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.

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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

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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

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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

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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.

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%

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.

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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
	Gross	Net	Interest
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.

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.

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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

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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.

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 f