RANGE RESOURCES CORP
Form 10-K
February 27, 2008

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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, 2007

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	Smaller reporting company o
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates (excluding voting shares held by officers and directors) as of June 29, 2007 was $5,459,435,000.

As of February 20, 2008, there were 149,903,625 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 2008 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, 2007

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 upon 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 early 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 286%, while production has increased 115% during that same period.

At year-end 2007, our proved reserves had the following characteristics:

2.2 Tcfe of proved reserves;

82% natural gas;

64% proved developed;

77% operated;

a reserve life of 17.7 years (based on fourth quarter 2007 production);

- a pre-tax present value of $5.2 billion of future net revenues attributable to our reserves, discounted at 10% per annum (PV-10); and
- a standardized measure of discounted future net cash flows of $3.7 billion (after tax).

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,

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because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future 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 $1.5 billion at December 31, 2007.

At year-end 2007, we owned 3,385,000 gross (2,695,000 net) acres of leasehold, including 407,800 acres where we also own a royalty interest. We have built a multi-year inventory drilling that is estimated to contain over 11,000 drilling locations, with approximately 8,500 drilling locations in our Appalachian region.

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 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 onshore 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.

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 11,000 identified drilling locations in inventory. In 2007, we drilled 967 gross (698 net) wells. In 2008, our capital program targets the drilling of 968 gross (715 net) wells.

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 $903.8 million of complementary acquisitions. These acquisitions have been located in the Southwestern and Appalachian regions.

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.

Equity Ownership and Incentive Compensation. We want our employees to act like owners. To achieve this, we reward and encourage them through equity ownership in us. As of December 31, 2007, our employees owned equity securities (vested and unvested) that had an aggregate market value of approximately $260 million.

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Significant Accomplishments in 2007

Production and reserve growth The fourth quarter of 2007 marked the 20th consecutive quarter of sequential production growth. In 2007, our annual production averaged 319.0 Mmcfe per day, an increase of 22% from 2006, after reclassification of 2006 to report the results of the Gulf of Mexico properties sold in the first quarter of 2007 as discontinued operations. See Note 4 to our consolidated financial statements. 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 five 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 27% in 2007 to 2.2 Tcfe, marking the sixth consecutive year our proven reserves have increased.

Successful drilling program In 2007, we drilled 967 gross wells. Production was replaced by 416% through drilling in 2007, 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.

Continued expansion of drilling inventory and emerging plays To continue to grow, the size of our prospect inventory must remain large. Our drilling inventory currently includes over 11,000 projects, up from 9,400 at year-end 2006. We engaged in meaningful expansion of our coal bed methane plays and our shale plays in 2007. We have now leased 286,000 net acres in our coal bed methane plays and 1.0 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 balance sheet enhancement Growth in production volumes and higher oil and gas prices drove our record financial performance in 2007. 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 7.5% notes having a 10-year maturity. This helped to align the maturity schedule of our debt with the long-term life of our assets. Financial leverage, as measured by the debt-to-capitalization ratio improved from 46% to 40%. Future cash flow will be enhanced through low income tax payments due to a $204.4 million net operating loss carryforward.

Successful acquisitions completed In 2007, we acquired $260.9 million of properties located in our core areas. The largest acquisition involved acquiring additional interests in the Nora field of Virginia, where we entered into a joint development plan with Equitable Resources, Inc. (Equitable). As a result of this transaction, Equitable and Range equalized their working interests in the Nora field, including producing wells, undrilled acreage and gathering systems. Range retained separately owned royalty interests in the field. Equitable operates the producing wells, manages the drilling operations of all future coal bed methane wells and manages the gathering system. Range oversees the drilling of formations below the coal bed methane formations, including tight gas, shale and deeper formations. A newly formed limited liability company, owned 50% by Equitable and 50% by Range, holds the investment in the gathering system.

Successful dispositions completed In February 2007, we sold the Austin Chalk properties for proceeds of $80.4 million. In March 2007, we sold our Gulf of Mexico properties for proceeds of $155.0 million. As a result of these divestitures, we lowered our overall production decline rate and lengthened our reserve life. See Note 4 to our consolidated financial statements.

Plans for 2008

We have announced a $1.1 billion capital budget for 2008, excluding acquisitions. The budget includes $783 million to drill 968 gross (715 net) wells and to undertake 82 gross (66 net) recompletions. Also included is $109 million for land, $51 million for seismic and $122 million for the expansion and enhancement of gathering systems and facilities. Approximately 56% of the budget is attributable to the Southwest Area, 40% to the Appalachia Area and 4% 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 direct operating expenses for the last three years. The information set forth in this table reflects the reclassification of prior year amounts to report the results of operations of our Gulf of Mexico properties sold in the first quarter of 2007 as discontinued operations. 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,		
	2007	2006	2005
Production			
Gas (Mmcf)	89,595	70,713	57,609
Crude oil (Mbbls)	3,360	3,039	2,929
Natural gas liquids (Mbbls)	1,115	1,092	1,012
Total (Mmcfe) [a]	116,441	95,498	81,253
Revenues ($000)			
Gas	$ 613,454	$ 418,183	$ 354,728
Crude oil	202,931	144,251	113,153
Natural gas liquids	46,152	36,705	27,589
Transportation and gathering	2,290	2,422	2,306
Derivative fair value income (loss)	(7,767)	142,395	10,303
Less: Mark-to-market component of derivative fair value income (loss) [c]	79,589	(92,456)	(7,397)
Total	936,649	651,500	500,682
Direct operating expenses [b]	108,741	81,261	57,866
Production and ad valorem taxes	42,443	36,415	30,822
Gross margin	$ 785,465	$ 533,824	$ 411,994
Average sales price (wellhead)			
Gas (per mcf)	$ 6.54	$ 6.59	$ 8.00
Crude oil (per bbl)	67.47	62.36	53.30
Natural gas liquids (per bbl)	41.40	33.62	31.52
Total (per mcfe) [a]	7.37	7.25	7.99
Average realized price (including all derivative settlements)			
Gas (per mcf)	$ 7.66	$ 6.62	$ 6.21
Crude oil (per bbl)	60.16	47.46	38.63
Natural gas liquids (per bbl)	41.40	33.62	27.27
Total (per mcfe) [a]	8.02	6.80	6.13
Operating costs (per mcfe)			
Direct [b]	$ 0.93	$ 0.85	$ 0.71
Production and ad valorem taxes	0.36	0.38	0.38
Total operating costs	$ 1.29	$ 1.23	$ 1.09

Gross margin (per mcfe)	$ 6.74	$ 5.59	$ 5.07

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

(b) 2007 direct operating expenses include $1.8 million (or $0.02 per mcfe) of stock-based compensation. 2006 direct operating expenses include $1.4 million (or $0.01 per mcfe) of stock-based compensation.

(c) By adding this component, the total reflects realized gains (losses) on those derivatives that do not qualify for hedge accounting and excludes unrealized gains (losses) on derivatives that do not qualify for hedge accounting.

Employees

As of January 1, 2008, we had 733 full-time employees, 371 of whom were field personnel. All full-time employees are eligible to receive equity awards approved by the Compensation Committee of the Board of Directors. No employees are covered by a labor union or other collective bargaining arrangement. We believe that the relationship with our employees is excellent. We regularly use independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field, on-site production operation services and certain accounting functions.

Available Information

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

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.

Marketing and Customers

We market nearly all 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 1% 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 500 mcf per day under long-term fixed price contracts. Many contracts contain provisions for periodic price adjustment, termination 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 or upon NYMEX pricing or fixed pricing. All oil pricing is adjusted for quality and transportation. Oil and gas purchasers are selected on the basis of price, credit quality and service. 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 natural gas and oil production are transported primarily through third-party trucks, gathering systems and pipelines. Transportation space on these gathering systems and pipelines is occasionally limited. In Appalachia, we own approximately 5,100 miles of gas gathering pipelines which transport a majority of our Appalachian gas production as well as 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 natural 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, 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, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individuals 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 to make any such statement necessary to make the statements made 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.

Environmental and Occupational Matters

Our operations are subject to stringent federal, state and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments such as the United States Environmental Protection Agency (EPA) issue regulations to implement and enforce such laws, which are often difficult and costly to comply with and 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, limit or prohibit drilling activities 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. In addition, these laws and regulations may restrict the rate of production. The regulatory burden imposed on the oil and gas industry by these laws and regulations increases the cost of doing business, affecting growth and profitability. Changes in environmental laws and regulations occur frequently, and changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect our operations and financial position, as well as the industry in general. We believe we are in substantial compliance with current 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 2007, nor do we anticipate that such expenditures will be material in 2008.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, (CERCLA), 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 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, such 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 and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment pursuant to environmental statutes, common law or both. 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 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. Beyond CERCLA, state laws regulate the disposal of oil and gas wastes, and periodically new state legislative initiatives are proposed that could have a significant impact on us.

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 exists 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 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. Although we used operating and disposal practices that were standard in the industry at the time, 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 wastes 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 analogous state laws. Under such laws, 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 analogous 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 provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other hazardous 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 affect on our operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements 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 actively considering climate change-related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman Warner Climate Security Act or S. 2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. A vote on this bill by the full Senate is expected to occur before mid-year 2008. In addition, at least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has indicated that it will issue a rulemaking notice to address greenhouse gas emissions from vehicles and automobile fuels, although the date for the issuance of this notice has not been finalized. The Court s holding in *Massachusetts* that greenhouse gases fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we conduct business could adversely affect our operations and demand for our products.

We are also subject to the requirements of the federal Occupational Safety and Health Act (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.

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.

Risks Related to Our Business

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

Oil and natural gas prices are volatile, and a decline in prices would adversely affect our profitability and financial condition. The oil and natural gas industry is typically cyclical, and prices for oil and natural gas have been highly volatile. Historically, the industry has experienced severe downturns characterized by oversupply and/or weak demand. Higher oil and natural gas prices have contributed to our positive earnings over the last several years. However, long-term supply and demand for oil and natural 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;
- world-wide economic conditions;
- political conditions in oil and gas producing regions; and
- domestic and foreign governmental regulations.

Decreases in oil and natural gas prices from current levels could adversely affect 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.

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 natural 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
- a sudden, unexpected event materially impacts oil or natural gas prices or the relationship between the hedged price index and the oil and gas sales price.

Information concerning our reserves and future net reserve estimates is uncertain

There are numerous uncertainties inherent in estimating quantities of proved oil and natural 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 natural 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 natural 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 natural gas production;
- the revenues and costs associated with that production; and
- the amount and timing of future development expenditures.

The discounted future net revenues 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 natural gas industry in general.

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

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

Accounting rules require that the carrying value of oil and natural 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 natural gas prices at the time of the impairment review, as well as a 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.

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

Oil and natural 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:

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- 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. Recently, we have experienced substantial increases in premiums especially in areas affected by the 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 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, 2007, approximately 74% of our debt is at fixed interest rates with the remaining 26% subject to variable interest rates. Recent unfavorable disclosures concerning the sub-prime mortgage market may lead to a contraction in credit availability impacting our ability to finance our operations.

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 natural 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

Due to current industry demands, well service providers and related equipment and personnel are in short supply. This is causing escalating prices, the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures will likely 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.

The oil and natural gas industry is subject to extensive regulation

The oil and natural 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 natural gas industry. Compliance with such rules and regulations often increases our cost of doing business 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, in 1997, we consummated a large acquisition that proved extremely disappointing. Production from the acquired properties fell more rapidly than anticipated and further development results were below the results we had originally projected. The poor production performance of these properties resulted in material downward reserve revisions. There is no assurance that our recent and/or future acquisition activity will not result in similarly disappointing results.

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

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

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

Our success is highly dependent on our management personnel, none of which 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.

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

Because the rate of production from oil and natural 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 natural 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 natural 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.

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

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enough oil and natural 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 natural gas prices;
- limitations in the market for oil and natural 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 natural 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 natural gas transportation facilities, most of which are owned by others

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. The unavailability of or 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. Federal and state regulation of oil and natural 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 natural gas.

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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.

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 estimated to range from $1.1 billion to $1.3 billion per year over the next three years, 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;
- breach the numerous financial and other restrictive covenants contained in our existing credit agreements;
- 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.

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 or allege a violation of an existing contract. This action could delay when operations can actually commence or could cause a halt to production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, planned operations could be delayed which would 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 accounting rules and the nature of our business, our financial statements continue to be complex, particularly with reference to hedging, asset retirement obligations, equity awards, deferred taxes and the accounting for our deferred compensation plans. We expect such complexity to continue and possibly increase.

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Risks Related to Our Common Stock

Common stockholders will be diluted if additional shares are issued

Since 1998, we have exchanged 31.9 million shares of common stock for debt and convertible securities. The exchanges were made based on the relative market value of the common stock and the debt and convertible securities at the time of the exchange. Also 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. While the exchanges have reduced interest expense, preferred dividends and future repayment obligations, the larger number of common shares outstanding had a dilutive effect on our existing stockholders. Our ability to repurchase securities for cash is limited by our bank credit facility and our senior subordinated note agreements. 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, 2005 to December 31, 2007, the price of our common stock reported by the New York Stock Exchange ranged from a low of $12.34 per share to a high of $51.88 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 natural 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, 2007. All Gulf of Mexico operations have been reclassified to discontinued operations.

	Average Daily Production (mcfe	Total Production	Percentage of Total	Total Proved Reserves	Percentage of Total Proved

Area	per day)	(mcfe)	Production	(Mmcfe)	Reserves
Southwest	194,060	70,832,032	61%	1,048,314	47%
Appalachia	118,383	43,209,899	37%	1,150,143	52%
Gulf Coast	6,573	2,399,084	2%	34,305	1%
	319,016	116,441,015	100%	2,232,762	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 2,928 net producing wells, 96% of which we operate. Our average working interest is 77%. We have approximately 802,000 gross (536,000 net) acres under lease.

Total proved reserves increased 273.4 Bcfe, or 35%, at December 31, 2007 when compared to year-end 2006. Production was more than offset by property purchases (30.2 Bcfe), drilling additions (293.5 Bcfe) and a favorable reserve revision. Annual production increased 28% over 2006. During 2007, the region spent $506.0 million to drill 290.0 (256.4 net) development wells, of which 282.0 (249.5 net) were productive and 6.0 (3.3 net) exploratory wells, of which 4.0 (2.8 net) were productive. During the year, the region achieved a 97% drilling success rate.

At December 31, 2007, the Southwest Area had a development inventory of 397 proven drilling locations and 367 proven recompletions. During the year, the Southwest Area drilled 76 proven locations and added new locations of 188. 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 Ohio, Pennsylvania, 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 10,800 net producing wells, 59% of which we operate and 5,100 miles of gas gathering lines. Our average working interest is 71%. We have approximately 2.5 million gross (2.1 million net) acres under lease which includes 407,800 acres where we also own a royalty interest.

Reserves at December 31, 2007 increased 235.1 Bcfe, or 26%, from 2006 due to drilling additions (177.4 Bcfe) and property purchases (102.8 Bcfe) which were partially offset by production. Annual production increased 15% over 2006. During 2007, the region spent $278.1 million to drill 654.0 (427.7 net) development wells, of which 653.0 (426.7 net) were productive and 9 (5.5 net) exploratory wells, of which 7.0 (3.5 net) were productive. During the year, the region achieved approximately a 99% drilling success rate. At December 31, 2007, the Appalachia Area had an inventory of 3,600 proven drilling locations and 394 proven recompletions. During the year, the Appalachia Area drilled 321 proven locations and added 755 new locations.

Gulf Coast Area

The Gulf Coast properties are located onshore in Texas, Louisiana and Mississippi. Our major fields produce from 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 126,000 gross (83,000 net) acres under lease. We own 43 net producing wells in this Area, 98% of which we operate. Our average working interest is 57%.

In the first quarter of 2007, we sold all of our offshore properties. Reserves decreased 33.9 Bcfe, or 50%, from 2006 with property sales (37.1 Bcfe), production and an unfavorable reserve revision partially offset by drilling additions (13.3 Bcfe). On an annual basis, production decreased 17% from 2006. During 2007, the region spent $34.8 million to drill 7.0 (4.3 net) development wells, of which all were productive and 1.0 (1.0 net) exploratory well that was not productive. During the year, the Area had a 81% drilling success rate. At December 31, 2007, the Gulf Coast Area had an inventory of 4 proven drilling locations and 16 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, 2007	2006	2005	2004	2003
Natural gas (Mmcf)					
Developed	1,144,709	875,395	724,876	580,006	344,187
Undeveloped	688,088	560,583	400,534	366,422	142,217
Total	1,832,797	1,435,978	1,125,410	946,428	486,404
Oil and NGLs (Mbbls)					
Developed	47,015	37,750	33,029	27,715	24,912
Undeveloped	19,645	15,957	13,863	10,451	8,111
Total	66,660	53,707	46,892	38,166	33,023
Total (Mmcfe) [a]	2,232,762	1,758,226	1,406,762	1,175,425	684,541
% Developed	64%	63%	66%	64%	72%

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

Our percentage of proved developed reserves declined from 2003 to 2004 due to the proved undeveloped reserves acquired in our Great Lakes and Pine Mountain acquisitions which added to our future drilling inventory. From 2004 to 2005, our proved developed percentage increased from 64% to 66% as we continued to drill aggressively. The Stroud acquisition in June of 2006 was primarily responsible for the decrease in the proved developed reserve percentage in 2006. The Stroud acquisition significantly increased our Barnett Shale drilling and prospect inventory. In 2007, the percentage of proved developed reserves increased 1% to 64%.

The following table sets forth summary information by area with respect to estimated proved reserves at December 31, 2007:

	PV-10 [a]		Reserve Volumes			
	Amount (In thousands)	%	Oil & NGL (Mbbls)	Natural Gas (Mmcf)	Total (Mmcfe)	%
Southwest	$ 2,942,845	57%	51,816	737,419	1,048,314	47%
Appalachia	2,128,982	41%	13,742	1,067,691	1,150,143	52%
Gulf Coast	132,997	2%	1,102	27,687	34,305	1%
Total	$ 5,204,824	100%	66,660	1,832,797	2,232,762	100%

(a) PV-10 was prepared using prices in effect at the end of 2007, 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 corporate future income taxes and our current tax structure. While the standardized 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 $1.5 billion at December 31, 2007.

At year-end 2006, 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, 2007, these consultants collectively reviewed approximately 86% 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, 2007 with any federal authority or agency with respect to our estimates of oil and natural gas reserves.

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

	December 31,				
	2007	2006	2005	2004	2003
Future net revenue	$11,908	$6,391	$10,429	$5,035	$2,687
Present value					
Before income tax	5,205	2,771	4,887	2,396	1,396
After income tax (Standardized Measure)	3,666	2,002	3,384	1,749	1,003
Benchmark prices					
Oil price (per barrel)	$ 95.98	$61.05	$ 61.04	$43.33	$32.52
Gas price (per mcf)	$ 6.80	$ 5.64	$ 10.08	$ 6.18	$ 6.19
Wellhead prices					
Oil price (per barrel)	$ 91.88	$57.66	$ 57.80	$40.44	$29.48
Gas price (per mcf)	$ 6.44	$ 5.24	$ 9.83	$ 6.05	$ 6.03

Future net revenues 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 and prices and costs will not 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, 2007. We also own royalty interests in an additional 1,649 wells where 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 natural 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	16,253	11,341	70%
Crude oil	2,832	2,474	87%
Total	19,085	13,815	72%

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

Acreage

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

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The following table sets forth certain information regarding our developed and undeveloped acreage in which we own a working interest as of December 31, 2007. 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			65,617	54,451	65,617	54,451
Louisiana	3,289	2,058	17,454	8,457	20,743	10,515
Michigan	162	162	855	378	1,017	540
Mississippi	3,954	2,167	25,214	7,956	29,168	10,123
New York	187,124	177,871	146,302	128,361	333,426	306,232
Ohio	270,638	254,257	239,569	217,959	510,207	472,216
Oklahoma	160,588	100,855	147,523	79,200	308,111	180,055
Pennsylvania	427,516	388,947	632,448	532,328	1,059,964	921,275
Texas	179,500	146,680	324,180	236,906	503,680	383,586
Virginia	152,300	50,330	166,134	74,393	318,434	124,723
West Virginia	48,468	47,883	107,300	104,300	155,768	152,183
	1,433,539	1,171,210	1,872,596	1,444,689	3,306,135	2,615,899
Average working interest		82%		77%		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
2008	157,342	123,432	8%
2009	244,817	173,246	11%
2010	299,460	219,017	14%
2011	162,742	136,695	9%
2012	303,922	250,387	16%

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, 2007, we were in the process of drilling 131 gross (83 net) wells.

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	942.0	680.5	992.0	689.7	813.0	573.8
Dry	9.0	7.9	8.0	4.6	10.0	7.7
Exploratory wells						
Productive	11.0	6.3	12.0	6.9	13.0	8.1
Dry	5.0	3.5	5.0	2.6	5.0	3.9
Total wells						
Productive	953.0	686.8	1,004.0	696.6	826.0	581.9
Dry	14.0	11.4	13.0	7.2	15.0	11.6

Total	967.0	698.2	1,017.0	703.8	841.0	593.5
Success ratio	99%	98%	99%	99%	98%	98%

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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

burdens such as 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 the fourth quarter of 2007.

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 2007, trading volume averaged 1.6 million shares per day. On December 20, 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
2006			
First quarter	$30.52	$22.52	$ 0.02
Second quarter	30.29	21.74	0.02
Third quarter	30.37	23.38	0.02
Fourth quarter	31.77	22.80	0.03
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

Between January 1, 2008 and February 20, 2008, the common stock traded at prices between $43.02 and $64.50 per share. Our senior subordinated notes are not listed on an exchange, but trade over-the-counter.

Holders of Record

On February 20, 2008, there were approximately 1,848 holders of record of our common stock.

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Dividends

In December 2007, the Board of Directors increased our quarterly dividend to $0.04 per common share. 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 2006 for the repurchase of up to $10.0 million of common stock based on market conditions and opportunities. There were no repurchases during the fourth quarter of 2007. As of December 31, 2007, we have $4.7 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 the common stock, the Dow Jones U.S. Exploration and Production Index and the S&P 500 Index for the five years ended December 31, 2007. The graph assumes that $100 was invested in the Company s common stock and each index on December 31, 2002.

Comparison of Five Year Cumulative Returns

	2002	2003	2004	2005	2006	2007
Range Resources Corporation	$100	$175	$379	$732	$762	$1,427
DJ U.S. Expl. & Prod. Index	100	129	182	298	312	445
S&P 500	100	126	138	141	161	167

* 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, 2007. 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 the reclassification of our Gulf of Mexico operations to 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,				
	2007	2006	2005	2004	2003
	(in thousands, except per share data)				
Balance Sheet Data:					
Current assets [(a)]	$ 261,814	$ 388,925	$ 207,977	$ 136,336	$ 66,092
Current liabilities [(b)]	305,433	251,685	321,760	177,162	106,964
Oil and gas properties, net	3,503,808	2,608,088	1,679,593	1,340,077	658,798
Total assets	4,016,508	3,187,674	2,018,985	1,595,406	830,091
Bank debt	303,500	452,000	269,200	423,900	178,200
Subordinated notes	847,158	596,782	346,948	196,656	109,980
Stockholders equity [(c)]	1,728,022	1,256,161	696,923	566,340	274,066
Weighted average dilutive shares outstanding	149,911	138,711	129,125	97,998	86,775
Cash dividends declared per common share	0.13	0.09	.0599	.0267	.0067
Cash Flow Data:					
Net cash provided from operating activities	$ 642,291	$ 479,875	$ 325,745	$ 209,249	$124,680
Net cash used in investing activities	1,020,572	911,659	432,377	624,301	186,838
Net cash provided from financing activities	379,917	429,416	93,000	432,803	61,455

(a) 2007 included deferred tax assets of $26.9 million. 2005 included deferred tax assets of $61.7 million compared to $26.3 million in 2004 and $19.9 million in 2003. 2007 includes a $53.0 million unrealized derivative asset compared to $93.6 million in 2006.

(b) 2007 includes unrealized derivative liabilities of $30.5 million compared to $4.6 million in 2006, $160.1 million in 2005, $61.0 million in 2004 and $54.3 million in 2003.

(c) Stockholders equity includes other comprehensive income (loss) of ($26.8 million) in 2007 compared to $36.5 million in 2006, ($147.1 million) in 2005, ($43.3 million) in 2004 and ($42.9 million) in 2003.

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Statement of Operations Data:

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(in thousands, except per share data)				
Revenues					
Oil and gas sales	$862,537	$599,139	$495,470	$278,903	$179,074
Transportation and gathering	2,290	2,422	2,306	2,002	3,248
Gain (loss) on retirement of securities				(39)	18,526
Derivative fair value (loss) income	(7,767)	142,395	10,303	614	(1,282)
Other	5,031	856	1,024	1,588	(865)
Total revenue	862,091	744,812	509,103	283,068	198,701
Costs and expenses					
Direct operating	108,741	81,261	57,866	39,419	28,110
Production and ad valorem taxes	42,443	36,415	30,822	19,845	12,059
Exploration	43,345	44,088	29,529	12,619	12,530
General and administrative	68,428	49,886	33,444	20,634	17,818
Deferred compensation plan	28,332	6,873	29,474	19,176	6,559
Interest expense and dividends on trust preferred	77,737	55,849	37,619	22,437	21,507
Depletion, depreciation and amortization	227,328	154,739	114,364	80,628	62,687
Total costs and expenses	596,354	429,111	333,118	214,758	161,270
Income from continuing operations before income taxes and accounting change	265,737	315,701	175,985	68,310	37,431
Income tax provision (benefit)					
Current	320	1,912	1,071	(245)	170
Deferred	98,441	119,840	64,809	25,327	14,125
	98,761	121,752	65,880	25,082	14,295
Income from continuing operations	166,976	193,949	110,105	43,228	23,136
Income (loss) from discontinued operations	63,593	(35,247)	906	(997)	7,788
Income before cumulative effect of changes in accounting	230,569	158,702	111,011	42,231	30,924

principles					
Cumulative effect of changes in accounting principles, net of taxes					4,491
Net income	230,569	158,702	111,011	42,231	35,415
Preferred dividends				(5,163)	(803)
Net income available to common stockholders	$230,569	$158,702	$111,011	$ 37,068	$ 34,612
Earnings per common share:					
Basic income from continuing operations	$ 1.16	$ 1.45	$ 0.89	$ 0.41	$ 0.27
income (loss) from discontinued operations	0.44	(0.26)		(0.01)	0.10
cumulative effect of changes in accounting principles					0.05
net income	$ 1.60	$ 1.19	$ 0.89	$ 0.40	$ 0.42
Diluted income from continuing operations	$ 1.11	$ 1.39	$ 0.85	$ 0.39	$ 0.27
income (loss) from discontinued operations	0.43	(0.25)	0.01	(0.01)	0.09
cumulative effect of changes in accounting principles					0.05
net income	$ 1.54	$ 1.14	$ 0.86	$ 0.38	$ 0.41

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.

Items Impacting the Comparability to Prior Year Reports

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 for all periods presented reflects the reclassification of our Gulf of Mexico operations to discontinued operations.

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. As a mature region, while new discoveries of oil and gas occur in the United States, 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, which are underexplored or have not been fully explored and developed with the benefit of newly available exploration, production and reserve 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.

Another characteristic of a mature region is the historical exit of larger independent producers and major oil companies from such regions. These companies, searching for ever larger new discoveries, have ventured increasingly overseas and offshore, de-emphasizing their onshore United States assets. This movement out of mature basins by larger companies has provided acquisition opportunities for companies like ours that maintain well-equipped technical teams capable of generating additional value from these assets. In other situations, to increase cash flow without increasing capital spending, larger independent producers and major integrated oil companies have allowed smaller companies the opportunity to explore and develop reserves on their undeveloped acreage through joint ventures and farm-in arrangements.

We believe the acquisition market for oil and gas properties has become extremely competitive as producers vie for additional production and expanded drilling opportunities. Acquisition values have reached historic highs and we expect these values to remain high in 2008. In addition, we expect drilling and service costs to remain at a high level in 2008 and for lease operating expenses to continue to rise as producers are forced to make operational enhancements to maintain aging fields.

Oil and gas is a commodity. 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 has increased dramatically over the last ten years. Demand is impacted by general economic conditions, estimates of gas in storage, weather and other seasonal condition, including hurricanes and tropical storms. Market conditions involving 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. A factor impacting the future supply balance is the recent increase in the United States LNG import capacity. Significant LNG capacity increases have been announced which may result 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.

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. The price of oil and natural gas is the primary factor 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 natural gas and oil production. During 2006 and 2005 the use of derivative instruments prevented us from realizing the full benefit of upward price movements and may continue to do so in future periods. Our realized price calculations include 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 workovers and repairs to our oil and gas properties. These costs are expected to remain high in 2008 as the demand for these services continues to increase. Direct operating expenses also include stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R) and amortization of restricted stock grants as part of employee compensation.

Production and Ad Valorem Taxes. These costs are taxes paid on produced oil and gas based on a percentage of market prices (not at hedged prices) or at fixed rates established by federal, state or local taxing authorities.

Exploration Expense. Geological and geophysical costs, including payroll and benefits for the geological and geophysical staff, seismic costs, delay rentals and the costs of unsuccessful exploratory or dry holes. Exploration expense includes stock-based compensation expense (non-cash) associated with the adoption of SFAS No. 123(R) and amortization of restricted stock grants as part of employee compensation.

General and Administrative Expense. Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, 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 the adoption of SFAS No. 123(R) and amortization of restricted stock grants as part of employee compensation.

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 2008 capital budget to be funded primarily with internal cash flow and asset sales.

Depreciation, Depletion and Amortization. The systematic expensing of the capitalized costs incurred to acquire, explore and develop natural 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 includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines, and other facilities. This category also includes unproved property impairment and costs associated with lease expirations.

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 2007 Results

During 2007, we achieved the following results:

- Achieved 22% production growth and 27% reserve growth;
- Drilled 698 net wells;
- Continued expansion of drilling inventory and emerging plays;
- Posted record financial results and continued balance sheet improvements; and
- Completed acquisitions of properties containing 133 Bcfe of proved reserves.

Our 2007 performance reflects another year of successfully executing our strategy of growth through drilling and 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 the operation are critical to profitability and long-term value creation for stockholders. Generating meaningful growth while containing costs presents an ongoing challenge. During periods of historically high oil and gas prices, drilling service and operating cost increases are more prevalent due to increased competition for goods and services. We faced other challenges in 2007 including attracting and retaining qualified personnel, consummating and integrating acquisitions, and accessing the capital markets to fund our growth on sufficiently favorable terms. 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 16% in 2007 over the same period of 2006. This increase is due to higher production and higher realized oil and gas prices. Our 2007 production growth is due to the continued success of our drilling program and to acquisitions completed in 2006 and 2007. Realized prices were higher by 18% in 2007. As discussed in Item 1A of this report, significant changes in oil and gas prices can have a significant impact on our balance sheet and our results of operations, including the fair value of our derivatives.

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 commodity prices or volumes of production sold. Hedges realized reflect settlements on those derivatives that qualify for hedge accounting. Oil and gas sales increased 44% from 2006 due to a 22% increase in production and an 18% increase in realized prices. Oil and gas sales in 2006 increased 21% from 2005 due to an 18% increase in production and a 3% 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):

	2007	2006	2005
Oil and Gas Sales			
Oil wellhead	$ 226,686	$ 189,516	$ 156,102
Oil hedges realized	(23,755)	(45,265)	(42,948)
Total oil revenue	$ 202,931	$ 144,251	$ 113,154
Gas wellhead	$ 585,538	$ 466,099	$ 461,132
Gas hedges realized	27,916	(47,916)	(106,404)
Total gas revenue	$ 613,454	$ 418,183	$ 354,728
NGL	$ 46,152	$ 36,705	$ 31,891

NGL hedges realized			(4,302)
Total NGL revenue	$ 46,152	$ 36,705	$ 27,589
Combined wellhead	$ 858,376	$ 692,320	$ 649,126
Combined hedges	4,161	(93,181)	(153,655)
Total oil and gas sales	$ 862,537	$ 599,139	$ 495,471

Our production continues to grow through continued drilling success and additions from acquisitions. 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:

	2007	2006	2005
Production			
Crude oil (bbls)	3,359,668	3,039,150	2,929,013
NGLs (bbls)	1,114,730	1,091,785	1,011,692
Natural gas (mcf)	89,594,626	70,712,770	57,608,816
Total (mcfe) [a]	116,441,014	95,498,380	81,253,046
Average daily production			
Crude oil (bbls)	9,205	8,326	8,025
NGLs (bbls)	3,054	2,991	2,772
Natural gas (mcf)	245,465	193,734	157,832
Total (mcfe) [a]	319,016	261,639	222,611

[a] Oil and NGLs are converted to mcfe at the rate of one barrel equals six mcfe.

Our average realized price (including all derivative settlements) received for oil and gas during 2007 was $8.02 per mcfe compared to $6.80 per mcfe in 2006 and $6.13 per mcfe in 2005. Our average realized price calculation (including all derivative settlements) 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:

	2007	2006	2005
Average Prices			
Average sales prices (wellhead):			
Crude oil (per bbl)	$67.47	$62.36	$53.30
NGLs (per bbl)	$41.40	$33.62	$31.52
Natural gas (per mcf)	$ 6.54	$ 6.59	$ 8.00
Total (per mcfe) [a]	$ 7.37	$ 7.25	$ 7.99
Average realized prices (including derivatives that qualify for hedge accounting):			
Crude oil (per bbl)	$60.40	$47.46	$38.63
NGLs (per bbl)	$41.40	$33.62	$27.27
Natural gas (per mcf)	$ 6.85	$ 5.91	$ 6.16
Total (per mcfe) [a]	$ 7.41	$ 6.27	$ 6.10
Average realized prices (including all derivative settlements):			
Crude oil (per bbl)	$60.16	$47.46	$38.63
NGLs (per bbl)	$41.40	$33.62	$27.27
Natural gas (per mcf)	$ 7.66	$ 6.62	$ 6.21

Total (per mcfe) [(a)]	$ 8.02	$ 6.80	$ 6.13
Average NYMEX prices [(b)]:			
Oil (per bbl)	$72.34	$66.22	$56.56
Natural gas (per mcf)	$ 6.92	$ 7.26	$ 8.55

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

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

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Derivative fair value income (loss) decreased to a loss of $7.8 million in 2007 compared to a gain of $142.4 million in 2006 and a gain of $10.3 million in 2005. In the fourth quarter of 2005, certain of our gas hedges no longer qualified for hedge accounting due to the effect of gas price volatility on the correlation between realized prices and hedge reference prices. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, the portion of our derivatives which were designated to our Gulf of Mexico production was marked to market resulting in fair value income of $209,000. In the fourth quarter of 2007, we began marking a portion of our oil hedges designated as Permian Basin production to market due to the anticipated sale of a portion of our Permian properties resulting in derivative fair value loss of $14.7 million. The loss of hedge accounting treatment creates volatility in our revenues as gains and losses from non-hedge derivatives are included in total revenues and are not included in our balance sheet in accumulated other compensation 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 prices increased dramatically in 2007, our derivatives became comparatively less valuable. However, we expect these losses will be offset by higher wellhead revenues in the future. Beginning in the third quarter of 2007, we have also entered into basis swap agreements which do not qualify for hedge accounting purposes and are marked to market. Hedge ineffectiveness included in this category 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, 2007 (in thousands):

	2007	2006	2005
Hedge ineffectiveness realized	$ 968	$	$
unrealized [(a)]	(820)	5,965	(3,471)
Change in fair value of derivatives that do not qualify for hedge accounting [(a)]	(78,769)	86,491	10,868
Realized gain on settlements gas [(b)]	71,098	49,939	2,906
Realized loss on settlements oil [(b)]	(244)		
Derivative fair value (loss) income	$ (7,767)	$ 142,395	$ 10,303

(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 which before settlement have been recognized in the unrealized mark-to-market component of derivative fair value income (loss). These settlements are included in average realized price calculations (including all derivative settlements).

Other revenue increased in 2007 to a gain of $5.0 million compared to a gain of $856,000 in 2006 and a gain of $1.0 million in 2005. 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. The 2005 period includes income of $514,000 from Independent Producer Finance, one of our businesses that no longer operates.

Comparison of 2007 and 2006 Expenses

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

Operating expenses (per mcfe)	2007	2006	Change	% Change
Direct operating expense	$0.93	$0.85	$ 0.08	9%
Production and ad valorem tax expense	0.36	0.38	(0.02)	5%
General and administrative expense	0.59	0.52	0.07	13%
Interest expense	0.67	0.58	0.09	15%
Depletion, depreciation and amortization expense	1.95	1.62	0.33	20%

Direct operating expense for 2007 increased $27.5 million, or 33.8%, to $108.7 million due to higher oilfield service costs, higher volumes and the integration of our recent acquisitions. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. On a per mcfe basis, direct operating expenses were $0.93 and increased $0.08 from 2006 with the increase consisting primarily of higher water disposal costs ($0.02 per mcfe), higher well services and equipment costs ($0.04 per mcfe), higher workover costs ($0.02 per mcfe) and a $0.01 per mcfe increase in stock- based compensation. The following table summarizes direct operating expenses per mcfe for 2007 and 2006:

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	2007	2006	Change	% Change
Lease operating expense	$ 0.85	$ 0.80	$ 0.05	6%
Workovers	0.06	0.04	0.02	50%
Stock-based compensation	0.02	0.01	0.01	100%
Total direct operating expenses	$ 0.93	$ 0.85	$ 0.08	9%

Production and ad valorem taxes are paid based on market prices and not hedged prices. For 2007, these taxes increased $6.0 million, or 17%, from the same period of the prior year. On a per mcfe basis, production and ad valorem taxes decreased from $0.38 in 2006 to $0.36 in 2007 with lower ad valorem taxes per mcfe due to lower property tax rates in Texas as a result of the new margin tax.

General and administrative expense for 2007 increased $18.5 million, or 37%, primarily due to higher salaries and benefits of $9.2 million ($0.03 per mcfe), higher office rent and general office expense of $2.3 million ($0.01 per mcfe) and higher stock based compensation of $4.0 million ($0.01 per mcfe). The stock-based compensation expense represents amortization of restricted stock grants and stock option/SARs expense under SFAS No. 123(R). On a per mcfe basis, general and administration expense increased from $0.52 in 2006 to $0.59 in 2007. The following table summarizes general and administrative expenses per mcfe for 2007 and 2006:

	2007	2006	Change	% Change
General and administrative	$ 0.43	$ 0.37	$ 0.06	16%
Stock-based compensation	0.16	0.15	0.01	7%
Total general and administrative expenses	$ 0.59	$ 0.52	$ 0.07	13%

Interest expense for 2007 increased $21.9 million, or 39%, to $77.7 million with higher average debt balances and the refinancing of certain debt from short-term floating to longer-term fixed rates. In September 2007, we issued $250.0 million of 7.5% senior subordinated notes due 2017 which added $4.8 million of interest costs in 2007. In May 2006, we issued $250.0 million of 7.5% senior subordinated notes due 2016 which increased interest expense by $9.1 million in 2007. The proceeds from these issuances were used to retire shorter term lower rate bank debt. In 2007, the average debt outstanding on the bank credit facility was $417.6 million with an average interest rate of 6.4% compared to an average debt outstanding in 2006 of $347.8 million, with an average interest rates of 6.4%.

Depletion, depreciation and amortization (DD&A) for 2007 increased $72.6 million, or 47%, to $227.3 million, due to higher production and higher depletion rates. Depletion rates increased 16%, or $0.24 per mcfe, due to increased drilling costs and the mix of our production. DD&A increased from $1.62 per mcfe in 2006 to $1.95 per mcfe in 2007. For 2008, based on our current reserve base, we expect our DD&A rate to average approximately $2.10 per mcfe. The twelve months ended 2007 also includes higher unproved property impairment of $3.0 million ($0.03 per mcfe), higher acreage expiration expense of $3.4 million ($0.03 per mcfe), higher accretion expense related to asset retirement obligations of $2.3 million ($0.01 per mcfe) and higher depreciation expense of $3.3 million ($0.01 per mcfe). In the fourth quarter of 2006, we lowered our salvage value estimates on our Appalachia wells which increased DD&A expense by $4.6 million.

Our operating expenses also include other expenses that generally do not trend with production. These expenses include stock-based compensation, exploration expense and deferred compensation plan expense. In 2007, stock-based compensation of $24.0 million is a component of direct operating expense ($1.8 million), exploration expense ($3.5 million) and general and administrative expense ($18.2 million). In 2006, stock-based compensation of $19.1 million is a component of direct operating expense ($1.4 million), exploration expense ($3.1 million) and general and administrative expense ($14.3 million). In 2007 and 2006, this expense represents the amortization of restricted stock grants, stock options and SARs as they become vested.

Exploration expense for 2007 decreased $743,000, or 2%, to $43.3 million due to lower seismic costs ($4.3 million) somewhat offset by higher personnel costs. The following table details our exploration-related expenses (in thousands):

	2007	2006	Change	% Change
Dry hole expense	$ 15,149	$ 15,084	$ 65	
Seismic	10,933	15,277	(4,344)	28%
Personnel expense	8,924	6,917	2,007	29%
Stock-based compensation expense	3,473	3,079	394	13%
Delay rentals and other	4,866	3,731	1,135	30%
Total exploration expense	$ 43,345	$ 44,088	$ (743)	2%

Deferred compensation plan expense for 2007 increased to $28.3 million, or 312%, from $6.9 million in 2006. This non-cash expense relates to the increase or decrease in value of our common stock and other investments held in our deferred compensation plans. In the fourth quarter of 2007, we recorded adjustments that decreased deferred compensation plan expense by $12.4 million. Such adjustments were the result of an incorrect practice of adjusting our deferred compensation liability for market value changes in unvested shares held in our deferred compensation plan. In addition, interest and dividends related to the marketable securities held in the deferred compensation plan were inappropriately recorded in accumulated other comprehensive loss. Of the $12.4 million decrease in deferred compensation expense, $7.1 million is related to periods prior to 2007 and $5.3 million is related to the first three quarters of 2007. Our common stock price increased from $26.34 per share at the end of 2005 to $27.46 per share at the end of 2006 to $51.36 per share at the end of 2007.

Income tax expense for 2007 decreased $23.0 million, or 19%, to $98.8 million due to a 16% decrease in income from continuing operations. Our effective tax rate was 37% for 2007 compared to 39% for 2006. The twelve months ended December 31, 2007 includes a non-recurring $3.0 million tax benefit related to an increase in the Texas Margin Tax credit carryover. This benefit is related to a change in the Texas law allowing companies to realize tax attributes carrying forward from the previously applicable Texas Franchise tax to the new Texas Margin tax. The twelve months ended December 31, 2006 includes a $2.8 million tax expense for changes in state tax rates. We expect our effective tax rate to be approximately 37% for 2008. Given our available net operating loss carryover, we do not expect to pay significant federal income taxes. We received a refund of $299,000 for state income taxes in 2007.

Discontinued operations includes the operating results related to our Gulf of Mexico properties and Austin Chalk properties that we sold in the first quarter of 2007. See also Note 4 to our consolidated financial statements.

Comparison of 2006 to 2005 Expenses

Our unit costs have increased as we continue to grow. We believe some of our expense fluctuations should be analyzed on a unit of production, or per mcfe basis. The following table presents information about certain of our operating expenses on a per mcfe basis for 2006 and 2005:

Operating expenses (per mcfe)	2006	2005	Change	% Change
Direct operating expense	$ 0.85	$ 0.71	$ 0.14	20%
Production and ad valorem tax expense	0.38	0.38		
General and administration expense	0.52	0.41	0.11	27%
Interest expense	0.58	0.46	0.12	26%
Depletion, depreciation and amortization expense	1.62	1.41	0.21	15%

Direct operating expense for 2006 increased $23.4 million to $81.3 million due to higher oilfield service costs, higher volumes and the integration of our recent acquisitions. Our operating expenses are increasing as we add new wells and maintain production from our existing properties. On a per mcfe basis, direct operating expenses were $0.85

and increased 20% or $0.14 from 2005 consisting of higher utilities ($0.01 per mcfe), higher water disposal and equipment costs ($0.06 per mcfe) and higher pumper expenses ($0.01 per mcfe). The following table summarizes direct operating expenses per mcfe for 2006 and 2005:

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	2006	2005	Change	% Change
Lease operating	$ 0.80	$ 0.66	$ 0.14	21%
Workovers	0.04	0.04		%
Stock-based compensation	0.01	0.01		%
Total direct operating expenses	$ 0.85	$ 0.71	$ 0.14	20%

Production and ad valorem taxes are paid based on market prices and not hedged prices. For 2006, these taxes increased $5.6 million, or 18%, from the same period of the prior year. On a per mcfe basis, production and ad valorem taxes remained the same at $0.38.

General and administrative expense for 2006 increased $16.4 million, or 49%, to 49.9 million, from 2005 due primarily to higher salaries and benefits of $6.0 million ($0.03 per mcfe), higher office rent and general office expenses of $1.0 million ($0.01 per mcfe) and higher stock-based compensation expense of $9.4 million ($0.09 per mcfe). The stock-based compensation expense represents amortization of restricted stock grants in 2006 and 2005, expense related to the adoption of SFAS No. 123(R) in 2006 and the mark-to-market of SARs granted to employees in 2005. On a per mcfe basis, general and administration expense increased 27% from $0.41 in 2005 to $0.52 in 2006. The following table summarizes general and administrative expenses per mcfe for 2006 and 2005:

	2006	2005	Change	% Change
General and administrative expense	$ 0.37	$ 0.35	$ 0.02	6%
Stock-based compensation	0.15	0.06	0.09	150%
Total general and administrative expenses	$ 0.52	$ 0.41	$ 0.11	27%

Interest expense for 2006 increased $18.2 million, or 48%, to $55.8 million with higher average interest rates, higher average debt balances and the refinancing of certain debt from short-term floating to longer-term fixed rates. In May 2006, we issued $250.0 million of 7.5% senior subordinated notes which added $9.7 million of interest costs. The proceeds from this issuance were used to retire shorter term bank debt. Average debt outstanding on the bank credit facility was $347.8 million with an average interest rate of 6.4% compared to an average debt outstanding in 2005 of $314.8 million with an average interest rate of 4.5%.

Depletion, depreciation and amortization for 2006 increased $40.4 million, or 35%, to $154.7 million due to higher production and higher depletion rates. DD&A increased from $1.41 per mcfe in 2005 to $1.62 per mcfe in 2006. This increase is primarily related to our Stroud acquisition, increasing drilling costs and the mix of our production. In the fourth quarter of 2006, we lowered our salvage value estimates on our Appalachia wells which increased DD&A expense by $4.6 million.

Operating expenses also include stock-based compensation, exploration expense and deferred compensation plan expenses that generally do not trend with production. In 2006, stock-based compensation expense is a component of direct operating expense ($1.4 million), exploration expense ($3.1 million) and general and administrative expense ($14.3 million) and a $320,000 reduction of gas transportation revenues for a total of $19.1 million. In 2005, stock-based compensation is a component of direct operating expense ($480,000), exploration expense ($1.2 million) and general and administrative expense ($4.9 million) and a reduction of $117,000 of gas transportation revenues for a total of $6.7 million. This expense represents the amortization of restricted stock grants in 2006 and 2005, expense related to the adoption of SFAS No. 123(R) in 2006 and in 2005, the mark-to-market of SARs granted to employees.

Exploration expense increased 49% to $44.1 million due to higher seismic costs ($2.0 million), higher dry hole costs ($8.5 million) and higher personnel costs. The following table details our exploration-related expenses (in thousands):

	2006	2005	Change	% Change
Dry hole expense	$ 15,084	$ 6,560	$ 8,524	130%
Seismic	15,277	13,292	1,985	15%
Personnel expense	6,917	5,872	1,045	18%
Stock-based compensation expense	3,079	1,250	1,829	146%
Other	3,731	2,555	1,176	46%
Total exploration expense	$ 44,088	$ 29,529	$ 14,559	49%

Deferred compensation plan expense for 2006 decreased $22.6 million, or 77%, to $6.9 million. This non-cash expense relates to the increase or decrease in value of our common stock and other investments held in our deferred compensation plans. Our common stock price increased from $13.64 per share at the end of 2004 to $26.34 per share at the end of 2005 to $27.46 per share at the end of 2006.

Tax expense for 2006 increased $55.9 million, or 85%, to $121.8 million due to a 79% increase in income from continuing operations. Our effective tax rate was 39% for 2006 compared to 37% in 2005. Given our available net operating loss carryforward, we do not expect to pay significant federal income taxes. The twelve months ended December 31, 2006 includes a $2.8 million adjustment for changes in state tax rates. We paid $1.8 million of state taxes in 2006.

Discontinued operations for 2006 and 2005 includes the results of operations for our Gulf of Mexico assets which were sold in the first quarter of 2007. Discontinued operations for 2006 also includes the operating results and impairment losses on the Austin Chalk properties which were acquired as part of our 2006 Stroud acquisition. Due to significant price declines after the purchase of these properties and volumes produced since the acquisition, we recognized an impairment of $74.9 million. These properties were also sold in the first quarter of 2007. See also Note 4 to our consolidated financial statements.

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

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a committed bank credit facility, asset sales and access to both the debt and equity capital markets. During 2007, our net cash provided from continuing operations of $632.1 million, proceeds from our April 2007 common stock offering of $280.4 million, proceeds from our September 2007 note offering of $250.0 million and proceeds from the sale of assets of $234.3 million were used to fund $1.2 billion of capital expenditures (including acquisitions and equity investments). At December 31, 2007 we had $4.0 million in cash and total assets of $4.0 billion. Our debt to capitalization ratio was 40.0% at December 31, 2007 compared to 45.5% at December 31, 2006. As of December 31, 2007 and 2006, our total capitalization was as follows (in thousands):

	2007	2006
Bank debt	$ 303,500	$ 452,000
Senior subordinated notes	847,158	596,782
Total debt	1,150,658	1,048,782
Stockholders equity	1,728,022	1,256,161
Total capitalization	$ 2,878,680	$ 2,304,943
Debt to capitalization ratio	40%	46%

Long-term debt at December 31, 2007 totaled $1.2 billion, including $303.5 million of bank credit facility debt and $847.2 million of senior subordinated notes. Our available borrowing capacity at December 31, 2007 was $596.5 million. Cash is required to fund capital expenditures necessary to offset inherent declines in production and reserves which is typical in the oil and gas industry. Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We believe that net cash generated from operating activities and unused committed borrowing capacity under the bank credit facility combined with our oil and gas price hedges currently in place will be adequate to satisfy near term financial obligations and liquidity needs. However, long-term cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. A material drop in oil and gas prices or a reduction in production and reserves would reduce our ability to fund capital expenditures, reduce debt, meet financial obligations and remain profitable. We operate in an environment with numerous financial and operating risks, including, but not limited to, the inherent risks of the search for, development and production of oil and gas, the ability to buy properties and sell production at prices which provide an attractive return and the highly competitive nature of the industry. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proved reserves.

Bank Debt

We maintain a $900.0 million revolving credit facility, which we refer to as our bank debt or our bank credit facility. The bank credit facility is secured by substantially all of our assets and matures on October 25, 2012. Availability under the bank credit facility is subject to a borrowing base set by the lenders semi-annually with an option to set more often in certain circumstances. The borrowing base is dependent on a number of factors, primarily the lenders assessment of future cash flows. Redeterminations of the borrowing base require approval of 75% of the lenders; increases require unanimous approval.

At February 20, 2008, the bank credit facility had a $1.5 billion borrowing base and a $900.0 million facility amount. Credit availability is equal to the lesser of the facility amount or the borrowing base resulting in credit availability of $300.5 million on February 20, 2008. The facility amount can be increased to the borrowing base with twenty days notice.

Our bank debt and our subordinated notes impose limitations on the payment of dividends and other restricted payments (as defined under the debt agreements for our bank debt and our subordinated notes). Under the bank credit facility, common and preferred dividends are permitted. The terms of each of our subordinated notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings and equity issuances since the original issuances of the notes. The 7.5% senior subordinated notes due in 2016 and 2017 also allow for any cash proceeds received within twelve months from the sale of oil and gas properties purchased in an acquisition using stock as consideration to be added to the restricted payment basket. At December 31, 2007, approximately $922.4 million was available under the restricted payment baskets for each of the 7.375% senior subordinated notes, 6.375% senior subordinated notes and the $7.5% senior subordinated notes due in 2017. There was $1.0 billion available under the restricted payment basket for the 7.5% senior subordinated notes due 2016. The bank credit facility provides for a restricted payment basket of $20.0 million plus 66-2/3% of net cash proceeds from common stock issuances and 50% of net income. Approximately $735.2 million was available under the bank credit facility restricted payment basket as of December 31, 2007. The debt agreements contain customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2007.

Cash Flow

Our principal sources of cash are operating cash flow, bank borrowings, asset sales and at times, issuance of debt and equity securities. Our operating cash flow is highly dependent on oil and gas prices. As of December 31, 2007, we had entered into hedging agreements covering 102.1 Bcfe for 2008 and 61.3 Bcfe for 2009. The $808.4 million of cash capital expenditures for 2007, excluding acquisitions, was funded with internal cash flow and proceeds from asset sales. The $1.1 billion capital budget for 2008, which excludes acquisitions, is expected to increase production and to expand the reserve base. Based on current projections, oil and gas futures prices and our hedge position, the 2008 capital program is expected to be funded, primarily with internal cash flow and asset sales.

Net cash provided from continuing operations in 2007 was $632.1 million, compared to $441.5 million in 2006 and $288.6 million in 2005. In 2007, cash flow from continuing operations increased due to higher production volumes and higher realized prices partially offset by increasing operating costs. In 2006, cash flow from operations increased due to higher production volumes and prices partially offset by increasing operating, exploration and interest expenses. In 2005, cash flow from operations increased due to higher volumes and prices partially offset by increasing operating costs.

Net cash used in investing activities in 2007 was $1.0 billion, compared to $911.7 million in 2006 and $432.4 million in 2005. In 2007, we spent $782.4 million in additions to oil and gas properties, $336.5 million on acquisitions and $94.7 on equity method investments. Also in 2007, we recognized proceeds of $234.3 million from the sale of assets. The 2006 period included $487.2 million in additions to oil and gas properties and $360.1 million of acquisitions. The 2005 period included $266.4 million in additions to oil and gas properties and $153.6 million of acquisitions.

Net cash provided from financing activities in 2007 was $379.9 million, compared to $429.4 million in 2006 and $93.0 million in 2005. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. During 2007, we received proceeds of $250.0 million from the issuance of our 7.5% senior subordinated notes due 2017 and proceeds of $280.4 million from a common stock offering. During 2006, we received proceeds of $249.5 million from the issuance of our 7.5% senior subordinated notes due 2016. During 2005, the outstanding balance under our bank credit facility declined $154.7 million primarily due to the proceeds received from the 6.375% senior subordinated notes due 2017 being applied to our bank debt. During 2005, we also received proceeds of $109.2 million from a common stock offering.

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of oil and gas properties, repayment of principal and interest on outstanding debt and payment of dividends. During 2007, $820.0 million of capital was expended on drilling projects. Also in 2007, $339.0 million was expended on acquisitions primarily to purchase additional interests in producing properties and unproved acreage. The capital program, excluding acquisitions, was funded by net cash flow from operations and proceeds from asset sales. The 2008 capital budget of $1.1 billion, excluding acquisitions, is expected to be funded primarily by cash flow from operations and asset sales. Development and exploration activities are highly discretionary, and, for the foreseeable future, we expect such activities to be maintained at levels equal to internal cash flow and asset sales. To the extent capital requirements exceed internal cash flow and proceeds from asset sales, debt or equity may be issued to fund these requirements. We currently believe we have sufficient liquidity and cash flow to meet our obligations for the next twelve months; however, a drop in oil and gas prices or a reduction in production or reserves could adversely affect our ability to fund capital expenditures and meet our financial obligations. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may issue additional shares of stock, subordinated notes or other debt securities to fund capital expenditures, acquisitions, extend maturities or to repay debt.

Cash Dividend Payments

The amount of future dividends is subject to declaration by the Board of Directors and primarily depends on earnings and capital expenditures. In 2007, we paid $19.1 million in dividends to our common shareholders ($0.04 per share in the fourth quarter and $0.03 per share in the third, second and first quarters). In 2006, we paid $12.2 million in dividends to our common stockholders ($0.03 per share in the fourth quarter and $0.02 per share in the third, second and first quarters). In 2005, we paid $7.6 million in dividends to our common stockholders ($0.0133 per share in the second and third quarters and $0.02 per share in the fourth quarter). Also in 2005, we paid $2.2 million in preferred stock dividends.

Future Commitments

In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. As of December 31, 2007, we do not have any capital leases nor have we entered into any material long-term contracts for equipment. As of December 31, 2007, we do not have any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed the debt of any other party. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2007. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2007 reflects accrued interest payable on our bank debt of $739,000 which is payable in the first quarter of 2008. We expect to make annual interest payments of $14.8 million per year on our 7.375% senior subordinated notes, $18.8 million per year on our 7.5% senior subordinated notes due 2016, $9.6 million per year on our 6.375% senior subordinated notes and $18.8 million per year on our 7.5% senior subordinated notes due 2017.

The following summarizes our contractual financial obligations at December 31, 2007 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our bank credit facility and proceeds from asset sales.

			Payment due by period		
	2008	2009 and 2010	2011 and 2012	Thereafter	Total
			(in thousands)		
Bank debt due 2012	$	$	$ 303,500(a)	$	$ 303,500
7.375% senior subordinated notes due 2013				200,000	200,000
6.375% senior subordinated notes due 2015				150,000	150,000
7.5% senior subordinated notes due 2016				250,000	250,000
7.5% senior subordinated notes due 2017				250,000	250,000
Operating leases	9,657	19,221	12,801	8,568	50,247
Seismic agreements	500	300			800
Derivative obligations (b)	30,457	45,819			76,276
Asset retirement obligation liability	1,903	9,816	2,538	61,051	75,308
Total contractual obligations (c)	$ 42,517	$ 75,156	$ 318,839	$ 919,619	$ 1,356,131

(a) Due at termination date of our bank credit facility. We expect to renew our bank credit facility, but there is no assurance that can be accomplished. Interest paid on our bank credit facility would be approximately $28.0 million each year assuming no change in the interest rate or outstanding balance.

(b) Derivative obligations represent net open derivative contracts valued as of December 31, 2007. While such payments will be funded by higher prices received from the sale of our production, production receipts may be received after our payments to counterparties which can result in borrowings under our bank credit facility.

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

Hedging Oil and Gas Prices

We enter into derivative agreements to reduce the impact of oil and gas price volatility. At December 31, 2007, swaps were in place covering 71.3 Bcf of gas at prices averaging $8.82 per mcf. We also had collars covering 54.8 Bcf of gas at weighted average floor and cap prices of $8.07 to $9.73 and 6.2 million barrels of oil at weighted average floor and cap prices of $61.54 to $75.72. The derivative fair value, represented by the estimated amount that would be realized or payable on termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a pretax loss of $22.3 million at December 31, 2007. The contracts expire monthly through December 2009. Settled transaction gains and losses for derivatives that qualify for hedge accounting are determined monthly and are included as increases or decreases on oil and gas sales in the period the hedged production is sold. Oil and gas sales included realized hedging gains of $4.2 million in 2007 compared to losses of $93.2 million in 2006 and losses of $153.7 million in 2005. Unrealized effective gains and losses on derivatives that qualify for hedge accounting are recorded at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX, on our consolidated balance sheet as accumulated other comprehensive income, a component of stockholders equity.

At December 31, 2007, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price
Natural Gas			
2008	Swaps	155,000 Mmbtu/day	$8.97
2008	Collars	70,000 Mmbtu/day	$8.01 $10.83
2009	Swaps	40,000 Mmbtu/day	$8.24
2009	Collars	80,000 Mmbtu/day	$8.12 $8.76
Crude Oil			
2008	Collars	9,000 bbl/day	$59.34 $75.48
2009	Collars	8,000 bbl/day	$64.01 $76.00

Some of our derivatives do not qualify for hedge accounting but are effective as economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Under this method the contracts are carried at their fair value on our consolidated balance sheet under the captions Unrealized derivative gains and Unrealized derivative losses. We recognize all unrealized and realized gains and losses related to these contracts in our consolidated statement of operations in the caption Derivative fair value income (loss).

As of the fourth quarter of 2005, certain of our gas derivatives no longer qualified for hedge accounting and are marked to market. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, a portion of derivatives which were designated to our Gulf Coast production was marked to market. In the fourth quarter of 2007, we began marking a portion of our oil hedges designated as Permian production to market due to the anticipated sale of a portion of our Permian properties. Derivatives that no longer qualify for hedge accounting are accounted for using the mark-to-market accounting method described above. As of December 31, 2007, hedges on 64.0 Bcfe no longer qualify or are not designated for hedge accounting.

During the third and fourth quarter of 2007, in addition to the swaps and collars above, we entered into basis swap agreements which do not qualify as hedges for hedge accounting purposes and are marked to market. The price we receive for our production can be less than NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax gain of $145,000 at December 31, 2007.

Interest Rates

At December 31, 2007, we had $1.2 billion of debt outstanding. Of this amount, $850.0 million bears interest at fixed rates averaging 7.3%. Bank debt totaling $303.5 million bears interest at floating rates, which averaged 6.2% at year-end 2007. The 30-day LIBOR rate on December 31, 2007 was 4.6%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2007 would cost us approximately $3.0 million in additional annual interest.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements to enhance our liquidity or capital resource position, or for any other purpose.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and accelerated through 2007, commodity prices for oil and gas increased significantly. The higher prices have led to increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs but also on our capital costs. We expect these costs to remain high for 2008.

The following table indicates the average oil and gas prices received over the last five years and quarterly for 2007, 2006 and 2005. Average price calculations exclude all derivative settlements whether or not they qualify for hedge accounting. Oil is converted to natural gas equivalent at the rate of one barrel equals six mcfe.

	Average Sales Prices (Wellhead)			Average NYMEX Prices [(a)]	
	Oil (Per bbl)	Natural Gas (Per mcf)	Equivalent Mcf (Per mcfe)	Oil (Per bbl)	Natural Gas (Per mcf)
Annual					
2007	$ 67.47	$ 6.54	$ 7.37	$ 72.34	$ 6.92
2006	62.36	6.59	7.25	66.22	7.26
2005	53.30	8.00	7.99	56.56	8.55
2004	39.20	5.80	5.79	41.41	6.09
2003	28.23	5.03	4.85	31.04	5.44
Quarterly					
2007					
First	$ 56.01	$ 6.41	$ 6.88	$ 58.27	$ 6.96
Second	62.20	6.95	7.57	65.03	7.56
Third	70.51	5.97	7.01	75.38	6.13
Fourth	82.12	6.80	7.94	90.68	7.03
2006					
First	$ 59.74	$ 8.33	$ 8.41	$ 63.48	$ 9.07
Second	65.36	6.28	7.17	70.70	6.82
Third	64.53	6.12	7.00	70.48	6.53
Fourth	59.80	5.91	6.58	60.21	6.62
2005					
First	$ 47.01	$ 5.98	$ 6.25	$ 49.84	$ 6.32
Second	48.72	6.41	6.65	53.17	6.80
Third	59.94	7.88	8.16	63.19	8.25
Fourth	56.38	11.30	10.54	60.02	12.85

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

Management s Discussion of Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ.

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

Oil and Gas Properties

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

The following table sets forth a summary of the percent of reserves which were reviewed by independent petroleum consultants for each of the years ended 2007, 2006 and 2005.

	Audited [a]	
2007	2006	2005
86%	87%	84%

[a] Audited reserves are those reserves estimated by our employees and reviewed by an independent petroleum consultant.

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

We adhere to the Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider a combination of time, geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $271.4 million in 2007 compared to $226.2 million in 2006 and $28.5 million in 2005.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. Estimated reserves are used as the basis for calculating the expected future cash flows from a property, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to oil and gas producing activities and reserve quantities in Note 19 to our consolidated financial statements. Changes in the estimated reserves are considered in estimates for accounting purposes and are reflected on a prospective basis.

We monitor our long-lived assets recorded in property, plant and equipment in our consolidated balance sheet to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustment to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts, environmental regulations or tax laws. All of these factors must be considered when testing a property s carrying value for impairment. We cannot predict whether impairment charges may be required in the future.

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

Oil and Gas Derivatives

We enter into derivative contracts to mitigate our exposure to commodity price risk associated with future oil and natural gas production. These contracts have historically consisted of options, in the form of collars, and fixed price swaps. Under SFAS No. 133, every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized currently in earnings. If the derivative qualifies for cash flow hedge accounting, the change in fair value of the derivative is recognized in accumulated other comprehensive income (equity) to the extent that the hedge is effective and in the income statement to the extent it is ineffective.

Some of our derivatives do not qualify for hedge accounting but are effective as economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Unrealized derivative assets and Unrealized derivative liabilities. We recognize all unrealized and realized gains and losses related to these contracts on our consolidated statement of operations under the caption Derivative fair value income (loss).

As of the fourth quarter of 2005, certain of our gas derivatives no longer qualified for hedge accounting due to the effect of volatility of gas prices on the correlation between realized prices and hedge reference prices. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, the portion of derivatives which were designated to our Gulf Coast production no longer qualified for hedge accounting resulting in derivative fair value income of $209,000. In the fourth quarter of 2007, we began marking a portion of our oil hedges designated as Permian production to market due to the anticipated sale of a portion of our Permian properties resulting in derivative fair value loss of $14.7 million. These derivatives that no longer qualify for hedge accounting under SFAS No. 133 are accounted for using the mark-to-market accounting method described above.

During the third and fourth quarter of 2007, we entered into basis swap agreements which do not qualify as hedges for hedge accounting and are also marked to market. The price we receive for our gas production can be less than the NYMEX price because of adjustments for delivery location, or basis, relative quality and other factors; therefore, we have entered into basis swap agreement that effectively fix our basis adjustments.

While there is a risk that the financial benefit of rising oil and gas prices may not be captured, we believe the benefits of stable and predictable cash flow are more important. Among these benefits are a more efficient utilization of existing personnel and planning for future staff additions, the flexibility to enter into long-term projects requiring substantial committed capital, smoother and more efficient execution of our ongoing development drilling and production enhancement programs, more consistent returns on invested capital, and better access to bank and other credit markets.

Asset Retirement Obligations

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

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation, (ARO), a corresponding adjustment is made to the oil and gas property balance. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in our consolidated statement of operations. Due to the sale of our Gulf of Mexico assets in the first quarter of 2007, our ARO liability decreased $20.0 million.

Deferred Taxes

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

In determining deferred tax liabilities, accounting rules require OCI to be considered, even though such income or loss has not yet been earned. At year-end 2006, deferred tax liabilities exceeded deferred tax assets by $468.6 million, with $21.3 million of deferred tax liabilities related to unrealized deferred hedging gains included in OCI. At year-end 2007, deferred tax liabilities exceeded deferred tax assets by $563.9 million, with $16.3 million of deferred tax assets related to unrealized hedging losses included in OCI.

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

Contingent Liabilities

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

Revenue Recognition

Oil, gas and natural gas liquids are recognized when the products are sold and delivery to the purchaser has occurred. We use the sales method the account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of gas produced.

Accounting Standards Not Yet Adopted

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. This statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measure at fair value. It requires that unrealized gains and losses on items for which the fair value option has been elected be recorded in net income. The statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. For us, SFAS No. 159 will be effective January 1, 2008, and retrospective application is not permitted. Should we elect to apply the fair value option to any eligible items that exist at January 1, 2008, the effect of the first remeasurement to fair value would be reported as a cumulative effect adjustment to the opening balance of retained earnings. We will adopt SFAS No. 159 as of January 1, 2008 and the impact of the adoption will result in a reclassification of a $2.0 million pre-tax loss related to our investment securities from accumulated other comprehensive loss to retained earnings.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurement. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. For us, SFAS No. 157 will be effective January 1, 2008. We have not yet determined whether SFAS No. 157 will have a material impact on our financial condition, results of operations or cash flow. However, we believe we will be required to provide additional disclosures as part of future financial statements, beginning with the first quarter of 2008.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) replaces SFAS No. 141. The statement retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in the purchase accounting. It changes the recognition of

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assets acquired and liabilities assumed arising from contingencies, requires the capitalization of in-process research and development at fair value, and requires the expensing of acquisition-related costs as incurred. The statement will apply prospectively to business combinations occurring in our fiscal year beginning January 1, 2009. We are currently evaluating provisions of this statement.

ITEM 7A. QUANTITIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Market Risk

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

Commodity Price Risk

We periodically enter into derivative arrangements with respect to our oil and gas production. These arrangements are intended to reduce the impact of oil and gas price fluctuations. Certain of our derivatives are swaps where we receive a fixed price for our production and pay market prices to the counterparty. Our derivatives program also includes collars which assume a minimum floor price and a predetermined ceiling price. Historically, we applied hedge accounting to derivatives utilized to manage price risk associated with our oil and gas production. Accordingly, we recorded change in the fair value of our swap and collar contracts, including changes associated with time value, under the caption, Accumulated other comprehensive income (loss) and into oil and gas sales when the forecasted sale of production occurs. Any hedge ineffectiveness associated with contracts qualifying for and designated as a cash flow hedge is reported currently each period under the caption Derivative fair value income (loss) in our consolidated statement of operations. Some of our derivatives do not qualify for hedge accounting but are effective as economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Unrealized derivative gains and Unrealized derivative losses. We recognize all unrealized and realized gains and losses related to these contracts in our consolidated statement of operations under the caption Derivative fair value income (loss). Generally, derivative losses occur when market prices increase, which are offset by gains on the underlying physical commodity transaction. Conversely, derivative gains occur when market prices decrease, which are offset by losses on the underlying commodity transaction. We do not enter into derivative instruments for trading purposes.

As of December 31, 2007, we had oil and gas swaps in place covering 71.3 Bcf of gas. We also had collars covering 54.8 Bcf of gas and 6.2 million barrels of oil. These contracts expire monthly through December 2009. The fair value, represented by the estimated amount that would be realized upon immediate liquidation as of December 31, 2007, approximated a net unrealized pre-tax loss of $22.3 million.

At December 31, 2007, the following commodity derivative contracts were outstanding:

Period	Contract Type	Volume Hedged	Average Hedge Price	Fair Market Value (in thousands)
Natural Gas				
2008	Swaps	155,000 Mmbtu/day	$ 8.97	$ 64,982
2008	Collars	55,000 Mmbtu/day	$ 8.01 - $10.83	$ 19,288
2009	Swaps		$ 8.24	$ (3,812)

		40,000 Mmbtu/day		
2009	Collars	80,000 Mmbtu/day	$ 8.12 - $8.76	$ (3,070)
Crude Oil				
2008	Collars	9,000 bbl/day	$ 59.34 - $75.48	$ (59,624)
2009	Collars	8,000 bbl/day	$ 64.01 - $76.00	$ (40,085)

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Other Commodity Risk

We are impacted by basis risk, caused by factors that affect the relationship between commodity futures prices reflected in derivative commodity instruments and the cash market price of the underlying commodity. Natural gas transaction prices are frequently based on industry reference prices that may vary from prices experienced in local markets. If commodity price changes in one region are not reflected in other regions, derivative commodity instruments may no longer provide the expected hedge, resulting in increased basis risk. In addition to the collars and swaps above, during the third and fourth quarter of 2007, we entered into basis swap agreements which do not qualify for hedge accounting purpose and are marked to market. The price we receive for our gas production can be less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix the basis adjustments. The fair value of the basis swaps was a net realized pre-tax gain of $145,000 at December 31, 2007.

In 2007, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $85.4 million. If oil and gas futures prices at December 31, 2007 had declined by 10%, the unrealized hedging gain at that date would have increased $137.9 million.

Interest Rate Risk

At December 31, 2007, we had $1.2 billion of debt outstanding. Of this amount, $850.0 million bears interest at a fixed rate averaging 7.3%. Bank debt totaling $303.5 million bears interest at floating rates, which averaged 6.2% on that date. On December 31, 2007, the 30-day LIBOR rate was 4.6%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2007 would cost us approximately $3.0 million in additional annual interest rates.

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

	Carrying Value	Fair Value
Fixed rate debt:		
Senior Subordinated Notes due 2013	$197,602	$204,000
(The interest rate is fixed at a rate of 7.375%)		
Senior Subordinated Notes due 2015	150,000	147,750
(The interest rate is fixed at a rate of 6.375%)		
Senior Subordinated Notes due 2016	249,556	254,375
(The interest rate is fixed at a rate of 7.5%)		
Senior Subordinated Notes due 2017	250,000	251,250
(The interest rate is fixed at a rate of 7.5%)		

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2007.

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Management s Annual Report on Internal Control over Financial Reporting and Attestation Report of Registered Public Accounting Firm. Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management s assessment of the design and effectiveness of its internal controls as part of this Annual Report on Form 10-K for the fiscal year ended December 31, 2007. Ernst & Young LLP, our registered public accountants, also attested to, and reported on, management s assessment of the effectiveness of internal control over financial reporting. Management s report and the independent public accounting firms attestation report are included in our 2007 Financial Statements in Item 15 under the captions Management s Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, of our internal control over financial reporting to determine whether any changes occurred during the fourth quarter of 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on that evaluation, there were no changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The officers and directors are listed below with a description of their experience and certain other information. Each director was elected for a one-year term at the 2007 annual stockholders meeting. Officers are appointed by our board of directors.

	Age	Office Held Since	Position
Charles L.Blackburn	80	2003	Director, Chairman of the Board
Anthony V. Dub	58	1995	Director
V. Richard Eales	71	2001	Director
Allen Finkelson	61	1994	Director
Jonathan S. Linker	59	2002	Director
Kevin S. McCarthy	48	2005	Director
John H. Pinkerton	53	1990	Director, President, Chief Executive Officer
Jeffrey L. Ventura	50	2003	Director, Executive Vice President Chief Operating Officer
Alan W. Farquharson	50	2007	Senior Vice President Reservoir Engineering
Steven L. Grose	59	2005	Senior Vice President Appalachia
Roger S. Manny	50	2003	Senior Vice President and Chief Financial Officer
Chad L. Stephens	52	1990	Senior Vice President Corporate Development
Rodney L. Waller	58	1999	Senior Vice President, Chief Compliance Officer and Corporate Secretary
Mark D. Whitley	56	2005	Senior Vice President Permian Business Unit and Engineering Technology

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

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

V. Richard Eales became a director in 2001. Mr. Eales has over 35 years of experience in the energy, high technology and financial industries. He is currently retired, having been a financial consultant serving energy and information technology businesses from 1999 through 2002. Mr. Eales was employed by Union Pacific Resources Group Inc. from 1991 to 1999 serving as Executive Vice President from 1995 through 1999. Prior to 1991, Mr. Eales served in various financial capacities with Butcher & Singer and Janney Montgomery Scott, investment banking firms, as CFO of Novell, Inc., a technology company, and in the treasury department of Mobil Oil Corporation.

Mr. Eales received his Bachelor of Chemical Engineering from Cornell University and his Masters in Business Administration from Stanford University.

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

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

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

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

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

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

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

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

Chad L. Stephens, Senior Vice President Corporate Development, joined Range in 1990. Prior to 2002, Mr. Stephens held the position of Senior Vice President Southwest. Previously, Mr. Stephens was with Duer Wagner

& Co., an independent oil and gas producer for approximately two years. Before that, Mr. Stephens was an independent oil operator in Midland, Texas for four years. From 1979 to 1984, Mr. Stephens was with Cities Service Company and HNG Oil and Gas Company. Mr. Stephens received a Bachelor of Arts in Finance and Land Management from the University of Texas.

Rodney L. Waller, Senior Vice President, Chief Compliance Officer and Corporate Secretary, joined Range in 1999. Since joining Range, Mr. Waller has held the position of Senior Vice President and Corporate Secretary. In 2005, Mr. Waller was appointed Chief Compliance Officer. Previously, Mr. Waller was Senior Vice President of SOCO, now part of Devon Energy Corporation. Before joining SOCO, Mr. Waller was with Arthur Andersen. Mr. Waller is a certified public accountant and petroleum land man. Mr. Waller served as a director of Range from 1988 to 1994. Mr. Waller received a Bachelor of Arts degree in Accounting from Harding University.

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

Section 16(a) Beneficial Ownership Reporting Compliance

See the material appearing under the heading Section 16(a) Beneficial Ownership Reporting Compliance in the Range Proxy Statement for the 2008 Annual Meeting of stockholders which is incorporated herein by reference. Section 16(a) of the Exchange Act requires our directors, officers (including a person performing a principal policy-making function) and persons who own more than 10% of a registered class of our equity securities to file with the Commission initial reports of ownership and reports of changes in ownership of our common stock and other equity securities of ours. Directors, officers and 10% holders are required by Commission regulations to send us copies of all of the Section 16(a) reports they file. Based solely upon a review of the copies of the forms sent to us and the representations made by the reporting persons to us, we believe that, other than as described below, during the fiscal year ended December 31, 2007, our directors, officers and 10% holders complied with all filing requirements under Section 16(a) of the Exchange Act. Each of those listed below had two delinquent Form 4 filings a filing on February 26, 2007 for a transaction that occurred on February 21, 2007 and a filing on January 3, 2008 for a transaction that occurred on December 18, 2007:

Mr. Steven Grose	Mr. Jeffrey Ventura
Mr. Roger Manny	Mr. Rodney Waller
Mr. John Pinkerton	Mr. Mark Whitley
Mr. Chad Stephens	

In addition, Mr. Alan Farquharson had a delinquent Form-4 filing on January 3, 2008 for a transaction that occurred on December 18, 2007.

Code of Ethics

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

Identifying and Evaluating Nominees for Directors

See the material under the heading Consideration of Director Nominees in the Range Proxy Statement for the 2008 Annual Meeting of stockholders which is incorporated herein by reference.

Audit Committee

See the material under the heading Audit Committee in the Range Proxy Statement for the 2008 Annual Meeting of stockholders which is incorporated herein by reference.

NYSE 303A Certification

The Chief Executive Officer of Range Resources Corporation made an unqualified certification to the NYSE with respect to the Company s compliance with the NYSE Corporate Governance listing standards on June 8, 2007.

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ITEM 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to such information as set forth in our definitive Proxy Statement for the 2008 Annual Meeting of stockholders.

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

Information required by this item is incorporated by reference to such information as set forth in our definitive proxy statement for the 2008 Annual Meeting of stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to such information as set forth in our definitive proxy statement for the 2008 Annual Meeting of stockholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this item is incorporated by reference to such information as set forth in our definitive proxy statement for the 2008 Annual Meeting of stockholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of the report

1. Financial Statements:

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

3. Exhibits:

(a) See Index of Exhibits on page F-37 for a description of the exhibits filed as a part of this report.

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GLOSSARY OF CERTAIN DEFINED TERMS

The terms defined in this glossary are used in this report.
bbl. One stock tank barrel, or 42 U.S. gallons liquid volumes, used herein in reference to crude oil or other liquid hydrocarbons.
bcf. One billion cubic feet of gas.
bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGL, which reflects relative energy content.
development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
dry hole. A well found to be incapable of producing oil or natural gas in sufficient economic quantities.
exploratory well. A well drilled to find oil or gas in an unproved area, to find a new reservoir in an existing field or to extend a known reservoir.
gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.
infill well. A well drilled between known producing wells to better exploit the reservoir.
LIBOR. London Interbank Offer Rate, the rate of interest at which banks offer to lend to one another in the wholesale money markets in the City of London. This rate is a yardstick for lenders involved in many debt transactions.
Mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.
mcf. One thousand cubic feet of gas.
mcf per day. One thousand cubic feet of gas per day.
mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 mcf for each barrel of oil or NGL, which reflects relative energy content.
Mmbbl. One million barrels of crude oil or other liquid hydrocarbons.
Mmbtu. One million British thermal units. A British thermal unit is the heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.
Mmcf. One million cubic feet of gas.
Mmcfe. One million cubic feet of gas equivalents.
NGLs. Natural gas liquids.
net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.
present value (PV). The present value of future net cash flows, using a 10% discount rate, from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions). The after tax present value is the Standardized Measure.
productive well. A well that is producing oil or gas or that is capable of production.
proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

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proved developed reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economics and operating conditions.

proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

recompletion. The completion for production an existing well bore in another formation from that in which the well has been previously completed.

reserve life index. Proved reserves at a point in time divided by the then production rate (annual or quarterly).

royalty acreage. Acreage represented by a fee mineral or royalty interest which entitles the owner to receive free and clear of all production costs a specified portion of the oil and gas produced or a specified portion of the value of such production.

royalty interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens, and to all costs of exploration, development and operations, and all risks in connection therewith.

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SIGNATURES

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

Dated: February 26, 2008

RANGE RESOURCES CORPORATION

By: /s/ John H. Pinkerton
John H. Pinkerton
President and Chief Executive Officer

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

/s/ Charles L. Blackburn	Chairman of the Board	February 26, 2008
Charles L. Blackburn		
/s/ John H. Pinkerton	President, Chief Executive Officer and Director	February 26, 2008
John H. Pinkerton		
/s/ Jeffrey L. Ventura	Executive Vice President and Director	February 26, 2008
Jeffrey L. Ventura		
/s/ Roger S. Manny	Chief Financial and Accounting Officer	February 26, 2008
Roger S. Manny		
/s/ Anthony V. Dub	Director	February 26, 2008
Anthony V. Dub		
/s/ V. Richard Eales	Director	February 26, 2008
V. Richard Eales		
/s/ Allen Finkelson	Director	February 26, 2008
Allen Finkelson		
/s/ Jonathan S. Linker	Director	February 26, 2008
Jonathan S. Linker		
/s/ Kevin S. McCarthy	Director	February 26, 2008

Kevin S. McCarthy

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RANGE RESOURCES CORPORATION
INDEX TO FINANCIAL STATEMENTS

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to management and board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control - Integrated Framework.* Based on our assessment, we believe that, as of December 31, 2007, our internal control over financial reporting is effective based on those criteria.

By: /s/ John H. Pinkerton	By: /s/ Roger S. Manny
John H. Pinkerton *President and Chief Executive Officer*	Roger S. Manny *Senior Vice President and Chief Financial Officer*

Fort Worth, Texas
February 25, 2008

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

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

We have audited Range Resources Corporation s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Range Resources Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Range Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Range Resources Corporation as of December 31, 2007 and 2006 and the related consolidated statements of operations, stockholders equity, comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2007 and our report dated February 25, 2008 expressed an unqualified opinion thereon.

Ernst & Young LLP
Fort Worth, Texas
February 25, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders equity, comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Range Resources Corporation at December 31, 2007 and 2006, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, in 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), Share-Based Payment.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Range Resources Corporation s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2008 expressed an unqualified opinion thereon.

Ernst & Young LLP
Fort Worth, Texas
February 25, 2008

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

	December 31, 2007	December 31, 2006
Assets		
Current assets:		
Cash and equivalents	$ 4,018	$ 2,382
Accounts receivable, less allowance for doubtful accounts of $583 and $746	166,484	125,421
Assets held for sale		79,304
Assets of discontinued operation		78,161
Unrealized derivative gain	53,018	93,588
Deferred tax asset	26,907	
Inventory and other	11,387	10,069
Total current assets	261,814	388,925
Unrealized derivative gain	1,082	61,068
Equity method investments	113,722	13,618
Oil and gas properties, successful efforts method	4,443,577	3,359,093
Accumulated depletion and depreciation	(939,769)	(751,005)
	3,503,808	2,608,088
Transportation and field assets	104,802	80,066
Accumulated depreciation and amortization	(43,676)	(32,923)
	61,126	47,143
Other assets	74,956	68,832
Total assets	$ 4,016,508	$ 3,187,674
Liabilities		
Current liabilities:		
Accounts payable	$ 212,514	$ 171,914
Asset retirement obligations	1,903	3,853
Accrued liabilities	42,964	30,026
Liabilities of discontinued operation		28,333
Accrued interest	17,595	12,938
Unrealized derivative loss	30,457	4,621
Total current liabilities	305,433	251,685
Bank debt	303,500	452,000
Subordinated notes	847,158	596,782
Deferred tax, net	590,786	468,643

Unrealized derivative loss	45,819	266
Deferred compensation liability	120,223	90,094
Asset retirement obligations and other liabilities	75,567	72,043
Commitments and contingencies		
Stockholders Equity		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par, 250,000,000 shares authorized, 149,667,497 issued at December 31, 2007 and 138,931,565 issued at December 31, 2006	1,497	1,389
Common stock held in treasury 155,500 shares at December 31, 2007	(5,334)	
Additional paid-in capital	1,386,884	1,057,938
Retained earnings	371,800	160,313
Accumulated other comprehensive income (loss)	(26,825)	36,521
Total stockholders equity	1,728,022	1,256,161
Total liabilities and stockholders equity	$ 4,016,508	$ 3,187,674

See accompanying notes.

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

	Year Ended December 31, 2007	2006	2005
Revenues			
Oil and gas sales	$ 862,537	$ 599,139	$ 495,470
Transportation and gathering	2,290	2,422	2,306
Derivative fair value (loss) income	(7,767)	142,395	10,303
Other	5,031	856	1,024
Total revenue	862,091	744,812	509,103
Costs and expenses			
Direct operating	108,741	81,261	57,866
Production and ad valorem taxes	42,443	36,415	30,822
Exploration	43,345	44,088	29,529
General and administrative	68,428	49,886	33,444
Deferred compensation plan	28,332	6,873	29,474
Interest expense	77,737	55,849	37,619
Depletion, depreciation and amortization	227,328	154,739	114,364
Total costs and expenses	596,354	429,111	333,118
Income from continuing operations before income taxes	265,737	315,701	175,985
Income tax provision			
Current	320	1,912	1,071
Deferred	98,441	119,840	64,809
	98,761	121,752	65,880
Income from continuing operations	166,976	193,949	110,105
Discontinued operations, net of taxes	63,593	(35,247)	906
Net income	$ 230,569	$ 158,702	$ 111,011
Earnings per common share:			
Basic income from continuing operations	$ 1.16	$ 1.45	$ 0.89
discontinued operations	0.44	(0.26)	

net income	$ 1.60	$ 1.19	$ 0.89
Diluted income from continuing operations	$ 1.11	$ 1.39	$ 0.85
discontinued operations	0.43	(0.25)	0.01
net income	$ 1.54	$ 1.14	$ 0.86
Weighted average common shares outstanding:			
Basic	143,791	133,751	124,130
Diluted	149,911	138,711	129,126

See accompanying notes.

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

	Year Ended December 31,		
	2007	2006	2005
Operating activities:			
Net income	$ 230,569	$ 158,702	$ 111,011
Adjustments to reconcile net cash provided from operating activities:			
(Income) loss from discontinued operations	(63,593)	35,247	(906)
Income from equity method investments	(974)	(548)	
Deferred income tax expense	98,441	119,840	64,809
Depletion, depreciation and amortization	227,328	154,739	114,364
Exploration dry hole costs	15,149	15,089	6,559
Mark-to-market on oil and gas derivatives not designated as hedges	78,769	(86,491)	(10,868)
Unrealized derivative losses (gain)	820	(5,654)	3,505
Allowance for bad debts		80	675
Amortization of deferred financing costs and other	2,277	1,827	1,662
Deferred and stock-based compensation	54,152	27,455	37,391
Losses (gain) on sale of assets and other	2,212	940	(512)
Changes in working capital, net of amounts from business acquisitions:			
Accounts receivable	(50,570)	30,185	(64,333)
Inventory and other	(1,040)	(1,157)	(3,452)
Accounts payable	28,640	(5,049)	27,472
Accrued liabilities and other	9,922	(3,696)	1,219
Net cash provided from continuing operations	632,102	441,509	288,596
Net cash provided from discontinued operations	10,189	38,366	37,149
Net cash provided from operating activities	642,291	479,875	325,745
Investing activities:			
Additions to oil and gas properties	(782,398)	(487,245)	(266,396)
Additions to field service assets	(26,044)	(14,449)	(11,310)
Acquisitions, net of cash acquired	(336,453)	(360,149)	(153,600)
Investing activities of discontinued operations	(7,375)	(29,195)	(10,511)
Investment in equity method investment and other assets	(94,630)	(21,009)	
Proceeds from disposal of assets and discontinued operations	234,332	388	9,440
Purchases of marketable securities held by the deferred compensation plan	(48,018)		
Proceeds from the sales of marketable securities held by the deferred compensation plan	40,014		
Net cash used in investing activities	(1,020,572)	(911,659)	(432,377)

Financing activities:			
Borrowings on credit facilities	864,500	802,500	299,000
Repayments on credit facilities	(1,013,000)	(619,700)	(453,700)
Issuance of subordinated notes	250,000	249,500	150,000
Dividends paid common stock	(19,082)	(12,189)	(7,614)
preferred stock			(2,213)
Debt issuance costs	(3,686)	(6,960)	(4,119)
Issuance of common stock	296,229	16,265	114,470
Other debt repayments/financing	3,877		(16)
Proceeds from the sales of common stock held by the deferred compensation plan	6,505		
Purchases of common stock held by the deferred compensation plan and other treasury stock purchases	(5,426)		(2,808)
Net cash provided from financing activities	379,917	429,416	93,000
Net increase (decrease) in cash and equivalents	1,636	(2,368)	(13,632)
Cash and equivalents at beginning of year	2,382	4,750	18,382
Cash and equivalents at end of year	$ 4,018	$ 2,382	$ 4,750

See accompanying notes.

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

	Common stock Shares	Par value	Treasury common stock	Additional paid-in capital	Retained earnings (deficit)	Deferred compensation	Accumulated other comprehensive (loss) income	Total
Balance December 31, 2004	**121,829**	**$1,218**	**$**	**$ 699,277**	**$ (89,597)**	**$ (1,257)**	**$ (43,301)**	**$ 566,340**
Issuance of common stock	8,084	81		124,929		(3,378)		**121,632**
Stock-based compensation expense				9,461				**9,461**
Common dividends declared ($0.0599 per share)					(7,614)			**(7,614)**
Treasury stock purchases			(2,808)					**(2,808)**
Treasury stock issuances			2,727					**2,727**
Other comprehensive loss							(103,826)	**(103,826)**
Net income					111,011			**111,011**
Balance December 31, 2005	129,913	1,299	(81)	833,667	13,800	(4,635)	(147,127)	**696,923**
Issuance of common stock	9,018	90		203,280		4,635		**208,005**
Stock-based compensation expense				20,991				**20,991**

Common dividends declared ($0.09 per share)					(12,189)			**(12,189)**
Treasury stock issuances			81					**81**
Other comprehensive gain							183,648	**183,648**
Net income					158,702			**158,702**
Balance December 31, 2006	138,931	1,389		1,057,938	160,313		36,521	**1,256,161**
Issuance of common stock	10,736	108		312,427				**312,535**
Stock-based compensation expense				16,519				**16,519**
Common dividends declared ($0.13 per share)					(19,082)			**(19,082)**
Treasury stock purchases			(5,334)					**(5,334)**
Other comprehensive loss							(63,346)	**(63,346)**
Net income					230,569			**230,569**
Balance December 31, 2007	**149,667**	**$1,497**	**$(5,334)**	**$1,386,884**	**$371,800**	**$**	**$ (26,825)**	**$1,728,022**

See accompanying notes.

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

	Year Ended December 31,		
	2007	2006	2005
Net income	$ 230,569	$ 158,702	$ 111,011
Net deferred hedging (losses) gains, net of tax:			
Contract settlements reclassified to income	(3,231)	60,764	109,887
Change in unrealized deferred hedging gains (losses)	(54,954)	120,832	(215,026)
Change in unrealized (losses) gains on securities held by deferred compensation plan, net of taxes	(5,161)	2,052	1,313
Comprehensive income	$ 167,223	$ 342,350	$ 7,185

See accompanying notes.

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RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) SUMMARY OF ORGANIZATION AND NATURE OF BUSINESS

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

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

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

During the first quarter of 2007, we sold our interests in our Austin Chalk properties that we purchased as part of the Stroud acquisition. We also sold our Gulf of Mexico properties at the end of the first quarter of 2007. In accordance with Financial Accounting Standards Board (FASB), Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment of Disposal of Long-Lived Assets, we have reflected the results of operations of the above divestitures as discontinued operations, rather than a component of continuing operations. The Austin Chalk properties were classified as assets held for sale since their purchase in 2006. All periods presented include the reclassification of our Gulf of Mexico operations as discontinued operations. See also Note 4 for additional information regarding discontinued operations.

Use of Estimates

The preparation of financial statements in accordance with generally accepted accounting principles in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end, the reported amounts of revenues and expenses during the year and the reported amount of proved oil and gas reserves. Actual results could differ from the estimates and assumptions used.

Income per Common Share

Basic net income per share is calculated based on the weighted average number of common shares outstanding. Diluted net income per share assumes issuance of stock compensation awards, provided the effect is not antidilutive. All common stock shares and per share amounts in the accompanying financial statements have been adjusted for the three-for-two stock split effected on December 2, 2005.

Business Segment Information

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

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

Revenue Recognition and Gas Imbalances

Oil, gas and natural gas liquids revenues are recognized when the products are sold and delivery to the purchaser has occurred. Although receivables are concentrated in the oil and gas industry, we do not view this as unusual credit risk. We provide for an allowance for doubtful accounts for specific receivables judged unlikely to be collected based on the age of the receivable, our experience with the debtor, potential offsets to the amount owed and economic conditions. In certain instances, we require purchasers to post stand-by letters of credit. Many of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. We have allowances for doubtful accounts relating to exploration and production receivables of $583,400 at December 31, 2007 compared to $745,900 at December 31, 2006.

We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of the gas produced. A liability is recognized when the imbalance exceeds the estimate of remaining reserves. Gas imbalances at December 31, 2007 and December 31, 2006 were not significant. At December 31, 2007, we had recorded a net liability of $533,000 for those wells where it was determined that there were insufficient reserves to recover the imbalance situation.

Cash and Equivalents

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

Marketable Securities

Holdings of equity securities held in our deferred compensation plans qualify as available-for-sale or trading and are recorded at fair value. Investments in the deferred compensation plans are in mutual funds. As of December 31, 2007, there was an unrealized loss of $2.0 million (pre-tax) in accumulated other comprehensive loss related to these investments.

Inventories

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

Oil and Gas Properties

We follow the successful efforts method of accounting for oil and gas producing activities. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, delay rentals and costs of carrying and retaining unproved properties are expensed. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. The status of suspended well costs is monitored continuously and reviewed not less than quarterly. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Oil and NGLs are converted to gas equivalent basis or mcfe at the rate of one barrel equals 6 mcf. The depletion, depreciation and amortization (DD&A) rates were $1.95 per mcfe in 2007 compared to $1.62 per mcfe in 2006 and $1.41 per mcfe in 2005. Depletion is provided on the units of production method. Unproved properties had a net book value of $271.4 million at December 31, 2007 compared to $226.2 million at December 31, 2006 and $28.5 million at December 31, 2005. The increase in unproved properties from 2005 to 2006 is primarily related to our Stroud acquisition completed in 2006. Unproved properties are reviewed quarterly for impairment and impaired if conditions indicate we will not explore the acreage before expiration or the carrying value is above fair value.

Our long-lived assets are reviewed for impairment periodically for events or changes in circumstances that indicate that the carrying amount of an asset may not be recoverable. Long-lived assets are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated expected undiscounted future net cash flows. The expected future net cash flows are estimated based on our plans to produce and develop proved reserves. Expected future cash inflow from the sale of production of reserves is calculated based on estimated future prices and estimated operating costs. We estimate prices based upon market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates. When the carrying value exceeds the sum of future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value, (as determined by discounted future net cash flows) and the carrying value of the asset. In the fourth quarter of 2006, we lowered our salvage value estimates on our Appalachia wells which increased DD&A expense by $4.6 million.

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

Transportation and Field Assets

Our gas transportation and gathering systems are generally located in proximity to certain of our principal fields. Depreciation on these systems is provided on the straight-line method based on estimated useful lives of 10 to 15 years. We receive third-party income for providing certain transportation and field services which is recognized as earned. Depreciation on the associated assets is calculated on the straight-line method based on estimated useful lives ranging from five to seven years. Buildings are depreciated over 10 to 15 years. Depreciation expense was $10.9 million in 2007 compared to $7.5 million in 2006 and $6.4 million in 2005.

Other Assets

The expenses of issuing debt are capitalized and included in other assets on our consolidated balance sheet. These costs are amortized over the expected life of the related instruments. When a security is retired before maturity or modifications significantly change the cash flows, related unamortized costs are expensed. Other assets at December 31, 2007 include $15.3 million of unamortized debt issuance costs, $51.5 million of marketable securities held in our deferred compensation plans and $7.7 million of other investments.

Stock-based Compensation

The 2005 Equity Based Compensation Plan (the 2005 Plan) authorizes the Compensation Committee of the Board of Directors to grant stock options, stock appreciation rights, restricted stock awards, and phantom stock rights to employees. The Non-Employee Director Stock Plan (the Director Plan) allows grants to our non-employee directors of our Board of Directors. The 2005 Plan was approved by shareholders in May 2005 and replaces our 1999 stock option plan. No new grants will be made from the 1999 stock option plan. The number of shares that may be issued under the 2005 Plan is equal to (i) 5.6 million shares (15.0 million less the 2.2 million shares issued under the 1999 Stock Options Plan prior to May 18, 2005, the effective date of the 2005 Plan and less the 7.2 million shares issuable pursuant to awards under the 1999 Stock Option Plan outstanding as of the effective date of the 2005 Plan) plus (ii) the number of shares subject to 1999 Stock Option Plan awards outstanding at May 18, 2005, that subsequently lapse or terminate without the underlying shares being issued. The Director Plan was approved by stockholders in May 2004 and no more than 300,000 shares of common stock may be issued under the Plan.

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

The Compensation Committee grants restricted stock to certain employees and to non-employee directors of the Board of Directors as part of their compensation. Compensation expense is recognized over the balance of the vesting period, which is typically three years for employee grants. All restricted shares that are granted are placed in the deferred compensation plan. See additional information in Note 12.

Before January 1, 2006, we accounted for stock options granted under our stock-based compensation plans under the recognition and measurement provisions of APB Opinion No. 25, Accounting for Stock Issued to Employees and related Interpretations, as permitted by SFAS No. 123, Accounting for Stock-Based Compensation. For our stock options, no stock-based compensation expense was recognized in our statements of operations prior to January 1, 2006, as all stock options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS No. 123(R), Share-Based Payment, using the modified prospective transition method. Under this transition method, compensation cost for stock options and stock appreciation rights recognized in 2006 includes (a) compensation cost ($11.2 million) for all stock-based payments granted prior to, but not yet vested as of December 31, 2005, based on the remaining service period and the grant date fair value estimated in accordance with the original provisions of Statement No. 123 and (b) compensation cost ($3.7 million) for all stock-based payments granted after December 31, 2005, based on the service period (on a straight line basis) and the grant-date fair value estimated in accordance with SFAS No. 123(R). Pursuant to SFAS No. 123(R), results for prior periods have not been restated. In 2006, stock based compensation has been allocated to direct operating expense ($1.4 million), exploration expense ($2.5 million) and general and administrative expense ($10.7 million) to align SFAS No. 123(R) expense with the employees cash compensation. In 2007, stock-based compensation has been allocated to direct operating expense ($1.8 million), exploration expense ($2.3 million) and general and administrative expense ($10.8 million). We recognize stock-based compensation expense on a straight-line basis over the requisite service period for the entire award. The expense we recognize is net of estimated forfeitures. We estimate our forfeiture rate based on prior experience and adjust it as circumstances warrant.S.CONT

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We also began granting stock-settled SARs in July 2005 as part of our stock-based compensation plans to reduce the dilutive impact of our equity plans. Before January 1, 2006, we accounted for SARs grants under the recognition and measurement provisions of APB Opinion No. 25, which required expense to be recognized equal to the amount by which the quoted market value exceeded the original grant price on a mark-to-market basis. Therefore, we recognized $5.8 million of compensation cost in the last six months of 2005 related to SARs. To present stock-based compensation expense on a consistent basis, the $5.8 million of 2005 SARs related expense has been allocated to direct operating expense ($480,000), exploration expense ($1.2 million), general and administrative expense ($4.0 million) and a $117,000 reduction to transportation and gathering revenues. Beginning January 1, 2006, as required under the provisions of SFAS No. 123(R), those SARs granted prior to, but not yet vested as of December 31, 2005, are being expensed over the service period based on grant date fair value estimated in accordance with the original provisions of SFAS No. 123 and all SARs granted after to December 31, 2005 are being expensed over the service period (on a straight-line basis) based on grant-date fair value estimated in accordance with SFAS No. 123(R).

As a result of adopting SFAS No. 123(R) on January 1, 2006, our income from continuing operations before income taxes and net income for 2006 is $18.2 million and $11.5 million lower, respectively, than if we had continued to account for stock-based compensation under APB Opinion No. 25. The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provisions of SFAS No. 123(R) to options and SARs granted under our stock-based compensation plans in 2005. For the purposes of this pro forma disclosure, the value is estimated using a Black-Scholes-Merton option-pricing formula and expensed over the option s vesting periods (in thousands, except per share data).

	Year Ended December 31, 2005
Net income, as reported	$ 111,011
Add: Total stock-based employee compensation expense included in net income, net of tax	23,556
Deduct: Total stock-based employee compensation expense determined under fair value based method, net of tax	(29,235)
Pro forma net income	$ 105,332
Earnings per share:	
Basic as reported	$ 0.89
Basic pro forma	0.85
Diluted as reported	0.86
Diluted pro forma	0.82

As required, the pro forma disclosures above included options and SARs granted since January 1, 1995. For purposes of pro forma disclosures, the estimated fair value is amortized to expense over the vesting period. For options with graded vesting, expense is recognized on a straight-line basis over the vesting period. The fair value of each option grant on the date of grant for the disclosures is estimated by using the Black-Scholes-Merton option pricing model with the following weighted-average assumptions used for 2005: fair value of $8.48 per share; expected dividend per share of $0.08; expected historical volatility factors of 54%; risk-free interest rates of 4.1%, and an average expected life of 5 years.

Derivative Financial Instruments and Hedging

We account for our derivative activities under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS Nos. 137, 138 and 149. The statement, as amended, establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value. The statement requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. All of the derivative instruments that we use are to manage the price risk attributable to our expected oil and gas production. Cash flows from oil and gas derivative contract settlements are reflected in operating activities in our statement of cash flows.

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

Some of our derivatives do not qualify for hedge accounting but are effective as economic hedges of our commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Under this method, the contracts are carried at their fair value on our consolidated balance sheet under the captions Unrealized derivative gains and Unrealized derivative losses. We recognize all unrealized and realized gains and losses related to these contracts in our consolidated statement of operations under the caption Derivative fair value income (loss).

As of the fourth quarter of 2005, certain of our gas derivatives no longer qualified for hedge accounting due to the effect of volatility of gas prices on the correlation between realized prices and hedge reference prices. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, the portion of derivatives which were designated to our Gulf Coast production no longer qualified for hedge accounting resulting in derivative fair value income of $209,000. In the fourth quarter of 2007, we began marking a portion of our oil hedges designated as Permian Basin production to market due to the anticipated sale of a portion of our Permian properties resulting in derivative fair value loss of $14.7 million. See also Note 17. Derivatives that no longer qualify for hedge accounting under SFAS No. 133 are accounted for using the mark-to-market accounting method described above.

During the third and fourth quarter of 2007, we entered into basis swap agreements which do not qualify as hedges for hedge accounting and are also marked to market. The price we receive for our gas production can be less than the NYMEX price because of adjustments for delivery location, or basis, relative quality and other factors; therefore, we have entered into basis swap agreement that effectively fix our basis adjustments.

Asset Retirement Obligations

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

Deferred Taxes

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

Accumulated Other Comprehensive Income (Loss)

We follow the provisions of SFAS No. 130, Reporting Comprehensive Income which establishes standards for reporting comprehensive income. Comprehensive income includes net income as well as all changes in equity during the period, except those resulting from investments and distributions to owners. At December 31, 2007, we had a $41.1 million pre-tax loss in OCI relating to unrealized commodity hedges. We also had a pre-tax loss of $2.0 million relating to our marketable securities held in our deferred compensation plans.

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The components of accumulated other comprehensive income (loss) and related tax effects for three years ended December 31, 2007, were as follows (in thousands):

	Gross	Tax Effect	Net of Tax
Accumulated other comprehensive loss at December 31, 2004	$ (69,231)	$ 25,930	$ (43,301)
Contract settlements reclassified to income	174,041	(64,154)	109,887
Change in unrealized deferred hedging losses	(341,222)	126,196	(215,026)
Change in unrealized gains (losses) on securities held by deferred compensation plan	2,049	(736)	1,313
Accumulated other comprehensive loss at December 31, 2005	(234,363)	87,236	(147,127)
Contract settlements reclassified to income	96,450	(35,686)	60,764
Change in unrealized deferred hedging gains	192,183	(71,351)	120,832
Change in unrealized gains (losses) on securities held by deferred compensation plan	3,203	(1,151)	2,052
Accumulated other comprehensive income at December 31, 2006	57,473	(20,952)	36,521
Contract settlements reclassified to income	(5,129)	1,898	(3,231)
Change in unrealized deferred hedging gains	(87,228)	32,274	(54,954)
Change in unrealized gains (losses) on securities held by deferred compensation plan	(8,194)	3,033	(5,161)
Accumulated other comprehensive loss at December 31, 2007	$ (43,078)	$ 16,253	$ (26,825)

Reclassifications

Certain reclassifications of prior years data have been made to conform to our current year classification. This includes the presentation of our Gulf of Mexico operations as discontinued operations, the reclassification of gains of $49.9 million in 2006 and $2.9 million in 2005 related to settled derivatives that do not qualify for hedge accounting from oil and gas sales to derivative fair value income (loss) and the reclassification of gains of $6.0 million in 2006 and a loss of $3.5 million in 2005 related to hedge ineffectiveness from other revenue to derivative fair value income (loss). These reclassifications did not impact our net income, stockholders equity or cash flows. See also Note 12 for further discussion of reclassifications related to our deferred compensation plan.

Accounting Pronouncements Implemented

In July 2006, the FASB issued FASB Interpretation (FIN) 48, Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109. FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, transition and disclosure. We adopted FIN No. 48 effective January 1, 2007, and adoption did not have a significant effect on its consolidated results of operations, financial position or cash flows. See Note 5 for other disclosures required by FIN No. 48.

Accounting Pronouncements Not Yet Adopted

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. For Range, SFAS No. 157 will be effective January 1, 2008. We have not yet determined whether SFAS No. 157 will have a material impact on our financial condition, results of operations or cash flow. However, we believe we will be required to provide additional disclosures as part of future financial statements, beginning with the first quarter 2008.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. This statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. It requires that unrealized gains and losses on items for which the fair value option has been elected be recorded in net income. The statement also establishes presentation and disclosure requirements designed to facilitate comparison between entities that choose different measurement attributes for similar types of assets and liabilities. For us, SFAS No.

159 will be effective January 1, 2008, and retrospective application is not permitted. Should we elect to apply the fair value option to any eligible items that exist at January 1, 2008, the effect of the first remeasurement to fair value would be reported as a cumulative effect adjustment to the opening balance of retained earnings. We will adopt SFAS No. 159 as of January 1, 2008 and the impact of the adoption will result in a reclassification of a $2.0 million pre-tax loss related to our investment securities from accumulated other comprehensive loss to retained earnings.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) replaces SFAS No. 141. The statement retains the purchase method of accounting for acquisitions, but requires a number of changes, including changes in the way assets and liabilities are recognized in the purchase accounting. It changes the recognition of assets acquired and liabilities assumed arising from contingencies, requires the capitalization of in-process research and development at fair value, and requires the expensing of acquisition-related costs as incurred. The statement will apply prospectively to business combinations occurring in our fiscal year beginning January 1, 2009. We are currently evaluating the provisions of this statement.

(3) ACQUISITIONS AND DISPOSITIONS

Acquisitions

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

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

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

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

Purchase price:	
Cash paid (including transaction costs)	$ 171,529
6.5 million shares of common stock (at fair value of $27.26 per share)	177,641
Stock options assumed (652,000 options)	9,478
Debt retired	106,700
Total	$ 465,348

Allocation of purchase price:	
Working capital deficit	$ (13,557)
Other long-term assets	55
Oil and gas properties	487,345
Assets held for sale	140,000
Deferred income taxes	(147,062)
Asset retirement obligations	(1,433)
Total	$ 465,348

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Pro forma

The following unaudited pro forma data include the results of operations as if the Stroud acquisition had been consummated at the beginning of 2005. The pro forma information for 2005, which is based on the historical results of Stroud, includes two material non-recurring amounts recognized by Stroud not directly related to the transaction and not expected to reoccur. The year ended December 31, 2005 pro forma information includes an $18.4 million pre-tax stock compensation expense related to restricted and unrestricted shares issued to Stroud management and employees and a pre-tax $6.2 million loss on repurchase of mandatorily redeemable preferred units. The pro forma data is based on historical information and does not necessarily reflect the actual results that would have occurred nor are they necessarily indicative of future results of operations (in thousands, except per share data).

	Year Ended December 31,	
	2006	2005
Revenues	$779,487	$526,491
Income from continuing operations	$315,220	$132,039
Net income	$161,998	$ 95,086
Per share data:		
Income from continuing operations-basic	$ 1.41	$ 0.63
Income from continuing operations-diluted	$ 1.36	$ 0.60
Net income basic	$ 1.18	$ 0.73
Net income diluted	$ 1.14	$ 0.70

Dispositions

In February 2007, we sold the Stroud Austin Chalk properties for proceeds of $80.4 million and recorded a loss on the sale of $2.3 million. These properties were acquired in 2006 as part of our Stroud acquisition and were classified as assets held for sale on the acquisition date. In March 2007, we sold our Gulf of Mexico properties for proceeds of $155.0 million and recorded a gain on the sale of $95.1 million. The sale included properties within the waters of the Gulf of Mexico (either state or federal). We have reflected the results of operations of the above divestitures as discontinued operations rather than a component of continuing operations for 2007 and all prior years. See Note 4 for additional information.

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(4) DISCONTINUED OPERATIONS

As part of the Stroud acquisition (also see discussion in Note 3), we purchased Austin Chalk properties in Central Texas which were sold in February 2007 for proceeds of $80.4 million. We originally allocated $140.0 million to these properties as part of the purchase price allocation. However, after the acquisition, natural gas prices started to decline. As a result, during 2006 we recognized impairment expense of $74.9 million. In March 2007, we also sold our Gulf of Mexico properties for proceeds of $155.0 million. All prior year periods include the reclassification of our Gulf of Mexico operations to discontinued operations. Discontinued operations for the years ended December 31, 2007, 2006 and 2005 are summarized as follows (in thousands):

	2007	2006	2005
Revenues			
Oil and gas sales [a]	$ 15,187	$ 54,192	$ 26,698
Transportation and gathering	10	85	155
Other	310	(19)	(116)
Gain on disposition of assets	92,757		
Total revenues	108,264	54,258	26,737
Costs and expenses			
Direct operating	2,559	12,201	9,246
Production and ad valorem taxes	141	1,065	694
Exploration and other	215	2,400	1,075
Interest expense [b]	845	3,232	1,178
Depletion, depreciation and amortization	6,672	14,953	13,150
Impairment [c]		74,910	
Total costs and expenses	10,432	108,761	25,343
Income (loss) from discontinued operations before income taxes	97,832	(54,503)	1,394
Income tax expense (benefit)	34,239	(19,256)	488
Income (loss) from discontinued operations, net of taxes	$ 63,593	$ (35,247)	$ 906
Production			
Crude oil (bbls)	40,634	139,189	102,455
Natural gas (mcf)	1,990,277	7,927,557	5,394,784
Total (mcfe) [d]	2,234,081	8,762,691	6,009,514

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

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

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

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

(5) INCOME TAXES

Our income tax expense from continuing operations was $98.8 million for the year ended December 31, 2007 compared to $121.8 million in 2006 and $65.9 million in 2005. A reconciliation between the statutory federal income tax rate and our effective income tax rate is as follows:

	Year Ended December 31,		
	2007	2006	2005
Federal statutory tax rate	35%	35%	35%
State	3	4	2
Texas Margin tax credit	(1)		
Consolidated effective tax rate	37%	39%	37%
Income taxes (refunded) paid (in thousands)	$ (571)	$ 1,973	$ 615

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

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Current:			
U.S. federal	$ (129)	$ 150	$
U.S. state and local	449	1,762	1,071
	$ 320	$ 1,912	$ 1,071
Deferred:			
U.S. federal	$ 94,310	$ 110,296	$ 61,279
U.S. state and local	4,131	9,544	3,530
	$ 98,441	$ 119,840	$ 64,809

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

	December 31,	
	2007	2006
	(in thousands)	
Deferred tax assets:		
Current		
Current net unrealized loss in OCI	$ 5,195	$
Deferred compensation	3,981	
Current portion of SFAS No. 143 liability	704	
Other	2,967	
Current portion of net operating loss carryforward	14,060	
Subtotal	26,907	
Non-current		
Net operating loss carryforward	25,675	69,141
Net unrealized loss in OCI	11,060	
Deferred compensation	41,255	38,664
AMT credits and other credits	4,546	804
Non-current portion of SFAS No. 143 liability	27,302	20,775
Other	9,046	14,671
Valuation allowance	(3,101)	(3,101)
Subtotal	115,783	140,954
Deferred tax liabilities:		
Non-current		
Depreciation, depletion and investments	(697,491)	(547,899)

Net unrealized gain in OCI		(21,264)
Cumulative ineffectiveness SFAS No. 133	(6,812)	(35,788)
Other	(2,266)	(4,646)
Subtotal	(706,569)	(609,597)
Net deferred tax liability	$ (563,879)	$ (468,643)

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At December 31, 2007, deferred tax liabilities exceeded deferred tax assets by $563.9 million, with $16.3 million of deferred tax assets related to net deferred hedging losses included in OCI. A portion of our deferred tax assets relate to items which are capital assets, which upon disposition will result in capital losses. Due to the uncertainty related to the utilization of the capital loss, a valuation allowance was recognized in the amount of $3.1 million.

At December 31, 2007, we had regular net operating loss (NOL) carryforwards of $204.4 million and alternative minimum tax (AMT) NOL carryforwards of $149.7 million that expire between 2012 and 2027. Our deferred tax asset related to regular NOL carryforwards at December 31, 2007 was $39.7 million, net of the SFAS No. 123(R) reduction for unrealized benefits. Regular NOLs generally offset taxable income and to such extent, no income tax payments are required. We have $26.9 million of NOLs generated in years before 1998 which are subject to yearly limitations due to IRC Section 382. We do not believe the application of the Section 382 limitation hinders our ability to use such NOLs and therefore, no valuation allowance has been provided. At December 31, 2007, we have AMT credit carryforwards of $777,000 that are not subject to limitation or expiration.

We file consolidated tax returns in the United States federal jurisdiction and separate income tax returns in many state jurisdictions. We are subject to U.S. Federal income tax examinations for the years after 2002 and we are subject to various state tax examinations for years after 2001. Our continuing policy is to recognize interest related to income tax expense in interest expense and penalties in general and administrative expense. We do not have any accrued interest or penalties related to tax amounts as of December 31, 2007. Throughout 2007, our unrecognized tax benefits were not material.

(6) EARNINGS PER COMMON SHARE

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

	Year Ended December 31,		
	2007	2006	2005
Numerator:			
Income from continuing operations	$ 166,976	$ 193,949	$ 110,105
Income (loss) from discontinued operations	63,593	(35,247)	906
Net income	$ 230,569	$ 158,702	$ 111,011
Denominator:			
Weighted average shares outstanding	145,869	135,016	126,339
Stock held in deferred compensation plan and treasury shares	(2,078)	(1,265)	(2,209)
Weighted average shares, basic	143,791	133,751	124,130
Effect of dilutive securities:			
Weighted average shares outstanding	145,869	135,016	126,339
Employee stock options, SARs and stock held in deferred compensation plan	4,100	3,696	2,863
Treasury shares	(58)	(1)	(76)
Dilutive potential common shares for diluted earnings per share	149,911	138,711	129,126
Basic income from continuing operations	$ 1.16	$ 1.45	$ 0.89
discontinued operations	0.44	(0.26)	

net income	$	$1.60	$	1.19	$	0.89
Diluted income from continuing operations	$	1.11	$	1.39	$	0.85
discontinued operations		0.43		(0.25)		0.01
net income	$	1.54	$	1.14	$	0.86

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Stock appreciation rights for 345,000 shares were outstanding but not included in the computations of diluted net income per share for the year ended December 31, 2007 because the exercise price of the SARs was greater than the average price of the common shares and would be anti-dilutive to the computations. Stock appreciation rights for 88,500 shares were outstanding but not included in the computations of diluted net income per share for the year ended December 31, 2006 because the exercise price of the SARs was greater than the average price of the common shares and would be anti-dilutive to the computations.

(7) SUSPENDED EXPLORATORY WELL COSTS

The following table reflects the changes in capitalized exploratory well costs for the year ended December 31, 2007, 2006 and 2005 (in thousands):

	2007	2006	2005
Balance at beginning of period	$ 9,984	$ 25,340	$ 7,332
Additions to capitalized exploratory well costs pending the determination of proved reserves	14,428	4,695	26,915
Divested wells	(1,325)		
Reclassifications to wells, facilities and equipment based on determination of proved reserves		(16,710)	(8,614)
Capitalized exploratory well costs charged to expense	(8,034)	(3,341)	(293)
Balance at end of period	15,053	9,984	25,340
Less exploratory well costs that have been capitalized for a period of one year or less	(12,067)	(4,792)	(21,589)
Capitalized exploratory well costs that have been capitalized for a period greater than one year	$ 2,986	$ 5,192	$ 3,751
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	2	3	3

As of December 31, 2007, of the $3.0 million of capitalized exploratory well costs that have been capitalized for more than one year, all of the wells have additional exploratory wells in the same prospect area drilling or firmly planned. One of the wells is not operated by us. Of the $15.1 million of capitalized exploratory well costs at December 31, 2007, $12.1 million was incurred in 2007 and $3.0 million in 2006.

(8) INDEBTEDNESS

We had the following debt outstanding as of the dates shown below (bank debt interest rate at December 31, 2007 is shown parenthetically). No interest was capitalized during 2007, 2006, and 2005 (in thousands):

	December 31, 2007	December 31, 2006
Bank debt (6.2%)	$ 303,500	$ 452,000
Senior subordinated notes:		
7.375% senior subordinated notes due 2013, net of $2.4 million and $2.7 million discount, respectively	197,602	197,262
6.375% senior subordinated notes due 2015	150,000	150,000
7.5% senior subordinated notes due 2016, net of $444,000 and $480,000 discount	249,556	249,520
7.5% senior subordinated notes due 2017	250,000	
Total debt	$ 1,150,658	$ 1,048,782

Bank Debt

In October 2006, we entered into an amended and restated $900.0 million revolving bank credit facility, which we refer to as our bank debt or bank credit facility, which is secured by substantially all of our assets. The bank credit facility provides for an initial commitment equal to the lesser of the facility amount or the borrowing base. On December 31, 2007, the facility amount was $900.0 million and the borrowing base was $1.5 billion. The bank credit facility provides for a borrowing base subject to redeterminations semi-annually each April and October and pursuant to certain unscheduled redeterminations. The facility amount may be increased to the borrowing base amount with twenty-days notice. As of December 31, 2007, the outstanding balance under the bank credit facility was $303.5 million and there was $596.5 million of borrowing capacity available under the facility amount. The loan matures on October 25, 2012. Borrowing under the bank credit facility can either be base rate loans or LIBOR loans. On all base rate loans, the rate per annum is equal to the lesser of (i) the maximum rate (the weekly ceiling as defined in Section 303 of the Texas Finance Code or other applicable laws if greater) (the Maximum Rate) or, (ii) the sum of the higher of (1) the prime rate for such date, or (2) the sum of the federal funds effective rate for such date plus one-half of one percent (0.50%) per annum, plus a base rate margin of between 0.0% to 0.5% per annum depending on the total outstanding under the bank credit facility relative to the borrowing base. On all LIBOR loans, we pay a varying rate per annum equal to the lesser of (i) the Maximum Rate, or (ii) the sum of the quotient of (A) the LIBOR base rate, divided by (B) one minus the reserve requirement applicable to such interest period, plus a LIBOR margin of between 1.0% and 1.75% per annum depending on the total outstanding under the bank credit facility relative to the borrowing base. We may elect, from time-to-time, to convert all or any part of our LIBOR loans to base rate loans or to convert all or any of the base rate loans to LIBOR loans. The weighted average interest rate was 6.4% for the year ended December 31, 2007 compared to 6.4% for the year ended December 31, 2006. A commitment fee is paid on the undrawn balance based on an annual rate of 0.25% to 0.375%. At December 31, 2007, the commitment fee was 0.25% and the interest rate margin was 1.0%.

Senior Subordinated Notes

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

We may redeem the 7.375% Notes, in whole or in part, at any time on or after July 15, 2008, at redemption prices of 103.7% of the principal amount as of July 15, 2008, and declining to 100.0% on July 15, 2011 and thereafter. We may redeem the 6.375% Notes, in whole or in part, at any time on or after March 15, 2010, at redemption prices from 103.2% of the principal amount as of March 15, 2010 and declining to 100% on March 15, 2013 and thereafter. Before March 15, 2008, we may redeem up to 35% of the original aggregate principal amount of the 6.375% Notes at a redemption price of 106.4% of the principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings. We may redeem the 7.5% Notes due 2016, in whole or in part, at any time on or after May 15, 2011 at redemption prices from 103.75% of the principal amount as of May 15, 2011 and declining to 100% on May 15, 2014 and thereafter. Before May 15, 2009, we may redeem up to 35% of the original aggregate principal amount of the 7.5% Notes due 2016 at a redemption price of 107.5% of principal amount thereof plus accrued and unpaid interest if any, with the proceeds of certain equity offerings; provided that at least 65% of the original aggregate principal amount of our 7.5% Notes 2016 remains outstanding immediately after the occurrence of such redemption and provided that such redemption occurs within 60 days of the date of closing the equity sale. We may redeem the 7.5% Notes due 2017, in whole or in part, at any time on or after October 1, 2012 at redemption prices ranging from 103.75% of the principal amount as of October 1, 2012 and declining to 100% on October 1, 2015 and thereafter. Before October 1, 2010, we may redeem up to 35% of the original aggregate principal amount of the 7.5% Notes due 2017 at a redemption price of 107.5% of principal amount thereof plus accrued and unpaid interest, if any, with the proceeds of certain equity offerings provided that at least 65% of the original aggregate principal amount of our 7.5% Notes due 2017 remains outstanding immediately after the occurrence of such redemption and provided that such redemption occurs 60 days of the date of closing the equity sale.

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

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Guarantees

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

Debt Covenants

The debt agreements contain covenants relating to working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2007. Under the bank credit facility, common and preferred dividends are permitted, subject to the provisions of the restricted payment basket. The bank credit facility provides for a restricted payment basket of $20.0 million plus 50% of net income plus 66-2/3% of net cash proceeds from common stock issuances. Approximately $735.2 million was available under the bank credit facility s restricted payment basket on December 31, 2007. The terms of each of our subordinated notes limit restricted payments (including dividends) to the greater of $20.0 million or a formula based on earnings and equity issuances since the original issuances of the notes. The 7.5% Notes due 2016 allows for any cash proceeds received from the sale of oil and gas property purchased in the Stroud acquisition to be added to the restricted payment basket. At December 31, 2007, approximately $922.4 million was available under the restricted payment baskets for each of the 7.375% Notes, 6.375% Notes and the 7.5% Notes due 2017. There was $1.0 billion available under the restricted payment basket for the 7.5% Notes due 2016.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2007 (in thousands):

	Year Ended December 31,
2008	$
2009	
2010	
2011	
2012	303,500
2013	200,000
Thereafter	650,000
	$ 1,153,500

(9) ASSET RETIREMENT OBLIGATION

A reconciliation of our liability for plugging and abandonment costs for the years ended December 31, 2007 and 2006 is as follows (in thousands):

	2007	2006
Beginning of period	$ 95,588	$ 68,063
Liabilities incurred	3,118	4,006
Acquisitions continuing operations	3,301	790
Acquisitions discontinued operations		742
Liabilities settled	(2,782)	(3,057)
Disposition of wells	(20,066)	
Accretion expense continuing operations	5,960	4,824
Accretion expense discontinued operations	382	37
Change in estimate	(10,193)	20,183

End of period	75,308	95,588
Less current portion	(1,903)	(4,216)
Long-term asset retirement obligation	$ 73,405	$ 91,372

Accretion expense is recognized as a component of depreciation, depletion and amortization. December 31, 2006 includes $20.1 million related to discontinued operations ($363,000 current portion).

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(10) CAPITAL STOCK

We have authorized capital stock of 260.0 million shares which includes 250.0 million shares of common stock and 10.0 million shares of preferred stock. The following is a schedule of changes in the number of common shares issued since the beginning of 2006:

	Year Ended December 31,	
	2007	2006
Beginning balance	138,931,565	129,913,046
Public offerings	8,050,000	
Shares issued for Stroud acquisition		6,517,498
Shares issued in lieu of bonuses	29,483	20,686
Stock options/SARs exercised	2,220,627	1,956,164
Restricted stock grants	408,067	487,607
Shares contributed to 401(k) plan	27,755	36,564
Ending balance	149,667,497	138,931,565

In April 2007, we completed a public offering of 8.1 million shares of common stock at $36.28 per share. Total proceeds from the offering of $280.4 million funded our acquisition of additional interests in certain properties in Virginia and an associated equity interest in a gathering system.

Treasury Stock

During 2007, we bought in open market purchases, 155,500 shares at an average price of $34.30. The board of directors has approved up to $10.0 million of repurchases of common stock based on market conditions and opportunities. As of December 31, 2007, we have $4.7 million remaining authorization.

(11) FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

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

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

	December 31, 2007		December 31, 2006	
	Book Value	Fair Value	Book Value	Fair Value
Derivative assets:				
Commodity swaps and collars [a]	$ 54,100	$ 54,100	$ 154,656	$ 154,656
Derivative liabilities:				
Commodity swaps and collars [a]	(76,276)	(76,276)	(4,887)	(4,887)
Net derivative asset (liability)	$ (22,176)	$ (22,176)	$ 149,769	$ 149,769
Marketable securities [b]	$ 51,482	$ 51,482	$ 44,226	$ 44,226
Long-term debt [c]	$ 1,150,658	$ 1,158,033	$ 1,048,782	$ 1,058,069

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

(b) Marketable securities held in our deferred compensation plans which are marked to market.

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

Commodity Derivative Instruments

We use swap and collar derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future oil and gas production. While the use of these derivative instruments limit the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements. We do not hold or issue derivative financial instruments for speculative or trading purposes.

At December 31, 2007, we had open swap contracts covering 71.3 Bcf of gas at prices averaging $8.82 per mcf. We also had collars covering 54.8 Bcf of gas at weighted average floor and cap prices of $8.07 to $9.73 per mcf and 6.2 million barrels of oil at weighted average floor and cap prices of $61.54 to $75.72 per barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on a comparison of the contract price and a reference price, generally NYMEX, approximated a net unrealized pre-tax loss of $22.3 million at December 31, 2007. These contracts expire monthly through December 2009. The following table sets forth the derivative volumes by year as of December 31, 2007:

Period	Contract Type	Volume Hedged	Weighted Average Hedge Price		
Natural Gas					
2008	Swaps	155,000 Mmbtu/day	$		8.97
2008	Collars	70,000 Mmbtu/day	$	8.01	$10.83
2009	Swaps	40,000 Mmbtu/day	$		8.24
2009	Collars	80,000 Mmbtu/day	$	8.12	$8.76
Crude Oil					
2008	Collars	9,000 bbl/day	$	59.34	$75.48
2009	Collars	8,000 bbl/day	$	64.01	$76.00

Under SFAS No. 133, every derivative instrument is required to be recorded on the balance sheet as either an asset or a liability measured at its fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date, and/or the value confirmed by the counterparty. If the derivative does not qualify as a hedge or is not designated as a hedge, the change in fair value of the derivative is recognized in earnings. As of December 31, 2007, an unrealized pre-tax derivative loss of $41.1 million was recorded in accumulated other comprehensive income (loss). This loss is expected to be reclassified into earnings in 2008 ($7.2 million) and 2009 ($33.9 million). The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date.

For those derivative instruments that qualify for hedge accounting, settled transaction gains and losses are determined monthly and are included as increases or decreases to oil and gas sales in the period the hedged production is sold. Oil and gas sales include $4.2 million of gains in 2007 compared to losses of $93.2 million in 2006 and losses of $153.7 million in 2005. Any ineffectiveness associated with these hedges is reflected in derivative fair value income (loss) in our statement of operations. The year ended December 31, 2007 includes ineffective unrealized losses of $820,000 compared to gains of $6.0 million in 2006 and losses of $3.5 million in 2005. In the fourth quarter of 2005, certain of our gas hedges no longer qualified for hedge accounting due to the effect of gas price volatility on the correlation between realized prices and hedge reference prices and are marked to market. Also, as a result of the sale of our Gulf of Mexico assets in the first quarter of 2007, a portion of our derivatives which were designated to our Gulf Coast production was marked to market resulting in derivative fair value income of $209,000. In the fourth quarter of 2007, we began marking a portion of our oil hedges designated as Permian Basin production to market due to the anticipated sale of a portion of our Permian properties resulting in derivative fair value loss of $14.7 million. These derivatives have been retained to serve as economic hedges for our production even though we can no longer apply hedge accounting. We recognize all unrealized and realized gains and losses related to these contracts in our consolidated statement of operations under the caption Derivative fair value income (loss) (see table below).

During the third quarter of 2007, in addition to the swaps and collars above, we entered into basis swap agreements which do not qualify for hedge accounting and are marked to market. The price we receive for our gas production can be less than the NYMEX price because of adjustments for delivery location (basis), relative quality and other factors; therefore, we have entered into basis swap agreements that effectively fix our basis adjustments. The fair value of the basis swaps was a net unrealized pre-tax gain of $145,000 at December 31, 2007.

Derivative fair value income (loss)

The following table presents information about the components of derivative fair value income (loss) in the three-year period ended December 31, 2007 (in thousands):

	2007	2006	2005
Hedge ineffectiveness realized	$ 968	$	$
unrealized	(820)	5,965	(3,471)
Change in fair value of derivatives that do not qualify for hedge accounting	(78,769)	86,491	10,868
Realized gain on settlement-gas [a]	71,098	49,939	2,906
Realized loss on settlement-oil [a]	(244)		
Derivative fair value (loss) income	$ (7,767)	$ 142,395	$ 10,303

[a] These amounts represent the realized gains and losses on settled derivatives that do not qualify for hedge accounting, which before settlement are included in the category above called the

change in fair value of derivatives that do not qualify for hedge accounting.

The combined fair value of derivatives included in our consolidated balance sheets as of December 31, 2007 and 2006 is summarized below (in thousands). Derivative activities are conducted with major financial and commodities trading institutions which we believe are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. We have master netting agreements with our counterparties and the credit worthiness of our counterparties is subject to continuing review.

	December 31,	
	2007	2006
Derivative assets:		
Natural gas swaps	$ 54,577	$ 121,792
collars	4,916	36,973
basis swaps	1,082	
Crude oil collars	(6,475)	(4,109)
	$ 54,100	$ 154,656
Derivative liabilities:		
Natural gas swaps	$ 6,594	$ (248)
collars	11,302	2,337
basis swap	(937)	
Crude oil collars	(93,235)	(6,976)
	$ (76,276)	$ (4,887)

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(12) EMPLOYEE BENEFIT AND EQUITY PLANS

Stock and Option Plans

We have six equity-based stock plans, of which two are active. Under the active plans, incentive and non-qualified options, stock appreciation rights (SARs), restricted stock awards, phantom stock rights and annual cash incentive awards may be issued to directors and employees pursuant to decisions of the Compensation Committee which is made up of outside independent directors from the Board of Directors. All awards granted under these plans have been issued at the prevailing market price at the time of the grant. During 2007 and 2006, only SARs have been granted under the plans to limit the dilutive impact of our equity plans. Information with respect to stock option and SAR activities is summarized below:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2004	6,873,105	$ 5.09
Granted	3,141,937	16.96
Exercised	(1,105,549)	4.84
Expired/forfeited	(167,188)	9.08
Outstanding at December 31, 2005	8,742,305	9.31
Granted	1,658,160	24.36
Stock options assumed in Stroud acquisition	652,062	19.67
Exercised	(2,051,237)	9.22
Expired/forfeited	(149,164)	18.32
Outstanding at December 31, 2006	8,852,126	12.76
Granted	1,680,643	33.78
Exercised	(2,461,689)	9.45
Expired/forfeited	(298,755)	23.42
Outstanding at December 31, 2007	7,772,325	$ 17.95

The following table shows information with respect to outstanding stock options and SARs at December 31, 2007:

Range of Exercise Prices		Outstanding Shares	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Exercisable Shares	Weighted Average Exercise Price
$1.29	$9.99	2,378,044	2.31	$ 4.84	2,378,044	$ 4.84
10.00	19.99	2,322,548	2.40	16.29	1,307,911	15.95
20.00	29.99	1,477,365	3.24	24.44	453,157	24.47
30.00	39.99	1,576,468	4.23	33.80	44,550	37.95
40.00	44.75	17,900	4.80	42.56		

Total	7,772,325	2.91	$	17.95	4,183,662	$ 10.79

The weighted average fair value of a SAR to purchase one share of common stock during 2007 was $10.67. The fair value of each SAR granted during 2007 was estimated as of the date of grant using the Black-Scholes-Merton option pricing model based on the following assumptions: risk-free interest rate of 4.73%; dividend yield of 0.36%; expected volatility of 35.67%; and an expected life of 3.54 years. The volatility factors are based on a combination of both the historical volatilities of the stock and implied volatility of traded options on our common stock. The dividend yield is based on the current annual dividend at the time of grant. For SARs granted in 2007 and 2006, we used the simplified method prescribed by SEC Staff Accounting Bulletin No. 107 to estimate the expected term of the options, which is calculated based on the midpoint between the vesting date and the life of the SAR. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options. Of the 7.8 million outstanding at December 31, 2007, 3.7 million relates to stock options with the remainder of 4.1 million relating to SARs.

The total intrinsic value (the difference in value between exercise and market price) of stock options and SARs exercised during the years ended December 31, 2007 was $67.2 million compared to $37.1 million in 2006 and $15.2 million in 2005. As of December 31, 2007, the aggregate intrinsic value of the awards outstanding was $259.7 million. The aggregate intrinsic value and weighted average remaining contractual life of stock option awards currently exercisable was $169.7 million and 2.49 years. As of December 31, 2007, the number of fully-vested awards and awards expected to vest was 7.6 million. The weighted average exercise price and weighted average remaining contractual life of these awards were $17.70 and 2.89 years and the aggregate intrinsic value was $256.6 million. As of December 31, 2007, unrecognized compensation cost related to the awards was $17.6 million, which is expected to be recognized over a weighted average period of 0.84 years.

For the year ended December 31, 2007, total stock-based compensation expense for stock options and SARs under SFAS No. 123(R) was $15.2 million compared to $14.8 million in 2006. The total related tax benefits were $3.9 million. For the year ended December 31, 2007, cash received upon exercise of stock option awards was $16.2 million. Due to the net operating loss carryforward for tax purposes, tax benefits realized for deductions that were in excess of the stock-based compensation expense were not recognized.

Restricted Stock Grants

In 2007, we issued 435,000 shares of restricted stock grants as compensation to directors and employees, at an average price of $34.85. The restricted grants included 15,900 issued to directors, which vest immediately, and 419,100 to employees with vesting over a three-year period. In 2006, we issued 499,200 shares of restricted stock grants as compensation to directors and employees, at an average price of $24.43. The restricted grants included 15,000 issued to directors, which vest immediately, and 484,200 to employees with vesting over a three-to-four year period. We recorded compensation expense for restricted stock grants of $8.7 million in the year ended December 31, 2007 compared to $4.3 million in 2006 and $942,000 in 2005. As of December 31, 2007, there was $28.5 million of unrecognized compensation related to restricted stock awards expected to be recognized over the next three years. The vesting of these shares is dependent only upon the employees continued service with us. For restricted stock grants, the fair value is equal to the closing price of our common stock on the grant date. All of our restricted stock grants are held in our deferred compensation plan (see discussion below). The proceeds received from the sale of stock held in our deferred compensation plan was $6.5 million in 2007. All awards are issued at the market price at the time of the grant.

A summary of the status of our non-vested restricted stock outstanding at December 31, 2007 and changes during the twelve months then ended, is presented below:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2006	470,297	$ 24.00
Granted	435,841	34.85
Vested	(302,617)	27.59
Forfeited	(39,861)	24.61
Non-vested shares outstanding at December 31, 2007	563,660	$ 30.42

401(k) Plan

We maintain a 401(k) Plan for our employees. The 401(k) Plan permits employees to contribute up to 50% of their salary (subject to Internal Revenue Service limitations) on a pretax basis. Historically, we have made discretionary contributions of our common stock to the 401(k) Plan annually. In 2005, we began matching contributions of up to 3% of salary in cash. Beginning in 2008, we will match up to 6% of salary in cash. All our contributions become fully vested after the individual employee has three years of service with us. In 2007, we contributed $2.3 million to the

401(k) Plan compared to $1.9 million in 2006 and $1.5 million in 2005. We do not require that employees hold the contributed Range stock in their account. Employees have a variety of investment options in the 401(k) Plan. Employees may, at any time, diversify out of our stock, based on their personal investment strategy.

Deferred Compensation Plan

In 1996, the Board of Directors adopted a deferred compensation plan (the Plan). The Plan gave directors, certain officers and key employees the ability to defer all or a portion of their salaries and bonuses and invests in Range common stock or makes other investments at the individual s discretion. Great Lakes Energy Partners (which we purchased in 2004) also had a deferred compensation plan that allowed certain employees to defer all or a portion of their salaries and bonuses and invest such amounts in certain investments at the employee s discretion. In December 2004, we adopted the Range Resources Corporation Deferred Compensation Plan (2005 Deferred Compensation Plan). The 2005 Deferred Compensation Plan is intended to operate in a manner substantially similar to the old plans, subject to new requirements and changes mandated under Section 409A of the Internal Revenue Code. The old plans will not receive additional contributions. The assets of all of the plans are held in a rabbi trust, which we refer to as the Rabbi Trust, and are therefore available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Our stock held in the Rabbi Trust is

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istreated as a liability award (as defined by SFAS No. 123(R)) as employees are allowed to take withdrawals from the Rabbi Trust either in cash or in Range stock. The vested portion of the stock held in the Rabbi Trust is adjusted to fair value each reporting period by a charge or credit to deferred compensation plan expense on our consolidated statement of operations. The assets of the Rabbi Trust, other than our common stock, are invested in marketable securities and reported at market value in other assets on our consolidated balance sheet. The deferred compensation liability on our consolidated balance sheet reflects the vested market value of the marketable securities held in the Rabbi Trust and the market value of the vested Range stock held in the Rabbi Trust. Changes in the market value of the marketable securities are reflected in accumulated other comprehensive income (loss), while changes in the fair value of the liability are charged or credited to deferred compensation plan expense each quarter. We recorded mark-to-market expenses of $28.3 million in 2007 compared to $6.9 million in 2006 and $29.5 million in 2005. The Rabbi Trust held 2,111,565 shares of Range stock at December 31, 2007 compared to 1,853,279 at December 31, 2006.

In the fourth quarter of 2007, we recorded adjustments that decreased deferred compensation plan expense by $12.4 million, decreased common stock held by deferred compensation plan (a contra-equity account) to zero, decreased the deferred compensation liability by $26.2 million, decreased additional paid-in capital by $16.8 million and increased accumulated other comprehensive income (loss) by $5.6 million. Such reclassifications and adjustments were the result of inappropriately adjusting our deferred compensation liability for market value changes in unvested shares held in the Rabbi Trust and inappropriately recording our common stock issued to the Rabbi Trust at grant date fair value as opposed to our cost basis. In addition, interest and dividends related to the marketable securities held in the Rabbi Trust were inappropriately recorded in accumulated other comprehensive loss. Of the $12.4 million decrease in deferred compensation expense, $7.1 million is related to periods prior to 2007 and $5.3 million is related to the first three quarters of 2007. We have also reclassified the December 31, 2006 common stock held by deferred compensation plan (a contra-equity account) of $22.1 million to additional paid-in capital along with $11.9 million in December 31, 2005 to conform to the 2007 balance sheet presentation.

(13) SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Net cash provided from continuing operations included:			
Income taxes paid (refunded from) to taxing authorities	$ (572)	$ 1,973	$ 615
Interest paid	71,708	55,925	34,148
Non-cash investing and finance activities:			
6.5 million shares issued for Stroud acquisition	$	$177,641	$
Stock options (652,000) issued in Stroud acquisition		9,478	
Asset retirement costs capitalized, excluding acquisitions [(a)]	(7,075)	25,821	(1,730)

(a) For information regarding purchase price allocations of businesses acquired see Note 3.

(14) COMMITMENTS AND CONTINGENCIES

Litigation

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

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Lease Commitments

We lease certain office space and equipment under cancelable and non-cancelable leases. Rent expense under such arrangements totaled $5.4 million in 2007 compared to $5.0 million in 2006 and $2.2 million in 2005. Future minimum rental commitments under non-cancelable leases having remaining lease terms in excess of one year are as follows (in thousands):

	Operating Lease Obligations
2008	$ 9,657
2009	9,730
2010	9,491
2011	8,081
2012	4,720
Thereafter	8,568
Sublease rentals	(1,045)
	$ 49,202

Other Commitments

We also have agreements in place to purchase seismic data. These agreements total $500,000 in 2008 and $300,000 in 2009. We have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally two to three 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 likely allow additional acreage to expire in the future.

(15) MAJOR CUSTOMERS

We market our production on a competitive basis. Gas is sold under various types of contracts including month-to-month, and one-to-five-year contracts. Oil purchasers may be changed on 30 days notice. The price for oil is generally equal to a posted price set by major purchasers in the area or is based on NYMEX pricing, adjusted for quality and transportation. We sell to oil and gas purchasers on the basis of price, credit quality and service. For the year ended December 31, 2007, we had no customers that accounted for 10% or more of total oil and gas revenues. For the year ended December 31, 2006, two customers each accounted for 10% or more of total oil and gas revenues and the combined sales to those customers accounted for 25% of total oil and gas revenues. For the year ended December 31, 2005, four customers each accounted for 10% or more of total oil and gas revenue and combined sales to those four customers accounted for 56% of total oil and gas revenues. We believe that the loss of any one customer would not have a material adverse effect on our results.

(16) EQUITY METHOD INVESTMENTS

We account for our investments in entities over which we have significant influence, but not control, using the equity method of accounting. Under the equity method of accounting, we record our proportionate share of the net earnings, declared dividends and partnership distributions based on the most recently available financial statements of the investee. We also evaluate our equity method investments for potential impairment whenever events or changes in circumstances indicate that there is an other than temporary decline in value of the investment. Such events may include sustained operating losses by the investee or long-term negative changes in the investee s industry. These indicators were not present, and as a result, we did not recognize any impairment charges related to our equity method investments for the years ended December 31, 2007 or 2006.

Investment in Whipstock Natural Gas Services, LLC

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

50% of the membership interest in Whipstock.

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

Investment in Nora Gathering, LLC

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

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

(17) SUBSEQUENT EVENTS

In January 2008, we purchased producing and non-producing Barnett Shale properties for $284.2 million. The properties are located in Tarrant, Johnson, Ellis, Parker and Hill counties. Also in January 2008, we sold non-core oil properties located in East Texas for proceeds of $64.0 million. These properties included 99 shallow oil wells covering 5,600 net acres.

(18) SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years. As discussed in Note 2, certain reclassifications have been made to conform to our current year classifications. This includes the presentation of our Gulf of Mexico operations as discontinued operations, the reclassification of settled derivatives that do not qualify for hedge accounting from oil and gas sales to derivative fair value income (loss) and the reclassification of hedge ineffectiveness from other revenue to derivative fair value income (loss). These reclassifications did not impact net income. See also Note 12 for additional information on fourth quarter 2007 adjustments related to our deferred compensation plan.

			2007		
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 193,316	$ 213,896	$ 214,424	$ 240,901	$ 862,537
Transportation and gathering	184	511	508	1,087	2,290
Derivative fair value (loss) income	(42,620)	28,766	24,974	(18,887)	(7,767)
Other	1,961	341	2,447	282	5,031
Total revenues	152,841	243,514	242,353	223,383	862,091
Costs and expenses					
Direct operating	25,414	24,816	28,003	30,508	108,741
Production and ad valorem taxes	10,412	11,230	11,316	9,485	42,443
Exploration	11,710	11,725	6,233	13,677	43,345
General and administrative	14,678	17,838	18,058	17,854	68,428
Deferred compensation plan	11,247	9,334	7,761	(10)	28,332
Interest expense	18,848	17,573	19,935	21,381	77,737
Depletion, depreciation and amortization	47,332	51,465	57,001	71,530	227,328
Total costs and expenses	139,641	143,981	148,307	164,425	596,354
Income from continuing operations before income taxes	13,200	99,533	94,046	58,958	265,737
Income tax provision (benefit)					
Current	384	(101)	133	(96)	320
Deferred	4,447	34,449	34,802	24,743	98,441
	4,831	34,348	34,935	24,647	98,761
Income from continuing operations	8,369	65,185	59,111	34,311	166,976
Discontinued operations, net of taxes	64,768	(979)	(196)		63,593
Net income	$ 73,137	$ 64,206	$ 58,915	$ 34,311	$ 230,569

Earnings per common share:										
Basic income from continuing operations	$	0.06	$	0.45	$	0.40	$	0.23	$	1.16
discontinued operations		0.47		(0.01)						0.44
net income	$	0.53	$	0.44	$	0.40	$	0.23	$	1.60
Diluted income from continuing operations	$	0.06	$	0.43	$	0.39	$	0.22	$	1.11
discontinued operations		0.45								0.43
net income	$	0.51	$	0.43	$	0.39	$	0.22	$	1.54

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	2006				
	March	June	September	December	Total
Revenues					
Oil and gas sales	$ 150,658	$ 139,431	$ 153,054	$ 155,996	$ 599,139
Transportation and gathering	(39)	957	1,015	489	2,422
Derivative fair value income (loss)	28,598	29,316	65,490	18,991	142,395
Other	13	(314)	66	1,091	856
Total revenues	179,230	169,390	219,625	176,567	744,812
Costs and expenses					
Direct operating	18,133	16,933	22,336	23,859	81,261
Production and ad valorem taxes	9,551	8,545	9,874	8,445	36,415
Exploration	8,922	7,763	16,508	10,895	44,088
General and administrative	11,330	12,514	12,170	13,872	49,886
Deferred compensation plan	4,479	(2,188)	(2,638)	7,220	6,873
Interest expense	10,234	11,643	16,389	17,583	55,849
Depletion, depreciation and amortization	31,651	33,995	40,606	48,487	154,739
Total costs and expenses	94,300	89,205	115,245	130,361	429,111
Income from continuous operations before income taxes	84,930	80,185	104,380	46,206	315,701
Income tax					
Current	578	622	615	97	1,912
Deferred	31,150	29,676	38,707	20,307	119,840
	31,728	30,298	39,322	20,404	121,752
Income from continuing operations	53,202	49,887	65,058	25,802	193,949
Discontinued operations, net of taxes	2,473	1,383	(13,728)	(25,375)	(35,247)
Net income	$ 55,675	$ 51,270	$ 51,330	$ 427	$ 158,702
Earnings per common share:					
Basic income from continuing operations	$ 0.41	$ 0.38	$ 0.47	$ 0.19	$ 1.45
discontinued operations	0.02	0.01	(0.10)	(0.19)	(0.26)
net income	$ 0.43	$ 0.39	$ 0.37	$	$ 1.19

Earnings per common share:										
Diluted income from continuing operations	$	0.40	$	0.37	$	0.46	$	0.18	$	1.39
discontinued operations		0.01		0.01		(0.10)		(0.18)		(0.25)
net income	$	0.41	$	0.38	$	0.36	$		$	1.14

Principal Unconsolidated Investees (unaudited)

Company	December 31, 2007 Ownership	Activity
Whipstock Natural Gas Services, LLC	50%	Drilling services
Nora Gathering, LLC	50%	Gas gathering and transportation

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

The following information concerning our natural gas and oil operations has been provided pursuant to Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities, (SFAS No. 69). Our natural gas and oil producing activities are conducted onshore within the continental United States and offshore in the Gulf of Mexico. Our Gulf of Mexico assets were sold in the first quarter of 2007.

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

	December 31, 2007	2006 (in thousands)	2005
Oil and gas properties:			
Properties subject to depletion	$ 4,172,151	$ 3,132,927	$ 2,255,860
Unproved properties	271,426	226,166	28,453
Total	4,443,577	3,359,093	2,284,313
Accumulated depreciation, depletion and amortization	(939,769)	(751,005)	(604,720)
Net capitalized costs	$ 3,503,808	$ 2,608,088	$ 1,679,593

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

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

	Year Ended December 31, 2007	2006 (in thousands)	2005
Acquisitions:			
Unproved leasehold	$ 4,552	$ 132,821	$
Proved oil and gas properties	253,064	209,262	131,748
Purchase price adjustment [(b)]		147,062	20,966
Asset retirement obligations	3,301	896	119
Acreage purchases	78,095	79,762	20,674
Development	734,987	464,586	252,574
Exploration:			
Drilling	40,567	25,618	30,101
Expense	39,872	42,173	29,354
Stock-based compensation expense	3,473	3,079	1,250
Gas gathering facilities:			
Acquisitions			8
Exploratory		3,418	
Development	18,655	16,272	11,415

Subtotal	1,176,566	1,124,949	498,209
Asset retirement obligations	(7,075)	25,821	(1,730)
Total costs incurred [c]	$ 1,169,491	$ 1,150,770	$ 496,479
Assets held for sale:			
Acquisitions	$	$ 140,110	$
Development	$ 1,114	$ 15,012	$

(a) Includes cost incurred whether capitalized or expensed.

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

(c) 2006 includes $21.5 million related to our divested Gulf of Mexico properties compared to $14.8 million in 2005.

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

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

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

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

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

The average realized prices used at December 31, 2007 to estimate reserve information were $91.88 per barrel for oil, $52.64 per barrel for natural gas liquids and $6.44 per mcf for gas, using benchmark prices of $95.98 per barrel and $6.80 per Mmbtu. The average realized prices used at December 31, 2006 to estimate reserve information were $57.66 per barrel for oil, $25.98 per barrel for natural gas liquids and $5.24 per mcf for gas, using benchmark prices of $61.05 per barrel and $5.64 per Mmbtu. The average realized prices used at December 31, 2005 to estimate reserve information were $57.80 per barrel for oil, $36.00 per barrel for natural gas liquids and $9.83 per mcf for gas, using benchmark prices of $61.04 per barrel and $10.08 per Mmbtu. All of our proved reserves are located within the United States.

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	Crude Oil and NGLs (Mbbls)	Natural Gas (Mmcf)	Natural Gas Equivalents[b] (Mmcfe)
Proved developed and undeveloped reserves:			
Balance, December 31, 2004	38,166	946,428	1,175,425
Revisions	2,499	809	15,802
Extensions, discoveries and additions	7,932	169,785	217,377
Purchases	2,343	71,569	85,626
Property sales	(5)	(177)	(205)
Production	(4,043)	(63,004)	(87,263)
Balance, December 31, 2005	46,892	1,125,410	1,406,762
Revisions	(42)	(48,609)	(48,863)
Extensions, discoveries and additions	10,871	314,261	379,491
Purchases	242	121,683	123,133
Property sales	(4)	(1,500)	(1,522)
Production	(4,252)	(75,267)	(100,775)
Balance, December 31, 2006 [a]	53,707	1,435,978	1,758,226
Revisions	2,432	(386)	14,207
Extensions, discoveries and additions	13,741	401,805	484,250
Purchases	1,934	121,382	132,984
Property sales	(649)	(35,362)	(39,254)
Production	(4,505)	(90,620)	(117,651)
Balance, December 31, 2007	66,660	1,832,797	2,232,762
Proved developed reserves:			
December 31, 2005	33,029	724,876	923,050
December 31, 2006	37,750	875,395	1,101,895
December 31, 2007	47,015	1,144,709	1,426,802

(a) The December 31, 2006 balance excludes reserves associated with the Austin Chalk properties that are shown as Assets Held for Sale on our balance sheet. The total proved developed and undeveloped reserves for these assets at December 31, 2006 were 42.3 Bcfe which is comprised of 39.3 Bcfe of gas. These assets were sold in the first quarter of 2007.

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

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

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

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

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

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

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

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

	As of December 31,	
	2007	2006
	(in thousands)	
Future cash inflows	$ 17,231,826	$ 10,192,067
Future costs:		
Production	(3,859,591)	(2,575,212)
Development	(1,464,229)	(1,225,710)
Future net cash flows before income taxes	11,908,006	6,391,145
Future income tax expense	(3,854,952)	(1,999,934)
Total future net cash flows before 10% discount	8,053,054	4,391,211
10% annual discount	(4,386,691)	(2,388,987)
Standardized measure of discounted future net cash flows	$ 3,666,363	$ 2,002,224

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

	As of December 31,		
	2007	2006	2005
		(in thousands)	
Beginning of period	$ 2,002,224	$ 3,384,310	$ 1,749,411
Revisions of previous estimates:			
Changes in prices	1,310,378	(2,390,159)	1,633,812
Revisions in quantities	37,188	(91,793)	59,244
Changes in future development costs	(542,684)	(623,607)	(367,732)
Accretion of discount	277,144	488,737	239,636
Net change in income taxes	(769,242)	733,846	(856,115)
Purchases of reserves in place	348,119	231,314	321,022
Additions to proved reserves from extensions, discoveries and improved recovery	1,267,649	712,902	814,973
Production	(711,354)	(554,788)	(425,902)
Development costs incurred during the period	304,165	223,158	143,918
Sales of natural gas and oil	(102,757)	(2,859)	(769)
Timing and other	245,533	(108,837)	72,812
End of period	$ 3,666,363	$ 2,002,224	$ 3,384,310

RANGE RESOURCES CORPORATION
INDEX TO EXHIBITS

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated May 10, 2006, by and among Range Resources Corporation, Range Acquisition Texas, Inc. and Stroud Energy, Inc. (incorporated by reference to Exhibit 2.1 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 16, 2006)
3.1	Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to Exhibit 3.1.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on May 5, 2004) as amended by the Certificate of First Amendment to Restated Certificate of Incorporation of Range Resources Corporation (incorporated by reference to exhibit 3.1 to our Form 10-Q (File No. 001-12209) as filed with the SEC on July 28, 2005)
3.2	Amended and Restated By-laws of Range (incorporated by reference to Exhibit 3.2 to our Form 10-K (File No. 001-12209) as filed with the SEC on March 3, 2004)
4.1	Form of 7.375% Senior Subordinated Notes due 2013 (included as an exhibit to exhibit 4.2 hereto)
4.2	Indenture dated July 21, 2003 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors, and Bank One, National Association, as trustee (incorporated by reference to Exhibit 4.4.2 to our Form 10-Q (File No. 001-12209) as filed with the SEC on August 6, 2003)
4.3	Form of 6.375% Senior Subordinated Notes due 2015 (included as an exhibit to exhibit 4.4 hereto)
4.4	Indenture dated March 9, 2005 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors and J.P.Morgan Trust Company, National Association, as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on March 15, 2005)
4.5	Form of 7.5% Senior Subordinated Notes due 2016 (included as an exhibit to exhibit 4.6 hereto)
4.6	Indenture dated May 23, 2006 by and among Range, as issuer, the Subsidiary Guarantors (as defined herein), as guarantors and J.P.Morgan Trust Company, National Association as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on May 23, 2006)
4.7	Form of 7.5% Senior Subordinated Notes due 2017 (included as exhibit 4.8 hereto)
4.8	Indenture dated September 28, 2007 by and among Range, as issuer, the subsidiary Guarantors (as defined herein), as guarantors and J.P.Morgan Trust Company, National Association as trustee (incorporated by reference to Exhibit 4.1 on our Form 8-K (File No. 001-12209) as filed with the SEC on October 1, 2007)
10.1	Third Amended and Restated Credit Agreement as of October 25, 2006 among Range (as borrowers) and J.P.Morgan Chase Bank, N.A. and the institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent
10.2	First Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders,

	J.P.Morgan Chase as Administrative Agent (incorporated by reference to exhibit 10.1 to our Form-10Q (File No. 001-12209) as filed with the SEC April 26, 2007)
10.3	Second Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders, J.P.Morgan Chase as Administrative Agent (incorporated by reference to exhibit 10.1 to our Form-10Q (File No. 001-12209) as filed with the SEC April 26, 2007)
10.4*	Third Amendment to the Third Amended and Restated Credit Agreement dated October 26, 2006 among Range (as borrower) and J.P.Morgan Chase Bank, N.A. and institutions named (therein) as lenders
10.5	Range Resources Corporation Deferred Compensation Plan for Directors and Select Employees effective December 28, 2004 (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on January 3, 2005)
10.6	Form of Indemnity Agreement (incorporated by reference to Exhibit 10.5 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 18, 2005)
10.7	Range Resources Corporation 2005 Equity-Based Compensation (incorporated by reference to Exhibit 10.7 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 18, 2005)
10.8	First Amendment to the Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.8 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 18, 2005)
10.9	Second Amendment to the Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.2 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 26, 2006)
10.10	Third Amendment to the Range Resources Corporation 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 10.3 to our Form 8-K (File No. 001-12209) as filed with the SEC on May 26, 2006)
10.11	Fourth Amendment to the Range Resources 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 4.5 to our Form S-8 (File No. 333-143875) as filed with the SEC on June 19, 2007)
10.12	Fifth Amendment to the Range Resources 2005 Equity-Based Compensation Plan (incorporated by reference to Exhibit 4.6 to our Form S-8 (File No. 333-143875) as filed with the SEC on June 19, 2007)

Exhibit No.	Description
10.13	Lomak 1989 Stock Option Plan dated March 13, 1989 (incorporated by reference to Exhibit 10.1(d) to Lomak s Form S-1 (File No. 33-31558) as filed with the SEC on October 13, 1989)
10.14	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.1 to Lomak s Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.15	Amendment to the Lomak 1989 Stock Option Plan, as amended (incorporated by reference to Exhibit 4.2 to Lomak s Form S-8 (File No. 333-44821) as filed with the SEC on January 23, 1998)
10.16	Lomak 1994 Outside Directors Stock Option Plan (incorporated by reference to Exhibit 4.2 to Lomak s Form S-8 (File No. 333-10719) as filed with the SEC on August 23, 1996)
10.17	First Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 8, 1995 (incorporated by reference to Exhibit 4.6 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.18	Second Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated August 21, 1996 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.19	Third Amendment to the Lomak 1994 Outside Directors Stock Option Plan dated June 1, 1999 (incorporated by reference to Exhibit 4.8 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.20	Fourth Amendment to the Lomak 1994 Outside Directors Stock Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.9 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.21	2004 Non-Employee Director Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)
10.22	Lomak 1997 Stock Purchase Plan, as amended, dated June 19, 1997 (incorporated by reference to Exhibit 10.1(1) to Lomak s Form 10-K (File No. 001-12209) as filed with the SEC on March 20, 1998)
10.23	First Amendment to the Lomak 1997 Stock Purchase Plan dated May 26, 1999 (incorporated by reference to Exhibit 4.2 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.24	Second Amendment to the Lomak 1997 Stock Purchase Plan dated September 28, 1999 (incorporated by reference to Exhibit 4.3 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.25	Third Amendment to the Lomak 1997 Stock Purchase Plan dated May 24, 2000 (incorporated by reference to Exhibit 4.4 to our Form S-8 (File No. 333-40380) as filed with the SEC on June 29, 2000)
10.26	Fourth Amendment to the Lomak 1997 Stock Purchase Plan dated May 24, 2001 (incorporated by reference to Exhibit 4.7 to our Form S-8 (File No. 333-63764) as filed with the SEC on June 25, 2001)

10.27	Amended and Restated 1999 Stock Option Plan (as amended May 21, 2003) (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-105895) as filed with the SEC on June 6, 2003)
10.28	Fourth Amendment to the Amended and Restated 1999 Stock Option Plan dated May 19, 2004 (incorporated by reference to Exhibit 4.1 to our Form S-8 (File No. 333-116320) as filed with the SEC on June 9, 2004)
10.29	Range Resources Corporation 401(k) Plan (incorporated by reference to Exhibit 10.14 to our Form S-4 (File No. 333-108516) as filed with the SEC on September 4, 2003)
10.30	Range Resources Corporation Executive Change in Control Severance Benefit Plan dated March 28, 2005 (incorporated by reference to exhibit 10.1 to our Form 8-k (File No. 001-12209) as filed with the SEC on March 31, 2005)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Independent Registered Public Accounting Firm
23.2*	Consent of H.J. Gruy and Associates, Inc., independent consulting engineers
23.3*	Consent of DeGoyler and MacNaughton, independent consulting engineers
23.4*	Consent of Wright and Company, independent consulting engineers
31.1*	Certification by the President and Chief Executive Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer of Range Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification by the President and Chief Executive Officer of Range Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification by the Chief Financial Officer of Range Pursuant to 18 U.S.C. Section 350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* Filed herewith.

** Furnished herewith.