations entity, Nora Gathering, LLC (NGLLC). NGLLC is an unconsolidated investee created by the parties for the purpose of conducting pipeline, natural gas gathering, and transportation operations associated with the parties collective interests in properties in the Nora Field. In connection with the acquisition, we contributed cash of $94.7 million for a 50% membership interest in NGLLC. During 2008, Range and Equitable each contributed $29.0 million in additional capital to NGLLC in order to fund the expansion of the Nora Field gathering system infrastructure.

NGLLC follows a calendar year basis of financial reporting consistent with Range and our equity in NGLLC earnings from the acquisition date is included in other revenue in our results of operations for 2008 and 2007. There were no dividends or partnership distributions received from NGLLC during the years ended December 31, 2008 or December 31, 2007. In determining our proportionate share of the net earnings of NGLLC, certain adjustments are required to be made to NGLLC s reported results to eliminate the profits recognized by NGLLC included in the gathering and transportation fees charged to us on production in the Nora field. For the year ended December 31, 2008 our equity in the earnings of NGLLC of $261,000 was reduced by $4.8 million to eliminate the profit on gathering fees charged to us. For the year ended December 31, 2007, our equity in the earnings of NGLLC of $841,000 was reduced by $1.8 million to eliminate the profit on gathering and transportation fees charged to us. The gathering and transportation rate charged by NGLLC to us on our production in the Nora field is considered to be at market.

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(17) SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years (in thousands). As discussed in Note 2, certain reclassifications have been made to conform to our current year classifications. This includes the reclassification of abandonment and impairment expense for unproved properties from depletion, depreciation and amortization. These reclassifications did not impact net income.

	2008				
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 307,384	$ 347,622	$ 347,720	$ 223,834	$ 1,226,560
Transportation and gathering	1,129	1,224	1,537	687	4,577
Derivative fair value (loss) income	(123,767)	(198,410)	272,869	119,443	70,135
Other	20,592	(359)	544	898	21,675
Total revenues	205,338	150,077	622,670	344,862	1,322,947
Costs and expenses					
Direct operating	32,950	37,228	36,532	35,677	142,387
Production and ad valorem taxes	13,840	16,056	15,210	10,066	55,172
Exploration	16,593	19,462	19,149	12,486	67,690
Abandonment and impairment of unproved properties	1,437	5,348	4,483	36,638	47,906
General and administrative	17,412	23,938	24,650	26,308	92,308
Deferred compensation plan	20,611	7,539	(37,515)	(15,324)	(24,689)
Interest expense	23,146	23,842	25,373	27,387	99,748
Depletion, depreciation and amortization	70,133	72,115	76,690	80,893	299,831
Total costs and expenses	196,122	205,528	164,572	214,131	780,353
Income (loss) from continuing operations before income taxes	9,216	(55,451)	458,098	130,731	542,594
Income tax provision (benefit)					
Current	886	949	2,374	59	4,268
Deferred	6,590	(21,818)	170,400	36,996	192,168
	7,476	(20,869)	172,774	37,055	196,436
Net income (loss)	$ 1,740	$ (34,582)	$ 285,324	$ 93,676	$ 346,158
Earnings per common share:					
Basic	$ 0.01	$ (0.23)	$ 1.87	$ 0.61	$ 2.29

Diluted	$	0.01	$	(0.23)	$	1.81	$	0.60	$	2.22

			2007		
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 193,316	$ 213,896	$ 214,424	$ 240,901	$ 862,537
Transportation and gathering	184	511	508	1,087	2,290
Derivative fair value (loss) income	(42,620)	28,766	24,974	(18,887)	(7,767)
Other	1,961	341	2,447	282	5,031
Total revenues	152,841	243,514	242,353	223,383	862,091
Costs and expenses					
Direct operating	25,414	24,816	28,003	29,266	107,499
Production and ad valorem taxes	10,412	11,230	11,316	9,485	42,443
Exploration	11,710	11,725	6,233	13,677	43,345
Abandonment and impairment of unproved properties	156		1,707	4,887	6,750
General and administrative	14,678	17,838	18,058	19,096	69,670
Deferred compensation plan	11,247	9,334	7,761	(10)	28,332
Interest expense	18,848	17,573	19,935	21,381	77,737
Depletion, depreciation and amortization	47,176	51,465	55,294	66,643	220,578
Total costs and expenses	139,641	143,981	148,307	164,425	596,354
Income from continuing operations before income taxes	13,200	99,533	94,046	58,958	265,737
Income tax provision (benefit)					
Current	384	(101)	133	(96)	320
Deferred	4,447	34,449	34,802	24,743	98,441
	4,831	34,348	34,935	24,647	98,761
Income from continuing operations	8,369	65,185	59,111	34,311	166,976
Discontinued operations, net of taxes	64,768	(979)	(196)		63,593
Net income	$ 73,137	$ 64,206	$ 58,915	$ 34,311	$ 230,569
Earnings per common share:					
Basic income from continuing operations	$ 0.06	$ 0.45	$ 0.40	$ 0.23	$ 1.16
discontinued operations	0.47	(0.01)			0.44

net income	$	0.53	$	0.44	$	0.40	$	0.23	$	1.60
Diluted income from continuing operations	$	0.06	$	0.43	$	0.39	$	0.22	$	1.11
discontinued operations		0.45								0.43
net income	$	0.51	$	0.43	$	0.39	$	0.22	$	1.54

Principal Unconsolidated Investees (unaudited)

Company	December 31, 2008 Ownership	Activity
Whipstock Natural Gas Services, LLC	50%	Drilling services
Nora Gathering, LLC	50%	Gas gathering and transportation

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(18) SUPPLEMENTAL INFORMATION ON NATURAL GAS AND OIL EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES

The following information concerning our gas and oil operations has been provided pursuant to SFAS No. 69, Disclosures about Oil and Gas Producing Activities, . Our gas and oil producing activities are conducted onshore within the continental United States and offshore in the Gulf of Mexico. Our Gulf of Mexico assets were sold in first quarter 2007. In December 2008, the SEC announced revisions to modernize oil and gas reporting requirements which are effective for our December 31, 2009 reporting period. We are in the process of evaluating the impact of these new requirements.

Capitalized Costs and Accumulated Depreciation, Depletion and Amortization [a]

	December 31, 2008	2007	2006
	(in thousands)		
Oil and gas properties:			
Properties subject to depletion	$ 5,273,458	$ 4,172,151	$ 3,132,927
Unproved properties	766,186	271,426	226,166
Total	6,039,644	4,443,577	3,359,093
Accumulated depreciation, depletion and amortization	(1,186,934)	(939,769)	(751,005)
Net capitalized costs	$ 4,852,710	$ 3,503,808	$ 2,608,088

(a) Includes capitalized asset retirement costs and the associated accumulated amortization.

Costs Incurred for Property Acquisition, Exploration and Development [a]

	Year Ended December 31, 2008	2007	2006
	(in thousands)		
Acquisitions:			
Unproved leasehold	$ 99,446	$ 4,552	$ 132,821
Proved oil and gas properties	251,471	253,064	209,262
Purchase price adjustment [b]			147,062
Asset retirement obligations	251	3,301	896
Acreage purchases [c]	494,341	78,095	79,762
Development	729,268	734,987	464,586
Exploration:			
Drilling	133,116	40,567	25,618
Expense	63,560	39,872	42,173
Stock-based compensation expense	4,130	3,473	3,079
Gas gathering facilities:			
Exploratory			3,418
Development	47,056	18,655	16,272

Subtotal	1,822,639	1,176,566	1,124,949
Asset retirement obligations	4,647	(7,075)	25,821
Total costs incurred [(d)]	$ 1,827,286	$ 1,169,491	$ 1,150,770
Assets held for sale:			
Acquisitions	$	$	$ 140,110
Development	$	$ 1,114	$ 15,012

[(a)] Includes cost incurred whether capitalized or expensed.

[(b)] Represents the offset to our deferred tax liability resulting from differences in book and tax basis at date of acquisition.

[(c)] Includes a single transaction to acquire Marcellus Shale acreage for $223.9 million.

[(d)] 2006 includes $21.5 million related to our divested Gulf of Mexico properties.

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Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

Reserves of crude oil, condensate, natural gas liquids and natural gas are estimated by our engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

The SEC defines proved reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered as a result of additional investments for drilling new wells to offset productive units, recompleting existing wells, and/or installing facilities to collect and transport production.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, and, especially in the case of natural gas, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future net cash flows because prices, costs and governmental policies do not remain static, appropriate discount rates may vary, and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average realized prices used at December 31, 2008 to estimate reserve information were $42.76 per barrel of oil, $25.00 per barrel for natural gas liquids and $5.23 per mcf for gas, using benchmark prices (NYMEX) of $44.60 per barrel and $5.71 per Mmbtu. The average realized prices used at December 31, 2007 to estimate reserve information were $91.88 per barrel for oil, $52.64 per barrel for natural gas liquids and $6.44 per mcf for gas, using benchmark prices (NYMEX) of $95.98 per barrel and $6.80 per Mmbtu. The average realized prices used at December 31, 2006 to estimate reserve information were $57.66 per barrel for oil, $25.98 per barrel for natural gas liquids and $5.24 per mcf for gas, using benchmark prices (NYMEX) of $61.05 per barrel and $5.64 per Mmbtu. All of our proved reserves are located within the United States.

	Crude Oil and NGLs (Mbbls)	Natural Gas (Mmcf)	Natural Gas Equivalents [b] (Mmcfe)
Proved developed and undeveloped reserves:			
Balance, December 31, 2005	46,892	1,125,410	1,406,762
Revisions	(42)	(48,609)	(48,863)
Extensions, discoveries and additions	10,871	314,261	379,491
Purchases	242	121,683	123,133
Property sales	(4)	(1,500)	(1,522)
Production	(4,252)	(75,267)	(100,775)
Balance, December 31, 2006 [a]	53,707	1,435,978	1,758,226
Revisions	2,432	(386)	14,207
Extensions, discoveries and additions	13,741	401,805	484,250
Purchases	1,934	121,382	132,984
Property sales	(649)	(35,362)	(39,254)
Production	(4,505)	(90,620)	(117,651)
Balance, December 31, 2007	66,660	1,832,797	2,232,762
Revisions	(3,155)	(23,397)	(42,333)
Extensions, discoveries and additions	15,841	423,354	518,404
Purchases	53	95,262	95,578
Property sales	(1,592)	(147)	(9,701)
Production	(4,471)	(114,323)	(141,145)
Balance, December 31, 2008	73,336	2,213,546	2,653,565
Proved developed reserves:			
December 31, 2006	37,750	875,395	1,101,895
December 31, 2007	47,015	1,144,709	1,426,802
December 31, 2008	49,009	1,337,978	1,632,032

[a] The December 31, 2006 balance excludes reserves associated with the Austin Chalk

properties. The total proved developed and undeveloped reserves for these assets at December 31, 2006 were 42.3 Bcfe, which is comprised of 39.3 Bcfe of gas. These assets were sold in the first quarter of 2007.

(b) Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcf.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following summarizes the policies we used in the preparation of the accompanying gas and oil reserve disclosures, standardized measures of discounted future net cash flows from proved gas and oil reserves and the reconciliations of standardized measures from year to year. The information disclosed, as prescribed by SFAS No. 69, is an attempt to present the information in a manner comparable with industry peers.

The information is based on estimates of proved reserves attributable to our interest in gas and oil properties as of December 31 of the years presented. These estimates were prepared by our petroleum engineering staff. Proved reserves are estimated quantities of natural gas and crude oil, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

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The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and future amounts expected to be produced based on current year-end economic conditions.
2. Estimated future cash inflows are calculated by applying current year-end prices of gas and oil relating to our proved reserves to the quantities of those reserves produced in each future year.
3. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current year-end economic conditions. Future income tax expenses are based on current year-end statutory tax rates giving effect to the remaining tax basis in the gas and oil properties, other deductions, credits and allowances relating to our proved gas and oil reserves.
4. The resulting future net cash flows are discounted to present value by applying a discount rate of 10%.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of our gas and oil reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The standardized measure of discounted future net cash flows relating to proved gas and oil reserves is as follows and excludes cash flows associated with hedges outstanding at each of the respective reporting dates.

	As of December 31,	
	2008	2007
	(in thousands)	
Future cash inflows	$ 14,293,651	$ 17,231,826
Future costs:		
Production	(4,034,065)	(3,859,591)
Development	(1,818,509)	(1,464,229)
Future net cash flows before income taxes	8,441,077	11,908,006
Future income tax expense	(2,381,826)	(3,854,952)
Total future net cash flows before 10% discount	6,059,251	8,053,054
10% annual discount	(3,477,871)	(4,386,691)
Standardized measure of discounted future net cash flows	$ 2,581,380	$ 3,666,363

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The following table summarizes changes in the standardized measure of discounted future net cash flows.

	As of December 31,		
	2008	2007	2006
		(in thousands)	
Beginning of period	$ 3,666,363	$ 2,002,224	$ 3,384,310
Revisions of previous estimates:			
Changes in prices	(1,675,703)	1,310,378	(2,390,159)
Revisions in quantities	(65,931)	37,188	(91,793)
Changes in future development costs	(688,259)	(542,684)	(623,607)
Accretion of discount	520,482	277,144	488,737
Net change in income taxes	719,595	(769,242)	733,846
Purchases of reserves in place	148,857	348,119	231,314
Additions to proved reserves from extensions, discoveries and improved recovery	807,386	1,267,649	712,902
Production	(1,029,001)	(711,354)	(554,788)
Development costs incurred during the period	333,979	304,165	223,158
Sales of gas and oil	(15,109)	(102,757)	(2,859)
Timing and other	(141,279)	245,533	(108,837)
End of period	$ 2,581,380	$ 3,666,363	$ 2,002,224

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RANGE RESOURCES CORPORATION
INDEX TO EXHIBITS

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated May 10, 2006, by and among Range Resources Corporation, Range Acquisition Texas, Inc. and Stroud Energy, Inc. (incorporated by reference to Exhibit 2.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 16, 2006)
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004) as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on February 17, 2009)
4.1	Form of 7.375% Senior Subordinated Notes due 2013 (included as an exhibit to exhibit 4.2 hereto)
4.2	Indenture dated July 21, 2003 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors, and Bank One, National Association, as trustee (incorporated by reference to Exhibit 4.4.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
4.3	Form of 6.375% Senior Subordinated Notes due 2015 (included as an exhibit to exhibit 4.4 hereto)
4.4	Indenture dated March 9, 2005 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors and J.P.Morgan Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 15, 2005)
4.5	Form of 7.5% Senior Subordinated Notes due 2016 (included as an exhibit to exhibit 4.6 hereto)
4.6	Indenture dated May 23, 2006 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors and J.P.Morgan Trust Company, National Association as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on May 23, 2006)
4.7	Form of 7.5% Senior Subordinated Notes due 2017 (included as exhibit 4.8 hereto)
4.8	Indenture dated September 28, 2007 by and among Range, as issuer, the subsidiary Guarantors (as defined herein), as guarantors and J.P.Morgan Trust Company, National Association as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on October 1, 2007)
10.1	Third Amended and Restated Credit Agreement as of October 25, 2006 among Range (as borrowers) and J.P.Morgan Chase Bank, N.A. and the institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 10-K (File No. 001-12209) as filed with the SEC February 27, 2007)

10.2	First Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC April 26, 2007)
10.3	Second Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC April 26, 2007)
10.4	Third Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.4 to our Form 10-K (File No. 001-12209) as filed with the SEC February 27, 2008)
10.5	Fourth Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to Exhibit 10.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC April 24, 2008)
10.6*	Fifth Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent
10.7*	Sixth Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent
10.8	Amended and Restated Range Resources Corporation Deferred Compensation Plan for Directors and Select Employees effective December 2, 2008 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on December 5, 2008)

Exhibit No.	Description
10.9	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.5 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 18, 2005)
10.10	Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.7 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 18, 2005)
10.11	First Amendment to the Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.8 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 18, 2005)
10.12	Second Amendment to the Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 26, 2006)
10.13	Third Amendment to the Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.3 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 26, 2006)
10.14	Fourth Amendment to the Range Resources 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 4.5 to our Form S-8 (File No. 333-143875) as filed with the SEC on June 19, 2007)
10.15	Fifth Amendment to the Range Resources 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 4.6 to our Form S-8 (File No. 333-143875) as filed with the SEC on June 19, 2007)
10.16	Lomak 1989 Stock Option Plan dated March 13, 1989 (incorporated by reference to Exhibit 10.1(d) to Lomak s Form S-1 (File No. 33-31558) as filed with the SEC on October 13, 1989)
10.17	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.1 to Lomak s Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.18	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.2 to Lomak s Form S-8 (File No. 333-44821) as filed with the SEC on January 23, 1998)
10.19	Lomak 1994 Outside Directors Stock Option Plan (incorporated by reference to Exhibit 4.2 to Lomak s Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.20	First Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 8, 1995 (incorporated by reference to Exhibit 4.6 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.21	Second Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated August 21, 1996 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)

10.22	Third Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 1, 1999 (incorporated by reference to Exhibit 4.8 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.23	Fourth Amendment to the Lomak 1994 Outside Directors Stock Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.9 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.24	2004 Non-Employee Director Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)
10.25	Lomak 1997 Stock Purchase Plan, as amended, dated June 19, 1997 (incorporated by reference to Exhibit 10.1(1) to Lomak s Form 10-K (File No. 001-12209) as filed with the SEC on March 20, 1998)
10.26	First Amendment to the Lomak 1997 Stock Purchase Plan dated May 26, 1999 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.27	Second Amendment to the Lomak 1997 Stock Purchase Plan dated September 28, 1999 (incorporated by reference to Exhibit 4.3 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.28	Third Amendment to the Lomak 1997 Stock Purchase Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.4 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.29	Fourth Amendment to the Lomak 1997 Stock Purchase Plan dated May 24, 2001 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-63764) as filed with the SEC on June 25, 2001)
10.30	Amended and Restated 1999 Stock Option Plan (as amended May 21, 2003) (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-105895) as filed with the SEC on June 6, 2003)
10.31	Fourth Amendment to the Amended and Restated 1999 Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)
10.32	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to our Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.33	Amended and Restated Range Resources Corporation Executive Change in Control Severance Benefit Plan dated December 2, 2008 (incorporated by reference to exhibit 10.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on December 5, 2008)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Independent Registered Public Accounting Firm
23.2*	Consent of H.J. Gruy and Associates, Inc., independent consulting engineers
23.3*	Consent of DeGoyler and MacNaughton, independent consulting engineers
23.4*	Consent of Wright and Company, independent consulting engineers

31.1*	Certification by the President and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

Exhibit No.	Description
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the President and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed herewith.

** Furnished herewith.