CIMAREX ENERGY CO
Form 10-K
February 28, 2007

united states

securities and exchange commission

Washington, D C 20549

Form 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2006

OR

o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission file number 001-31446

CIMAREX ENERGY CO.

(Exact name of registrant as specified in its charter)

Delaware	**45-0466694**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1700 Lincoln Street, Suite 1800, Denver, Colorado 80203

(Address of principal executive offices including ZIP code)

(303) 295-3995

(Registrant s telephone number)

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 is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES x 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 x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO 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 the 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, or a non-accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). (Check One):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act. YES o NO x

Aggregate market value of the voting stock held by non-affiliates of Cimarex Energy Co. as of June 30, 2006 was approximately $3,403,194,051.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 15, 2007 was 83,245,444.

Documents Incorporated by Reference: Portions of the Registrant s Proxy Statement for its 2007 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

DESCRIPTION

GLOSSARY

Bbl/d **Barrels** (of oil) per day
Bbls **Barrels** (of oil)
Bcf **Billion** cubic feet
Bcfe **Billion** cubic feet equivalent
MBbls **Thousand** barrels
Mcf **Thousand** cubic feet (of natural gas)
Mcfe **Thousand** cubic feet equivalent
MMBbls **Million** barrels
MMBtu **Million** British Thermal Units
MMcf **Million** cubic feet
MMcf/d **Million** cubic feet per day
MMcfe **Million** cubic feet equivalent
MMcfe/d **Million** cubic feet equivalent per day
Net Acres **Gross** acreage multiplied by working interest percentage
Net Production **Gross** production multiplied by net revenue interest
NGL **Natural** gas liquids
Tcf **Trillion** cubic feet
Tcfe **Trillion** cubic feet equivalent

One barrel of oil is the energy equivalent of six Mcf of natural gas.

PART I

Forward-Looking Statements

Throughout this Form 10-K, we make statements that may be deemed 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. All statements, other than statements of historical facts, that address activities, events, outcomes and other matters that Cimarex plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. These forward-looking statements are based on management s current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K. Forward-looking statements include statements with respect to, among other things:

- *amount, nature and timing of capital expenditures;*
- *drilling of wells;*
- *reserve estimates;*
- *timing and amount of future production of oil and natural gas;*
- *operating costs and other expenses;*
- *cash flow and anticipated liquidity;*
- *estimates of proved reserves, exploitation potential or exploration prospect size; and*
- *marketing of oil and natural gas.*

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures and other risks described herein.

Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of such data by our engineers. As a result, estimates made by different engineers often vary from one another. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the timing of future production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties above or elsewhere in this Form 10-K cause our underlying assumptions to be incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, express or implied, included in this Form 10-K and attributable to Cimarex are qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that Cimarex or persons acting on its behalf may issue. Cimarex does not undertake any obligation to update any forward-looking statements to reflect events or circumstances after the date of filing this Form 10-K with the Securities and Exchange Commission, except as required by law.

ITEM 1. BUSINESS

General

Cimarex Energy Co. is an independent oil and gas exploration and production company. Our operations are mainly located in Texas, Oklahoma, New Mexico, Louisiana and the Gulf of Mexico. Proved oil and gas reserves as of year-end 2006 totaled nearly 1.45 Tcfe, consisting of 1.1 Tcf of gas and 59.8 million barrels of oil and natural gas liquids. Of total proved reserves, 75 percent are gas and 80 percent are classified as proved developed. We operate the wells that account for 73 percent of our total proved reserves and approximately 70 percent of production.

Cimarex was formed in February 2002 as a wholly owned subsidiary of Tulsa-based Helmerich & Payne, Inc. On September 30, 2002, Cimarex was completely spun off to Helmerich and Payne shareholders and simultaneously merged with Denver-based Key Production Company, Inc. Our common stock began trading on the New York Stock Exchange on October 1, 2002 under the symbol XEC.

On June 7, 2005, Cimarex acquired Dallas-based Magnum Hunter Resources, Inc. in a $1.5 billion stock-for-stock merger plus assumption of liabilities. Proved reserves acquired totaled 886.7 billion cubic feet equivalent (Bcfe), of which 60 percent were gas and 73 percent proved developed. The transaction effectively tripled our proved reserves and doubled our production.

Our corporate headquarters are located at 1700 Lincoln Street, Suite 1800, Denver, Colorado 80203 and our main telephone number at that location is (303) 295-3995.

Our Web site address is www.cimarex.com. There you will find our news releases, annual reports, proxy statements, 10-Ks, 10-Qs, 8-Ks, insider (Section 16) filings and all other SEC filings. We have also posted our Code of Ethics, Code of Business Conduct, Corporate Governance Guidelines, Audit Committee Charter and Governance Committee Charter. Copies of these documents are also available in print upon a written or telephone request to our Corporate Secretary.

Business Strategy

Our basic business approach is centered on profitable reinvestment of the cash flow generated by our producing properties in drilling new wells that have the potential to grow our production and proved reserves and to add value for the benefit of our investors. A cornerstone to our approach is detailed evaluation of each drilling decision based on its risk-adjusted discounted after-tax cash flow rate of return on investment. Our analysis includes estimates and assessments of potential reserve size, geologic and mechanical risks, expected costs and future production profiles.

During 2006, we drilled 558 gross wells and invested $1,049 million on exploration and development. Our integrated teams of geoscientists, landmen, and petroleum engineers continually generate new prospects to maintain a rolling portfolio of drilling opportunities in different basins with varying geologic characteristics. We have a centralized exploration management system that measures actual results and provides feedback about drilling results to the originating exploration teams in order to help them improve and refine future investment decisions. We believe that our detailed technical analysis and disciplined risk assessment is a competitive advantage and best positions us to continue to achieve attractive economic rates of return and consistent increases in proved reserves and production.

While our primary focus is drilling, we do consider acquisition and merger opportunities that allow us to either enhance our competitive position in existing core areas or to add new areas. The Magnum Hunter acquisition significantly increased our presence in the Permian Basin and enhanced our Mid-Continent operations in the Texas Panhandle.

Business Segments

Cimarex has one reportable segment (exploration and production).

Exploration and Development Activity Overview

Our operations are currently focused in the Mid-Continent region which consists of Oklahoma, the Texas Panhandle and southwest Kansas; the Permian Basin region of west Texas and southeast New Mexico; the upper Gulf Coast areas of Texas, south Louisiana and Mississippi; and the Gulf of Mexico.

A summary of our 2006 exploration and development activity by region is as follows.

	Exploration and Development Capital (in millions)	Gross Wells Drilled	Net Wells Drilled	Completion Rate	12/31/06 Proved Reserves (Bcfe)
Mid-Continent	$ 350	302	186	97 %	595
Permian Basin	331	167	119	96 %	563
Gulf Coast	211	49	28	65 %	105
Gulf of Mexico	128	16	6	44 %	44
Western/Other	29	24	7	71 %	142
	$ 1,049	558	346	91 %	1,449

Company-wide, we participated in drilling 558 gross wells during 2006, with an overall completion rate of 91 percent. On a net basis, 316 of 346 total wells drilled during 2006 were completed as producers.

Our 2006 exploration and development expenditures (E&D) totaled $1,049 million and resulted in 201 Bcfe of proved reserve additions from drilling. Of total expenditures, 33 percent were invested in projects located in the Mid-Continent area; 32 percent in the Permian Basin; 20 percent in the Gulf Coast; and 12 percent in the Gulf of Mexico.

Mid-Continent

Our Mid-Continent operations cover the Anadarko and Arkoma basins of central and southeastern Oklahoma, the Hugoton Basin of southwest Kansas and the Texas Panhandle. We drilled 302 gross (186 net) Mid-Continent wells during 2006, completing 97 percent as producers. The bulk of this activity occurred in the Texas Panhandle and the Anadarko Basin. Full-year 2006 drilling investment in this area totaled $350 million, or 33% of total E&D capital.

We drilled 86 gross (59 net) Texas Panhandle wells with 98 percent being completed as producers. Most of these wells targeted the Granite Wash formation in Roberts and Hemphill counties at depths ranging from 11,000-14,000 feet. Drilling activity in the Granite Wash remains active with 75-100 wells planned for 2007.

We drilled 92 (18 net) Anadarko Basin wells, of which 98 percent were completed as producers. The drilling activity mainly targets the Red Fork and Clinton Lake/Atoka formations at depths ranging from 12,000-15,000 feet. Gross proved reserves for these wells averaged 1.3 Bcfe. We expect to continue an active program in this area, drilling a similar number of wells in 2007 as in 2006.

We have a large inventory of recompletion and in-fill drilling locations in several exploitation projects, including the Cumberland, Madill and Caddo fields in southern Oklahoma and the Panoma field in the Texas Panhandle. The Panoma field area targets the Brown Dolomite formation at depths of approximately 2,200 feet. In 2006 we drilled 80 gross (79 net) wells at Panoma with a 100% success rate, increasing field production by 3.2 MMcfe/d.

Permian Basin

In the Permian Basin our operations cover both west Texas and southeast New Mexico. In total, we drilled 167 gross (119 net) wells completing 161 gross (115 net) as producers in the Permian Basin during 2006. Full-year 2006 drilling investment in this area totaled $331 million, or 32% of total E&D capital.

Southeast New Mexico drilling totaled 69 gross (47 net) wells with 94% being completed as producers. The primary formations we target in this area are comprised of Pennsylvanian-aged Morrow, Atoka and Strawn sandstones and conglomerate gas reservoirs at depths ranging from 11,500-14,000 feet.

In West Texas, a total of 98 gross (72 net) wells were drilled, of which 98% were successful. Included in the West Texas program is exploitation of the Westbrook Unit (90% working interest) where 44 infill wells have been drilled and completed in the Clearfork formation at 3,200 feet.

Other geologic targets in West Texas include the Devonian, Ellenburger, Bone Spring and Spraberry. We drilled or participated in 21 (seven net) Devonian wells in the Arbol de Nada field in Winkler and Ector Counties, Texas; five gross (five net) Ellenburger wells in the Will-O field in Val Verde County, Texas; and six gross (2.7 net) Bone Spring wells in the War-Wink field in Ward County, Texas.

Gulf Coast /Gulf of Mexico

Our onshore Gulf Coast focus area generally encompasses coastal Texas, south Louisiana and Mississippi. Our Gulf of Mexico operations are primarily located in offshore Louisiana in water depths less than 300 feet and covering approximately one million gross acres. We obtained all of our offshore position through the Magnum Hunter acquisition. Our Gulf Coast and Gulf of Mexico effort is generally characterized by a greater reliance on 3-D seismic information for prospect generation, larger potential reserves per well, greater drilling depths and lower success rates.

During 2006 we drilled 49 gross (28 net) Gulf Coast wells, realizing a 65 percent success rate. A significant portion of the drilling occurred in Liberty County, Texas. Targeting the Yegua and Cook Mountain formations at 10,500 feet, we drilled 14 gross (nine net) Liberty County wells with a success rate of 64 percent. Gulf of Mexico 2006 drilling consisted of 16 gross (6.7 net) wells, of which 44% were successful.

Western/Other

Our Western/Other region principally includes operations in California, Michigan, North Dakota and Wyoming. We drilled 24 gross (7.2 net) wells in the Western/Other region completing only 17 gross (0.2 net) as producers. Included in this area is the Riley Ridge Unit gas development project in Sublette County, Wyoming.

Production and Pricing Information

The following table sets forth certain information regarding the company s production volumes and the average oil and gas prices received:

	Years Ending December 31,		
	2006	**2005**	**2004**
Production Volumes			
Gas (MMcf)	124,733	100,272	63,611
Oil (MBbls)	6,529	4,804	2,641
Equivalent (MMcfe)	163,907	129,096	79,457
Net Average Daily Volumes:			
Gas (MMcf)	341.7	274.7	173.8
Oil (MBbl)	17.9	13.2	7.2
Equivalent (MMcfe)	449.1	353.7	217.1
Average Sales Price			
Gas ($/Mcf)	$ 6.50	$ 8.05	$ 5.76
Oil ($/Bbl)	$ 61.96	$ 55.25	$ 40.19

Combined oil and gas production volumes increased 27 percent to 449.1 MMcfe per day. Gas production in 2006 rose 24 percent to 341.7 MMcf per day and oil production increased 36 percent to 17,887 barrels per day. The increase in volumes primarily stems from the inclusion of production from Magnum Hunter operations beginning June 7, 2005 and exploration and development drilling.

The weighted-average gas price we received during 2006 was $6.50 per Mcf, which was 19 percent lower than the $8.05 per Mcf average price we received during 2005. Our annual average realized oil price during 2006 increased by 12 percent to $61.96 per barrel from $55.25 per barrel in 2005. Gas prices fell in 2006 as compared to 2005 as a result of a number of factors including lower demand because of warm winter weather, no significant hurricane activity causing supply disruptions in the Gulf of Mexico and rising storage levels relative to historic averages.

Cimarex assumed Magnum Hunter s oil and gas commodity swap and collar contracts as part of the merger. These instruments did not qualify for hedge accounting treatment and as such they are not included in the above average sales prices. In third quarter of 2006, we entered into natural gas collars for calendar 2007 and 2008 for 80,000 and 40,000 MMBtu per day, respectively. The collars have been executed to settle against regional delivery points that correspond with our Mid-Continent production. Beginning in January 2007, these instruments will affect average sales prices to the extent that the benchmark prices fall outside the collar range. For a discussion of derivatives, see Note 5 of Notes to Consolidated Financial Statements contained herein.

The following table summarizes Cimarex s daily production by region for the full-year 2006 and the second-half of 2005. The second-half 2005 volumes reflect the production increases as a result of the Magnum Hunter acquisition.

	2006 Average Daily Production			**Second-half**
	Oil (MBbl/d)	**Gas (MMcf/d)**	**Total (MMcfe/d)**	**2005 Avg. (MMcfe/d)**
Mid-Continent	4.7	152.5	180.7	175.3
Permian Basin	8.1	83.8	132.4	130.1
Gulf Coast	3.2	61.8	80.7	84.4
Gulf of Mexico	1.6	36.2	45.9	37.9
Other	0.3	7.4	9.4	10.5
	17.9	341.7	449.1	438.2

Our largest producing area is the Mid-Continent region which averaged 180.7 MMcfe per day making-up 40 percent of our total 2006 production. We grew our 2006 production in this region as a result of successful drilling programs in the Texas Panhandle and the Anadarko Basin. The Permian Basin contributed 132.4 MMcfe per day in 2006, which was 29 percent of our total production for this period. The current year production increased as a result of successful Morrow drilling in southeast New Mexico and West Texas secondary oil projects and development drilling. Gulf Coast production was 80.7 MMcfe per day during 2006, or 18 percent of total production. Gulf Coast volumes decreased in 2006 as a result of natural decline in our wells which were only partially offset by exploration success. Production from the Gulf of Mexico totaled 45.9 MMcfe per day, or 10 percent of our total 2006 production. Our second-half 2005 Gulf of Mexico production rate of 37.9 MMcfe per day was negatively impacted by hurricanes.

We have field offices located near our major concentrations of operated properties and have a centralized production management team in our Tulsa office.

Acquisitions and Divestitures

Cimarex completed its acquisition of Magnum Hunter Resources, Inc, on June 7, 2005. Magnum Hunter was an independent oil and gas exploration and production company with operations concentrated in the Permian Basin of West Texas and southeast New Mexico and in the Gulf of Mexico. Magnum s oil and gas properties were valued at $1.8 billion and resulted in the addition of 886.7 Bcfe of proved reserves (73 percent proved developed).

Various interests in oil and gas properties were sold during 2006, with proceeds totaling $4.5 million. Proceeds from the sales were recorded as a reduction to oil and gas properties, as prescribed under the full cost method of accounting. Proved reserves associated with the sold properties approximated 2.5 billion cubic feet equivalent. We also recognized a $19.8 million gain on sale of certain limited partnership interests in oil and gas properties. Net sales consideration received via distributions from these affiliated partnerships totaled $59.3 million.

Marketing

Our oil and gas production is sold under various short-term arrangements at market-responsive prices. We sell our oil at various prices directly or indirectly tied to field postings and monthly futures contract prices on the New York Mercantile Exchange (NYMEX). Our gas is sold under pricing mechanisms related to either monthly index prices on pipelines where we deliver our gas or the daily spot market. Revenues are recognized as gas is delivered and are reflected net of gas purchases in the Consolidated Statement of Operations included in this report.

We sell our oil and gas to a broad portfolio of customers. Our largest customer accounted for 11 percent of 2006 revenues. Because over two-thirds of our gas production is from wells in Kansas, Oklahoma, Texas and Louisiana, most of our customers are either from those states or nearby end-user market centers. We regularly monitor the credit worthiness of all our customers and may require parental guarantees, letters of credit or prepayments when we deem such security is necessary.

Employees

We employed 734 people on December 31, 2006. None of our employees are subject to collective bargaining agreements.

Competition

The oil and gas industry is highly competitive. Competition is particularly intense for prospective undeveloped leases and purchases of proved oil and gas reserves. There is also competition for rigs and related equipment we use to drill for and produce oil and gas. Our competitive position is also highly dependent on our ability to recruit and retain geological, geophysical and engineering expertise. We compete for prospects, proved reserves, oil-field services and qualified oil and gas professionals with major and diversified energy companies and other independent operators that have larger financial, human and technological resources than we do.

We compete with integrated, independent and other energy companies for the sale and transportation of oil and gas to marketing companies and end users. The oil and gas industry competes with other energy industries that supply fuel and power to industrial, commercial and residential consumers. Many of these competitors have financial and human resources substantially larger than those of Cimarex. The effect of these competitive factors on Cimarex cannot be predicted.

Title to Oil and Gas Properties

We undertake title examination and perform curative work at the time we lease undeveloped acreage, prepare for the drilling of a prospect or acquire proved properties. We believe that the titles to our properties are good and defensible, and are in accordance with industry standards. Our oil and gas properties are subject to customary royalty interests contracted for in connection with the acquisition of title, liens incidental to operating agreements, tax liens and other burdens and minor encumbrances, easements and restrictions.

Government Regulation

Oil and gas production and transportation is subject to many varying and complex federal and state regulations. In recent years, we have been most directly affected by federal and state environmental regulations and energy conservation rules. We are indirectly affected by federal and state regulation of pipelines and other oil and gas transportation systems. Compliance with such laws and regulations increases our overall cost of business, but has not had a material adverse effect on our operations or financial condition.

Most of the states in which we conduct operations regulate the size of well spacing units, drilling density within productive formations and the unitization or pooling of properties. In addition, state conservation laws establish limits on the maximum rate of production from wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to often limit the amounts of oil and natural gas that we can produce from our wells and to limit the number of wells or locations at which we can drill.

Environmental Regulation. Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, and consequently may impact our operations and costs. These laws and regulations govern, among other things, emissions to the atmosphere, discharges of pollutants into waters, underground injection of waste water, the generation, storage, transportation and disposal of waste materials, and protection of public health, natural resources and wildlife. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas. To date, we have not expended any material amounts to comply with such regulations, and management does not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position or results of operations.

We are committed to environmental protection and believe we are in substantial compliance with applicable environmental laws and regulations. We routinely obtain permits for our facilities and operations in accordance with the applicable laws and regulations. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations. We have made, and will continue to make, expenditures in our efforts to comply with environmental regulations and requirements. These costs are considered a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with government regulations.

Gas Gathering and Transportation. The Federal Energy Regulatory Commission (FERC) requires interstate gas pipelines to provide open access transportation. Interstate pipelines have implemented this requirement by modifying their tariffs and implementing new services and rates. These changes have provided us with additional market access and more fairly applied transportation services and rates. FERC continues to review and modify its open access and other regulations applicable to interstate pipelines.

Under the Natural Gas Policy Act (NGPA), natural gas gathering facilities are expressly exempt from FERC jurisdiction. What constitutes gathering under the NGPA has evolved through FERC decisions and judicial review of such decisions. We believe that our gathering systems meet the test for non-jurisdictional gathering systems under the NGPA and that our facilities are not subject to federal regulations. Although exempt from federal regulatory oversight, our natural gas gathering systems and services may receive regulatory scrutiny by state agencies.

Additional proposals and proceedings that might affect the oil and gas industry are pending before the U.S. Congress, FERC, state legislatures, state agencies and the courts. We cannot predict when or whether any such proposals may become effective and what effect they will have on our operations. We do not anticipate that compliance with existing federal, state and local laws, rules or regulations will have a material adverse effect upon our capital expenditures, earnings or competitive position.

In addition to using our own gathering facilities, we may use third-party gathering services or interstate transmission facilities (owned and operated by interstate pipelines) to ship our gas to markets.

Federal and State Income Taxation

Cimarex and the petroleum industry in general are affected by both federal and state income tax laws. We have considered the effects of these provisions on our operations and do not anticipate that there will be any undisclosed impact on our capital expenditures, earnings or competitive position.

Certain Risks

The following risks and uncertainties, together with other information set forth in this Form 10-K, should be carefully considered by current and future investors in our securities. If any of the following risks and uncertainties develop into actual events, this could have a material adverse affect on our business, financial condition or results of operations and could negatively impact the value of our common stock.

Low oil and gas prices could adversely affect our financial results and future rate of growth in proved reserves and production.

Our revenues and results of operations are highly dependent on oil and gas prices. The prices we receive for our production are based on prevailing market conditions and are influenced by many factors that are beyond our control. Historically, oil and gas prices have fluctuated widely. For example, in 2006 we sold our gas at an average price of $6.50 per Mcf, which was 19 percent lower than our 2005 average sales price of $8.05 per Mcf. Conversely, our average 2006 oil price of $61.96 per barrel was 12 percent higher than the price we received in 2005 of $55.25 per barrel.

In recent years, oil prices have responded to changes in supply and demand stemming from actions taken by the Organization of Petroleum Exporting Countries, worldwide economic conditions, growing transportation and power generation needs, and other events. Factors affecting gas prices have included domestic supplies; the level and price of natural gas imports into the U.S.; weather conditions; the economy and the price and level of alternative sources of energy such as nuclear power, hydroelectric power, coal, and other petroleum products.

Our proved oil and gas reserves and production volumes will decrease in quantity unless we successfully replace the reserves we produce with new discoveries or acquisitions. For the foreseeable future, we expect to make substantial capital investments for the exploration and development of new oil and gas reserves to replace the reserves we produce and to increase our total proved reserves. Historically, we have paid for these types of capital expenditures with cash flow provided by our production operations. Because low oil and gas prices would negatively affect the amount of cash flow available to fund these capital investments, they could also affect our future rate of growth. Low prices may also reduce the amount of oil and gas that we can economically produce and may cause us to curtail, delay or defer certain exploration and development projects. We may be required under accounting rules to write down the carrying value of our properties or impair goodwill when gas and oil prices are low. Moreover, our ability to borrow under our bank credit facility and to raise additional debt or equity capital to fund acquisitions would also be impacted.

Our use of hedging arrangements could result in financial losses or reduce our income.

To reduce our exposure to fluctuations in natural gas prices, we have entered into hedging arrangements for a portion of our natural gas production. These hedging arrangements expose us to risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the hedging contract defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

Failure of our exploration and development program to find commercial quantities of new oil and gas reserves could negatively affect our financial results and future rate of growth.

Most of our wells produce from reservoirs characterized by high levels of initial production and declines which stabilize within three to five years. In order to replace the reserves depleted by production and to maintain or grow our total proved reserves and overall production levels, we must locate and develop new oil and gas reserves or acquire producing properties from others. While we may from time to time seek to acquire proved reserves, our main business strategy is to grow through drilling. Without successful exploration and development, our reserves, production and revenues could decline rapidly, which would negatively impact our results of operations and reduce our ability to raise capital.

Exploration and development involves numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. Exploration and development can also be unprofitable, not only from dry wells, but from productive wells that do not produce sufficient reserves to return a profit.

We often are uncertain as to the future cost or timing of drilling, completing and producing wells. Our drilling operations may be curtailed, delayed or canceled as a result of several factors, including unforeseen poor drilling conditions, title problems, unexpected pressure or irregularities in formations, equipment failures, accidents, adverse weather conditions, compliance with environmental and other governmental requirements, and the cost of, or shortages or delays in the availability of, drilling rigs and related equipment.

The high-rate production characteristics of our properties subject us to high reserve replacement needs and require significant capital expenditures to replace our reserves.

Unless we conduct successful development activities or acquire properties containing proved reserves, our proved reserves will decline as they are produced. Producing natural gas and oil reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics and other factors. Because of the high-rate production profiles of our properties, replacing produced reserves is more difficult for us than for companies whose reserves have longer-life production profiles. This imposes greater reinvestment risk for our company as we may not be able to continue to economically replace our reserves.

Our proved reserve estimates may be inaccurate and future net cash flows are uncertain.

Estimates of proved oil and gas reserves and their associated future net cash flow necessarily depend on a number of variables and assumptions. Among others, changes in any of the following factors may cause estimates to vary considerably from actual results:

- production rates, reservoir pressure, and other subsurface information;
- future oil and gas prices;

- assumed effects of governmental regulation;
- future operating costs;
- future property, severance, excise and other taxes incidental to oil and gas operations;
- capital expenditures;
- workover and remedial costs; and
- Federal and state income taxes.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with guidelines established by the Securities and Exchange Commission (SEC). DeGolyer and MacNaughton, independent petroleum engineers, reviewed our reserve estimates for properties that comprised at least 80 percent of the discounted future net cash flows before income taxes, using a 10 percent discount rate, as of December 31, 2006.

The values referred to in this report should not be construed as the current market value of our proved reserves. In accordance with SEC guidelines, the estimated discounted net cash flow from proved reserves is based on prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially different.

We deliver oil and gas through pipelines that we do not own. The marketability of our production depends in part upon the availability, proximity and capacity of these pipelines. These facilities may not always be available to us in the future. The lack of availability of these facilities for an extended period of time could negatively affect revenues.

Competition in our industry is intense and many of our competitors have greater financial and technological resources.

We operate in the competitive area of oil and gas exploration and production. Many of our competitors are large, well-established companies that have larger operating staffs and greater capital resources than we do. These companies may be able to pay more for exploratory prospects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit.

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and gas are subject to extensive Federal, state and local laws and regulations, including complex environmental laws. We may be required to make large expenditures to comply with environmental and other governmental regulations. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, spacing of wells, unitization and pooling of properties, environmental protection, and taxation. Our operations create the risk of environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water. In the event of environmental violations, we may be charged with remedial costs. Pollution and similar environmental risks generally are not fully insurable. Such liabilities and costs could have a material adverse effect on our financial condition and results of operations.

Our limited ability to influence operations and associated costs on properties not operated by us could result in economic losses that are partially beyond our control.

Other companies operate approximately 30 percent of our net production. Our success in properties operated by others depends upon a number of factors outside of our control, including timing and amount of capital expenditures, the operator s expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. Our dependence on the operator and other working interest owners for these projects could prevent the realization of our targeted returns on capital in drilling or acquisition activities.

Our business involves many operating risks that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to hazards and risks inherent in drilling for oil and gas, such as fires, natural disasters, explosions, formations with abnormal pressures, casing collapses, uncontrollable flows of underground gas, blowouts, surface cratering, pipeline ruptures or cement failures, and environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases. Any of these risks can cause substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, regulatory investigations and penalties, suspension of our operations and repair and remediation costs. In addition, our liability for environmental hazards may include conditions created by the previous owners of properties that we purchase or lease.

We maintain insurance coverage against some, but not all, potential losses. We do not believe that insurance coverage for all environmental damages that could occur is available at a reasonable cost. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operation.

We have outstanding Convertible Notes which are convertible into our common stock.

We have outstanding $125 million of Convertible Notes (face value) that mature on December 15, 2023. The Convertible Notes will be convertible into a combination of cash and common stock of Cimarex upon the happening of certain events. In general, upon conversion of a Convertible Note, the holder would receive cash equal to the principal amount of the Convertible Note and Cimarex common stock for the Convertible Note s conversion value in excess of such principal amount. The number of Cimarex common shares into which the Convertible Notes are convertible is dependent upon the conversion value in excess of the principal amount of the Convertible Notes and our future common stock price. Any such conversion will be dilutive to our existing shareholders.

Our acquisition activities may not be successful, which may hinder our replacement of reserves and adversely affect our results of operations.

We evaluate opportunities and engage in bidding and negotiating for acquisitions, some of which are substantial. Under certain circumstances, we may pursue acquisitions of businesses that complement or expand our current business and acquisition and development of new exploration prospects that complement or expand our prospect inventory. We may not be successful in identifying or acquiring any material property interests, which could hinder us in replacing our reserves and adversely affect our financial results and rate of growth. Even if we do identify attractive opportunities, there is no assurance that we will be able to complete the acquisition of the business or prospect on commercially acceptable terms. If we do complete an acquisition, we must anticipate difficulties in integrating its operations, systems, technology, management and other personnel with our own. These difficulties may disrupt our ongoing operations, distract our management and employees and increase our expenses.

Competition for experienced, technical personnel may negatively impact our operations.

Our exploratory and development drilling success depends, in part, on our ability to attract and retain experienced professional personnel. The loss of any key executives or other key personnel could have a material adverse effect on our operations. As we continue to grow our asset base and the scope of our operations, our future profitability will depend on our ability to attract and retain qualified personnel, particularly individuals with a strong background in geology, geophysics, engineering and operations.

There are inherent limitations in all control systems, and misstatements due to error or fraud may occur and not be detected.

While Cimarex has taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in its ability to control all circumstances. See Item 9A of this report for a complete discussion of controls and procedures. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions, such as growth of the company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a control system, misstatements due to error or fraud may occur and not be detected.

The Cimarex certificate of incorporation, by-laws and stockholders rights plan include provisions that could discourage an unsolicited corporate takeover and could prevent stockholders from realizing a premium on their investment.

The certificate of incorporation and by-laws of Cimarex provide for a classified board of directors with staggered terms, restrict the ability of stockholders to take action by written consent and prevent stockholders from calling a meeting of the stockholders. In addition, Delaware General Corporation Law imposes restrictions on business combinations with interested parties. Cimarex also has adopted a stockholders rights plan. The stockholders rights plan, the certificate of incorporation and the by-laws may have the effect of delaying, deferring or preventing a change in control of Cimarex, even if the change in control might be beneficial to Cimarex stockholders.

ITEM 2. PROPERTIES

Oil and Gas Properties and Reserves

All of our proved reserves and undeveloped acreage are located in the United States. We have varying levels of ownership interests in our properties consisting of working, royalty and overriding royalty interests. We operate the wells that comprise 73 percent of our proved reserves.

Our engineers estimate our proved oil and gas reserve quantities in accordance with guidelines established by the SEC. DeGolyer and MacNaughton, independent petroleum engineers, reviewed our reserve estimates for those properties that comprised at least 80 percent of the discounted value of the projected future net cash flow before income taxes as of December 31, 2006. All information in this Form 10-K relating to oil and gas reserves is net to our interest unless stated otherwise. See Note 17, Supplemental Oil and Gas Disclosures, in Notes to Consolidated Financial Statements for further information. The following table sets forth the present value and estimated volume of our oil and gas proved reserves:

	Years Ending December 31, 2006	2005	2004
Total Proved Reserves			
Gas (MMcf)	1,090,362	1,004,482	364,641
Oil, condensate and NGLs (MBbls)	59,797	64,710	14,063
Equivalent (MMcfe)	1,449,146	1,392,742	449,020
Standardized measure of discounted future net cash flow after-tax, discounted at 10 percent (in thousands)	$ 2,200,889	$ 3,028,100	$ 798,033
Average price used in calculation of future net cash flow			
Gas ($/Mcf)	$ 5.54	$ 7.89	$ 5.58
Oil ($/Bbl)	$ 56.91	$ 57.65	$ 40.76

Significant Properties

As of December 31, 2006, 90 percent of proved reserves were located in the Mid-Continent, Permian Basin, Gulf Coast and Gulf of Mexico regions. In total we owned an interest in 13,194 gross (4,757 net) productive oil and gas wells.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2006.

	Oil (MBbl)	Gas (MMcf)	Equivalent (MMcfe)	Percent of Proved Reserves
Mid-Continent	8,709	542,447	594,701	41 %
Permian Basin	44,351	296,969	563,076	39 %
Gulf Coast	4,671	76,640	104,663	7 %
Gulf of Mexico	964	38,111	43,895	3 %
Western/Other	1,102	136,195	142,811	10 %
	59,797	1,090,362	1,449,146	100 %

Our ten largest fields hold 30 percent of our total equivalent proved reserves. We are the principal operator of our production in each of these fields (except Jo-Mill). The table below summarizes certain key statistics about these properties.

Field	Region	% of Total Proved Reserves	Avg. Working Interest	Avg. Depth (feet)	Primary Formation
Hugoton	Mid-Continent	4.3 %	59 %	2,600	Chase
Hemphill	Mid-Continent	4.1 %	95 %	11,000	Granite Wash
Panhandle East	Mid-Continent	3.5 %	98 %	2,400	Brown Dolomite
Eola-Robberson	Mid-Continent	3.2 %	95 %	5,500-11,000	Bromide/McLish/Oil Creek
Carlsbad South	Permian	2.8 %	58 %	11,500	Morrow/Atoka
Red Deer Creek	Mid-Continent	2.8 %	47 %	11,000	Granite Wash
Quail Ridge	Permian	2.6 %	59 %	13,000	Morrow
Jo-Mill	Permian	2.5 %	13 %	7,500	Spraberry
Mendota NW	Mid-Continent	2.3 %	71 %	11,000	Granite Wash
Westbrook	Permian	2.1 %	90 %	3,500	Clearfork
		30.2 %			

17

Acreage

The following table sets forth as of December 31, 2006, the gross and net acres of both developed and undeveloped leases held by Cimarex. Gross acres are the total number of acres in which we own a working interest. Net acres are the gross acres multiplied by our working interest.

	Undeveloped Acreage		Developed Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent						
Kansas	3,480	2,415	158,391	105,601	161,871	108,016
Oklahoma	103,772	85,182	395,645	168,255	499,417	253,437
Texas	144,826	106,218	232,402	110,785	377,228	217,003
	252,078	193,815	786,438	384,641	1,038,516	578,456
Permian Basin						
New Mexico	86,178	64,943	144,645	94,115	230,823	159,058
Texas	53,794	37,850	232,664	156,045	286,458	193,895
	139,972	102,793	377,309	250,160	517,281	352,953
Gulf Coast						
Louisiana	22,063	17,114	21,521	6,356	43,584	23,470
Texas	81,473	33,938	164,734	61,674	246,207	95,612
Mississippi	6,027	3,779	25,583	6,539	31,610	10,318
	109,563	54,831	211,838	74,569	321,401	129,400
Gulf of Mexico	711,140	438,125	324,614	110,709	1,035,754	548,834
Western/Other						
Arkansas			6,719	2,115	6,719	2,115
Arizona	914,695	914,695			914,695	914,695
California	35,715	30,678	8,770	6,752	44,485	37,430
Colorado	96,690	6,759	26,497	6,498	123,187	13,257
Illinois	1,782	1,191	554	183	2,336	1,374
Indiana	175	175	344	310	519	485
Michigan	31,803	31,686	549	549	32,352	32,235
Montana	49,449	16,298	18,858	7,735	68,307	24,033
Nebraska	4,560	116	2,118	168	6,678	284
Nevada	160	1	560	1	720	2
New Mexico	1,649,340	1,621,646	13,574	2,281	1,662,914	1,623,927
North Dakota	64,741	18,152	25,818	2,706	90,559	20,858
South Dakota	10,583	9,329	2,420	379	13,003	9,708
Utah	120,625	63,621	20,159	2,223	140,784	65,844
Wyoming	252,551	31,542	118,416	24,239	370,967	55,781
	3,232,869	2,745,889	245,356	56,139	3,478,225	2,802,028
	4,445,622	3,535,453	1,945,555	876,218	6,391,177	4,411,671

Gross Wells Drilled

We participated in drilling the following number of gross wells during calendar years 2006, 2005, and 2004:

	Exploratory			Developmental		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2006	20	32	52	490	16	506
Year ended December 31, 2005	55	20	75	283	24	307
Year ended December 31, 2004	12	11	23	177	21	198

We were in the process of drilling 30 gross (16 net) wells at December 31, 2006.

Net Wells Drilled

The number of net wells we drilled during calendar years 2006, 2005, and 2004 are shown below:

	Exploratory			Developmental		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2006	12.4	23.9	36.3	303.7	6.2	309.9
Year ended December 31, 2005	33.2	15.6	48.8	144.8	16.8	161.6
Year ended December 31, 2004	6.8	6.5	13.3	78.8	12.1	90.9

Productive Wells

We have working interests in the following productive wells as of December 31, 2006:

	Gas		Oil	
	Gross	**Net**	**Gross**	**Net**
Mid-Continent	3,396	1,721	1,017	529
Permian	1,023	557	6,109	1,629
Gulf Coast	525	138	186	91
Gulf of Mexico	124	27	38	6
Western/Other	144	24	632	35
	5,212	2,467	7,982	2,290

ITEM 3. LEGAL PROCEEDINGS

As of December 31, 2006, we have accrued $7.1 million for a mediated litigation settlement pertaining to post-production deductions on properties operated by Cimarex. We have also accrued an additional $1.5 million for a mediated litigation settlement pertaining to oil and gas property title issues. We anticipate payment of both settlements during 2007. Cimarex has other various litigation related matters in the normal course of business, none of which are material, individually or in aggregate.

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

No matters were submitted for a vote of security holders during the fourth quarter of 2006.

ITEM 4A. EXECUTIVE OFFICERS

The executive officers of Cimarex as of February 27, 2007 were:

Name	Age	Office
F.H. Merelli	70	Chairman of the Board, Chief Executive Officer, and President
Joseph R. Albi	48	Executive Vice President, Operations
Thomas E. Jorden	49	Executive Vice President, Exploration
Stephen P. Bell	52	Senior Vice President, Business Development and Land
Paul Korus	50	Vice President, Chief Financial Officer, and Treasurer
Gary R. Abbott	34	Vice President, Corporate Engineering
Richard S. Dinkins	62	Vice President, Human Resources
James H. Shonsey	55	Vice President, Chief Accounting Officer, and Controller

There are no family relationships by blood, marriage, or adoption among any of the above executive officers. All executive officers are elected annually by the board of directors to serve for one year or until a successor is elected and qualified. There is no arrangement or understanding between any of the officers and any other person pursuant to which he was selected as an executive officer.

F.H. MERELLI was elected chairman of the board, chief executive officer, and president on September 30, 2002. Prior to its merger with Cimarex, Mr. Merelli served as chairman and chief executive officer of Key Production Company, Inc. from September 1992 to September 2002. From June 1988 to July 1991 he was president and chief operating officer of Apache Corporation.

JOSEPH R. ALBI was named executive vice president of operations on March 1, 2005. Since December 8, 2003, Mr. Albi served as senior vice president of corporate engineering. From September 30, 2002 to December 8, 2003, Mr. Albi served as vice president of engineering. Prior to September 30, 2002, Mr. Albi was with Key Production Company, Inc. where he served as vice president of engineering (October 1999 to September 2002) and manager of engineering (June 1994 to October 1999).

THOMAS E. JORDEN was named executive vice president of exploration on December 8, 2003 and has served in a similar capacity since September 30, 2002. Prior to September 2002, Mr. Jorden was with Key Production Company, Inc., where he served as vice president of exploration (October 1999 to September 2002) and chief geophysicist (November 1993 to September 1999). Prior to joining Key, Mr. Jorden was with Union Pacific Resources.

STEPHEN P. BELL was elected senior vice president of business development and land on September 30, 2002. Prior to its merger with Cimarex, Mr. Bell had been with Key Production Company, Inc. since February 1994. In September 1999, he was appointed senior vice president, business development and land. From February 1994 to September 1999, he served as vice president, land.

PAUL KORUS was elected vice president, chief financial officer and treasurer on September 30, 2002. Mr. Korus was vice president and chief financial officer of Key Production Company, Inc. from September 1999 to September 2002. Prior to September 1999 and since June 1995, Mr. Korus was an equity research analyst with Petrie Parkman & Co., an investment banking firm.

GARY R. ABBOTT was elected vice president of corporate engineering on March 1, 2005. Since January 2002, Mr. Abbott served as manager, corporate reservoir engineering. From April 1999 to January 2002, Mr. Abbott was a reservoir engineer with Key Production Company, Inc.

RICHARD S. DINKINS was named vice president of human resources on December 8, 2003. Mr. Dinkins joined Key Production Company, Inc. in March 2002 as its director of human resources and continued in that position with Cimarex commencing in September 2002. Prior to joining Key and since February 1999, Mr. Dinkins was with Sprint.

JAMES H. SHONSEY was named vice president in April, 2006. Mr. Shonsey was elected chief accounting officer and controller on May 28, 2003. From 2001 to May 2003, Mr. Shonsey was chief financial officer of The Meridian Resource Corporation; and from 1997 to 2001, he served as the chief financial officer of Westport Resources Corporation.

PART II

ITEM 5. MARKET FOR THE REGISTRANT S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

Cimarex s $.01 par value common stock trades on the New York Stock Exchange under the symbol XEC. In December 2005, the Board of Directors declared the Company s first quarterly cash dividend of $.04 per share. A $.04 per share cash dividend was also declared to shareholders in every quarter of 2006. Future dividend payments will depend on the Company s level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

Stock Prices and Dividends by Quarters. The following table sets forth, for the periods indicated, the high and low sales price per share of Common Stock on the NYSE and the quarterly dividends paid per share.

2006	**High**	**Low**	**Dividends Per Share**
First Quarter	$ 47.80	$ 39.21	$ .04
Second Quarter	$ 47.40	$ 35.84	$ .04
Third Quarter	$ 43.03	$ 33.57	$ .04
Fourth Quarter	$ 38.46	$ 32.56	$ .04

2005	**High**	**Low**	**Dividends Per Share**
First Quarter	$ 42.56	$ 34.48	$ .00
Second Quarter	$ 40.55	$ 33.82	$ .00
Third Quarter	$ 45.98	$ 38.30	$ .00
Fourth Quarter	$ 46.31	$ 35.85	$ .00

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 15, 2007, was $36.10. At December 31, 2006, Cimarex s 82,883,310 shares of outstanding common stock were held by approximately 5,429 stockholders of record.

ITEM 5C. STOCK REPURCHASES.

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of common stock. Through December 31, 2005, 68,000 shares had been repurchased at an average price of $43.03. Since December 31, 2005 and through December 31, 2006, an additional 182,100 shares have been repurchased for an average price of $44.43 per share.

Period	**Total Number of Shares Purchased**	**Average Price Paid per Share**
December 1, 2005 to December 31, 2006	250,100	$ 44.05

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth below should be read in conjunction with the consolidated financial statements and accompanying notes thereto provided in **Item 8** of this Form 10-K.

	For the Years Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
Operating results:					
Revenues	$ 1,267,144	$ 1,118,622	$ 475,164	$ 325,621	$ 160,620
Net income	345,719	328,325	153,592	94,633	39,819
Basic earnings per share	4.21	5.07	3.70	2.28	1.32
Diluted earnings per share	4.11	4.90	3.59	2.22	1.31
Cash dividends declared per share	.16				
Balance sheet data:					
Total assets	4,829,750	4,180,335	1,105,446	805,508	674,286
Total debt	443,667	352,451			32,000
Stockholders equity	2,976,143	2,595,453	700,712	534,740	444,880
Other financial data:					
Oil and gas sales	1,215,411	1,072,422	472,389	324,119	157,299
Oil and gas capital expenditures	1,074,673	2,462,826	296,429	162,627	368,503
Proved Reserves:					
Gas (MMcf)	1,090,362	1,004,482	364,641	337,344	318,627
Oil (MBbls)	59,797	64,710	14,063	14,137	15,025
Total equivalent (MMcfe)	1,449,146	1,392,742	449,020	422,167	408,779

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

INTRODUCTION

Cimarex Energy Co. is an independent oil and gas exploration and production company, with operations focused mainly in Oklahoma, Texas, New Mexico, Kansas, Louisiana, and the Gulf of Mexico.

Our primary focus is exploration and development drilling for new reserves. To supplement our growth, we also consider mergers and acquisitions. On June 7, 2005, Cimarex acquired Magnum Hunter Resources, Inc, a Dallas-based independent oil and gas exploration and production company with operations concentrated in the Permian Basin of West Texas and New Mexico and in the Gulf of Mexico. Terms of the merger agreement provided that Magnum Hunter stockholders receive 0.415 shares of Cimarex common stock for each share of Magnum Hunter common stock. As a result of the merger, Cimarex issued 39.7 million common shares to Magnum Hunter s common stockholders and assumed $633 million of debt. The merger was accounted for as a purchase of Magnum Hunter by Cimarex. Results of operations from Magnum Hunter s properties are included in our consolidated statements of operations beginning June 7, 2005.

Our E&D expenditures totaled $1,049 million for 2006, up from $642 million in 2005. Operationally, we now have a large base of properties in the Permian Basin with operational characteristics similar to our Mid-Continent assets. The merger also extended our onshore Gulf Coast activities into the Gulf of Mexico. Overall, about 39 percent of our proved reserves are in the Permian Basin and 41 percent are in our Mid-Continent region. Our onshore Gulf Coast and Gulf of Mexico operations collectively make up 10 percent of our proved reserves.

Industry and Economic Factors

In managing our business we must deal with many factors inherent in our industry. First and foremost is wide fluctuation of oil and gas prices. Oil and gas markets are cyclical and volatile, with future price movements difficult to predict. While our revenues are a function of both production and prices, wide swings in prices often have the greatest impact on our results of operations.

Our operations entail significant complexities. Advanced technologies requiring highly trained personnel are utilized in both exploration and production. Even when the technology is properly used, the interpreter still may not know conclusively if hydrocarbons will be present or the rate at which they will be produced. Exploration is a high-risk activity, often times resulting in no commercially productive reservoirs being discovered. Moreover, costs associated with operating within the industry are substantial and usually move up and down together with prices.

The oil and gas industry is highly competitive. We compete with major and diversified energy companies, independent oil and gas companies, and individual operators. In addition, the industry as a whole competes with other businesses that supply energy to industrial, commercial, and residential end users.

Extensive federal, state, and local regulation of the industry significantly affects our operations. In particular, our activities are subject to comprehensive environmental regulations. Compliance with these regulations increases the cost of planning, designing, drilling, installing, operating, and abandoning oil and gas wells and related facilities. These regulations may become more demanding in the future.

Approach to the Business

Profitable growth largely depends upon our ability to successfully find and develop new proved reserves. To achieve an overall acceptable rate of growth, we maintain a blended portfolio of low, moderate, and higher risk exploration and development projects. We believe that this approach allows for consistent increases in our oil and gas reserves, while minimizing the chance of failure. To further mitigate risk, we have chosen to seek geologic and geographic diversification by operating in multiple basins. We may also consider the use of transaction-specific hedging of oil and gas prices to reduce price risk. In connection with the acquisition of Magnum Hunter, we acquired existing commodity derivatives, as well as in the third quarter of 2006 we entered into additional derivative contracts as discussed more fully below.

Implementation of our business approach relies on our ability to fund ongoing exploration and development projects with cash flow provided by operating activities, periodic sales of non-core properties, and external sources of capital.

We project that 2007 exploration and development expenditures will range from $800 million to $1 billion. Approximately 37 percent of the expenditures will be in the Mid-Continent area, 28 percent in the Permian Basin, 24 percent in the Gulf Coast area, and 8 percent in the Gulf of Mexico.

Cash flow from operating activities for 2006 totaled $878.4 million, which helped to fund our drilling program. Based on expected cash provided by operating activities and monies available under our Senior Secured Revolving Credit Facility, we believe we are well positioned to fund the projects identified for 2007 and beyond.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of our financial condition and results of operation are based upon Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 4 to our Consolidated Financial Statements included in this report. In response to SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure about Critical Accounting Policies, we have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates, including those related to oil and gas revenues, reserves and properties, as well as goodwill and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our Consolidated Financial Statements.

Revenue Recognition

Oil and Gas Sales

Revenue from the sale of oil and gas is recognized when title passes, net of royalties. This is known as the sales method (versus the entitlement method). Under the sales method, revenue is recognized on actual volumes sold to purchasers. There is a ready market for oil and gas, with sales occurring soon after production.

Marketing Sales

Cimarex markets and sells natural gas for working interest partners under short term sales and supply agreements and earns a fee for such services. Revenues are recognized as gas is delivered and are reflected net of gas purchases on the accompanying consolidated statement of operations.

Gas Imbalances

We use the sales method of accounting for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold. Oil and gas reserves are adjusted to the extent there are sufficient quantities of natural gas to make up an imbalance. In situations where there are insufficient reserves available to make-up an overproduced imbalance, then a liability is established. The natural gas imbalance liability at December 31, 2006 and 2005 was $3.2 million and $2.7 million, respectively. At December 31, 2006 we are also in an under-produced position relative to certain other third parties.

Oil and Gas Reserves

The process of estimating quantities of oil and gas reserves is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various fields make these estimates generally less precise than other estimates included in the financial statement disclosures. For 2006, revisions of reserve estimates equaled a decrease of 3.7 MBbls of oil and 14.5 Bcf of gas (due to lower oil and gas prices), representing two and one half percent of proved oil and gas reserves as of December 31, 2006. See Note 17, Supplemental Oil and Gas Disclosures for reserve data.

We use the units-of-production method to amortize our oil and gas properties. Changes in reserve quantities will cause corresponding changes in depletion expense in periods subsequent to the quantity revision or, in some cases, a full cost ceiling limitation charge in the period of the revision. To date, changes in expense resulting from changes in previous estimates of reserves have not been material.

Full Cost Accounting

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration, and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities, and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration, and development activities, are also capitalized.

At the end of each quarter, a full cost ceiling limitation calculation is made whereby net capitalized costs related to proved properties less associated deferred income taxes may not exceed an amount equal to the present value discounted at ten percent of estimated future net revenues from proved reserves less estimated future production and development costs and related income tax expense. Future net revenues used in the calculation of the full cost ceiling limitation are determined based on current oil and gas prices and is adjusted for designated cash flow hedges if it is determined that net capitalized costs exceed the full cost ceiling limit. If net capitalized costs subject to amortization were to exceed this limit, the excess would be charged to expense. However, if commodity prices increase subsequent to period end and prior to issuance of the financial statements, these higher commodity prices will be used to determine if the capital costs are in fact impaired as of the end of the period.

Goodwill

We account for goodwill in accordance with Statement of Financial Accounting Standard (SFAS) No. 142, *Goodwill and Other Intangible Assets*. SFAS No. 142 requires an annual impairment assessment. A more frequent assessment is required if certain events occur that reasonably indicate an impairment may have occurred. The volatility of oil and gas prices may cause more frequent assessments. The impairment assessment requires us to make estimates regarding the fair value of goodwill. The estimated fair value is based on numerous factors, including future net cash flows of our estimates of proved reserves as well as the success of future exploration for and development of unproved reserves. If the estimated fair value exceeds its carrying amount, goodwill is considered not impaired. If the carrying amount exceeds the estimated fair value, then a measurement of the loss must be performed, with any deficiency recorded as an impairment. To date, no related impairment has been recorded.

Derivatives

SFAS No.133, *Accounting for Derivative Instruments and Hedging activities,* requires that all derivatives be recorded on the balance sheet at fair value. We determine the fair value of derivative contracts based on the stated contract prices and current and projected market prices at the determination date discounted to reflect the time value of money until settlement. The accounting treatment for the changes in fair value is dependent upon whether or not a derivative instrument is designated as a hedge for accounting treatment purposes. Realized and unrealized gains and losses on derivatives that are not designated as hedges are recognized currently in costs and expenses associated with operating income in our consolidated statements of operations. For derivatives designated as cash flow hedges, changes in the fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is settled. Changes in the fair value of the hedge resulting from ineffectiveness are recognized currently as unrealized gains or losses in other income and expense in the consolidated statements of operations. Gains and losses upon settlement of the cash flow hedges will be recognized in gas revenues in the period the contracts are settled.

In connection with the Magnum Hunter merger, Cimarex recognized a $39.3 million net liability associated with Magnum Hunter s existing commodity derivatives at the merger date (June 7, 2005). These derivative instruments were not designated for hedge accounting treatment. As a result, Cimarex recognized a net gain for the year ended December 31, 2006 of $23 million. Activity included both non-cash mark-to-market derivative gains and losses as well as cash settlements. Cash payments related to these contracts that settled in the year ended December 31, 2006 was $19 million. As of December 31, 2006, all derivative contracts assumed with the Magnum Hunter merger had matured.

In the third quarter of 2006, we entered into additional derivative contracts to mitigate a portion of our potential exposure to adverse market changes in an environment of volatile gas prices. Using zero-cost collars with Mid-Continent weighted average floor and ceiling prices of $7.00 to $10.17 for 2007 and $7.00 to $9.90 for 2008, we hedged 29.2 million MMbtu and 14.6 million MMbtu of our anticipated Mid-Continent gas production for 2007 and 2008, respectively. At December 31, 2006, this represented approximately 51% and 31% of our current anticipated Mid-Continent gas production for 2007 and 2008, respectively.

Under the collar agreements, we will receive the difference between an agreed upon Mid-Continent index price and floor price if the index price is below the floor price. We will pay the difference between the agreed upon contracted ceiling price and the index price only if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices. These hedges have been designated for hedge accounting treatment as cash flow hedges.

For the year ended December 31, 2006, we recorded an unrealized loss of $13 thousand related to the ineffective portion of the hedges. At December 31, 2006, $41.9 million and $7.1 million of the hedges were recorded as current and long-term assets, respectively, and an unrealized gain (net of deferred income taxes) of $31 million was recorded in other comprehensive income. See Note 5 to the Consolidated Financial Statements and Item 7A of this report for additional information regarding our derivative instruments.

Depending on changes in oil and gas futures markets and management s view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current hedging positions.

Contingencies

A provision for contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes subjective judgment. In many cases, this judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. We closely monitor known and potential legal, environmental, and other contingencies and periodically determine when we should record losses for these items based on information available to us. As of December 31, 2006, we have accrued $7.1 million for a mediated litigation settlement pertaining to post-production deductions on properties operated by Cimarex. We have also accrued an additional $1.5 million for a mediated litigation settlement pertaining to oil and gas property title issues. We anticipate payment of both settlements during 2007. Cimarex has other various litigation related matters in the normal course of business, none of which that can be estimated are deemed to be material, individually or in aggregate. See Note 15 of Notes to Consolidated Financial Statements.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made, and the associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Subsequent to initial measurement, the asset retirement liability is required to be accreted each period. Capitalized costs are depleted as a component of the full cost pool.

Recent Accounting Developments

In July 2006, the FASB issued Interpretation 48, *Accounting for Uncertainty in Income Taxes,* which clarifies the accounting for uncertainty in income taxes recognized in the Company s financial statements in accordance with SFAS 109 Accounting for Income Taxes. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. Along with these disclosures, a tabular presentation of significant changes during each period will be required. The Interpretation is effective as of the beginning of the first fiscal year beginning after December 15, 2006 (January 1, 2007 for calendar-year companies). We are currently evaluating the effects of implementing this interpretation and do not believe the adoption of this interpretation will have a material impact on our financial statements.

In September 2006 the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108 regarding the process of quantifying misstatements within a financial statement, addressing in particular materiality analysis related to the correction of errors. The impact on the current year financial statements of correcting all misstatements, including both the carryover and reversing effects of prior year misstatements, must be quantified. Adjustment would be required if the misstatement is deemed material, after considering all relevant quantitative and qualitative factors. The periods in which the correction would be recorded would be dependent on the materiality considerations for each affected period. This did not have a material impact on our financial statements.

Also in September 2006 the Financial Accounting Standards Board issued Statement No. 157, *Fair Value Measurements,* which establishes a single authoritative definition of fair value, sets out a framework for measuring fair value, and requires additional disclosures about fair-value measurements. The Statement applies only to fair-value measurements that are already required or permitted by other accounting standards and is expected to increase the consistency of those measurements. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We do not expect the adoption of Statement No. 157 to have a material impact on our financial statements.

OVERVIEW

Our results of operations are primarily impacted by changes in oil and gas prices and changes in our production volumes. Realized gas prices decreased from $8.05 per Mcf in 2005 to $6.50 per Mcf in 2006, and oil prices increased from $55.25 per barrel in 2005 to $61.96 per barrel in 2006. Cimarex also sells gas on behalf of third parties that are incidental to sales of our own production. Sales and costs associated with our production are reflected in gas sales and transportation expense.

We also own interests in gas gathering systems and gas processing plants that are connected to our production operations. We transport and process third party gas that is associated with our gas.

Transportation expenses are comprised of costs paid to carry and deliver oil and gas to a specified delivery point. In some cases we receive a payment from purchasers which is net of transportation costs, and in other instances we separately pay for transportation. If costs are netted in the proceeds received, both the gross revenues and gross costs are shown in sales and expenses, respectively.

Production costs are composed of lease operating expenses, which generally consist of pumpers salaries, utilities, water disposal, maintenance and other costs necessary to operate our producing properties.

Taxes, other than income, are taxes assessed by state and local taxing authorities pertaining to production, revenues or the value of properties. These typically include production severance, ad valorem and excise taxes.

Depreciation, depletion and amortization of our producing properties is computed using the units-of-production method. Because the economic life of each producing well depends upon the assumed price for future sales of production, fluctuations in oil and gas prices may impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense, while lower prices generally have the effect of decreasing reserves, which increases depletion expense. In addition, changes in estimates of reserve quantities and estimates of future development costs or reclassifications from unproved properties to proved properties will impact depletion expense.

General and administrative expenses consist primarily of salaries and related benefits, office rent, legal fees, consultants, systems costs and other administrative costs incurred in our offices. While we expect such costs to increase with our growth, we expect such increases to be proportionately smaller than our production growth.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock and restricted stock units to certain employees and the expensing of stock options resulting from the adoption of SFAS No. 123R.

BASIS OF PRESENTATION

In June 2005, Cimarex acquired Magnum Hunter Resources, Inc, by issuing 0.415 shares of Cimarex common stock for each share of outstanding Magnum Hunter common stock, resulting in the issuance of 39.7 million Cimarex common shares. At December 31, 2005, Cimarex had 82.4 million shares outstanding. The merger was accounted for as a purchase of Magnum Hunter by Cimarex. The results of operations of Magnum Hunter were included in our consolidated statements of operations beginning June 7, 2005.

Certain amounts in prior years financial statements have been reclassified to conform to the 2006 financial statement presentation.

RESULTS OF OPERATIONS

Year Ended December 31, 2006 Compared with Year Ended December 31, 2005:

SUMMARY DATA:
(in thousands or as indicated)

	For the Years Ended December 31, 2006	2005
Net income	$ 345,719	$ 328,325
Per share basic	4.21	5.07
Per share diluted	4.11	4.90
Gas sales	$ 810,894	$ 807,007
Oil sales	404,517	265,415
Total oil and gas sales	$ 1,215,411	$ 1,072,422
Total gas volume Mcf	124,733	100,272
Gas volume MMcf per day	341.7	274.7
Average gas price per Mcf	$ 6.50	$ 8.05
Total oil volume thousand barrels	6,529	4,804
Oil volume barrels per day	17,887	13,162
Average oil price per barrel	$ 61.96	$ 55.25
Gas gathering and processing revenues	$ 47,879	$ 44,238
Gas gathering and processing costs	(27,410)	(31,890)
Gas gathering and processing margin	$ 20,469	$ 12,348
Gas marketing revenues, net of related costs	$ 3,854	$ 1,962
Expenses and other income:		
Depreciation, depletion and amortization	$ 396,394	$ 258,287
Production	176,833	104,067
Transportation	21,157	15,338
Taxes other than income	91,066	73,360
General and administrative	42,288	33,497
Stock compensation	8,243	4,959
Other operating, net	2,064	15,897
(Gain) Loss on derivative instruments	(22,970)	67,800
Int. exp., net of cap. int. & amort. of F.V. of debt	1,908	5,789
Asset retirement obligation accretion	7,018	3,819
Other, net	(28,591)	(12,536)

Net income for the year of 2006 was $345.7 million, or $4.11 per diluted share, compared to net income of $328.3 million, or $4.90 per diluted share in 2005. The change in net income results from the effect of changes in revenues and costs, as discussed further. The results of operations of Magnum Hunter are included in our consolidated statements of operations only for the period since the acquisition on June 7, 2005.

Oil and gas sales for the year of 2006 totaled $1.2 billion, compared to $1.1 billion for 2005. The $143.0 million increase in sales between the two periods results from $292.0 million related to higher production volumes, offset by a decrease of $149.0 million resulting from lower commodity prices.

Sales benefited from higher production volumes. Average daily gas production rose 67.0 MMcf in 2006 to 341.7 MMcf from 274.7 MMcf in 2005, resulting in $197.0 million of incremental revenues. Oil volumes averaged 17,887 barrels per day for 2006, compared to 13,162 barrels per day in 2005, resulting in increased revenues of $95.0 million. The increase in sales volumes between the periods of 2006 and 2005 is due to the inclusion of Magnum Hunter operations beginning June 7, 2005 (date of acquisition) and positive drilling results during 2005 and 2006. Production volumes in the Gulf of Mexico and along the Texas and Louisiana Gulf Coast area were negatively impacted during the fourth quarter of 2005 as a result of hurricanes. It is estimated to have negatively impacted fourth-quarter 2005 production by 41 to 45 MMcf equivalent per day. These volumes were brought back online throughout 2006, and by the fourth quarter of 2006 less than one MMcf equivalent per day was shut-in from the 2005 hurricane activity. No oil and gas reserves have been lost as a result of the storms and the majority of associated repair costs will be covered by insurance.

Realized gas prices averaged $6.50 per Mcf for 2006, compared to $8.05 per Mcf for 2005. This 19 percent change decreased sales by $193.0 million between the two periods. Realized oil prices, however, averaged $61.96 per barrel for 2006, compared to $55.25 per barrel for 2005. The increase in sales between periods resulting from this 12 percent improvement in oil prices totaled $44.0 million. Changes in realized prices were the direct result of overall market conditions.

Gas gathering and processing revenues, net of related costs, equaled $20.5 million in 2006, compared to $12.4 million in 2005. The increase is due to the inclusion of related activities from Magnum Hunter operations from June 7, 2005. We own interests in gas gathering systems and gas processing plants that are connected to our production operations. We transport and process third party gas that is associated with our gas.

Gas marketing net revenues increased to $3.9 million from $2 million, net of related costs of $144.7 million and $213.7 million for 2006 and 2005, respectively. Gas marketing revenues, net of related costs, pertain to sales of gas on behalf of third parties that is incidental to sales of our own production.

Costs and Expenses

Net costs and expenses (not including gas gathering, marketing and processing costs, as well as income tax expense) were $695.4 million in 2006 compared to $570.3 million in 2005. Depreciation, depletion and amortization (DD&A) was the largest component of the increase between periods. DD&A equaled $396.4 million in 2006 compared to $258.3 million in 2005. On a unit of production basis, DD&A was $2.42 per Mcfe in 2006 compared to $2.00 per Mcfe for 2005. The increase stems from higher costs for reserves added during 2005 and 2006. Service costs to drill and complete wells have been increasing. That along with certain high cost dry holes in our Gulf Coast and Gulf of Mexico regions have influenced our per unit rates, even though overall drilling success rates have remained high.

Production costs rose $72.7 million from $104.1 million ($.81 per Mcfe) in 2005 to $176.8 million ($1.08 per Mcfe) in 2006. The higher costs in 2006 resulted from higher field operating expenses from an expanded number and type of properties, higher maintenance costs and increased insurance costs due to past hurricanes. Additional workover/maintenance projects were implemented in 2006, totaling $28.9 million ($0.18 per Mcfe) compared to $11.6 million ($0.09 per Mcfe) in 2005.

Transportation costs increased from $15.3 million in 2005 to $21.2 million in 2006. The increase is the result of higher sales volumes and that expiring contracts are being renewed with increased current market rates.

Taxes other than income were $17.7 million greater, rising from $73.4 million in 2005 to $91.1 million in 2006. The increase between periods resulted from increases in oil and gas sales stemming from higher production volumes and oil prices.

General and administrative (G&A) expenses increased $8.8 million from $33.5 million in 2005 to $42.3 million in 2006. The increase between periods is due to an expansion of staff and higher employee-benefit costs.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units and stock option awards. Stock compensation increased from $5.0 million in 2005 to $8.2 million in 2006.

Other operating, net decreased from $15.9 million in 2005 to $2.1 million in 2006. These expenses in 2005 consisted primarily of $9.4 million of costs associated with the Magnum Hunter merger. Of this $9.4 million, $3.6 million is due to the acceleration of vesting of stock options and restricted stock units resulting from change of control provisions under our stock incentive plan becoming effective due to the Magnum Hunter merger. The remaining $5.8 million consists of $4.3 million of general integration costs, $1.0 million for retention bonuses, and $0.5 million of related financing costs. In addition to merger costs, 2005 expenses also included a mediated $6.5 million litigation settlement pertaining to post-production deductions on properties operated by Cimarex. Other expense for 2006 included $2.1 million of litigation settlements pertaining primarily to resolution of oil and gas property title issues.

Another component of net costs and expenses for 2006 and 2005 was the gain and loss on derivative instruments. In connection with the Magnum Hunter merger, Cimarex recognized a $39.3 million liability associated with Magnum Hunter s existing commodity derivatives at the merger date (June 7, 2005). These derivative instruments were not designated for hedge accounting treatment. As a result, Cimarex recognized net gains for the year 2006 of $23.0 million and net losses for 2005 of $67.8 million, respectively. Activity includes both non-cash mark-to-market derivative gains and losses as well as cash settlements. Cash payments related to these contracts that settled in 2006 and 2005 totaled $19.0 million and $64.3 million, respectively. Theses contracts expired December 31, 2006.

To mitigate a portion of the potential exposure to adverse market changes in an environment of volatile gas prices, we entered into additional derivative contracts in third quarter of 2006. These derivatives have been designated for hedge accounting treatment as cash flow hedges. Changes in the fair value of the hedges, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is settled. Changes in the fair value of the hedge resulting from ineffectiveness are recognized currently as unrealized gains or losses in other income and expense in the consolidated statements of operations. Gains and losses upon settlement of the cash flow hedges will be recognized in gas revenues in the period the contracts are settled. During 2006, we recognized an unrealized loss of $13 thousand related to the ineffective portion of the derivative contracts.

Net interest expense in 2006 totaled $1.9 million, comprised of $29.9 million of interest expense, offset by $24.2 million of capitalized interest and $3.8 million of amortization of fair value of debt. We capitalize interest related to borrowings associated with costs incurred to bring properties under development, not being amortized, to their intended use. This has decreased from $5.8 million of net interest expense in 2005, which was comprised of $19.6 million of interest expense, offset by $11.7 million of capitalized interest and $2.1 million of amortization of fair value of debt. The increases in the components of the 2006 net interest amount results from amounts associated with the debt assumed in the Magnum Hunter merger and an increase in costs incurred to bring properties under development, not being amortized, to their intended use. Prior to the Magnum Hunter merger, Cimarex had no outstanding debt.

Asset retirement obligation accretion increased $3.2 million from $3.8 million in 2005 to $7.0 million in 2006. The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made, and the associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Since 2005 the liability has increased $28.0 million from $101.1 million in 2005 to $129.1 million in 2006.

Other, net increased from $12.5 million of income in 2005 to $28.6 million of income in 2006. The components of this other income net of other expenses consist of miscellaneous items that will vary from period to period, including income and loss in equity investees. The large increase from 2005 to 2006 is due primarily to distribution received in excess of our investment in the Company s limited partnership affiliates, Teal Hunter L.P. and Mallard Hunter L.P. These partnerships sold all of their interest in oil and gas properties during 2006. Cimarex s investments in these partnerships had been reflected in other assets, net. Net sales consideration received via distributions from the partnerships equaled $59.3 million, which are in excess of the Company s investment balance in the partnerships. The excess distributions of $19.8 million have been recorded in other income for 2006.

Income tax expense

Income tax expense totaled $198.6 million for 2006 versus $188.1 million for 2005. Tax expense equaled a combined federal and state effective income tax rate of 36.5 percent and 36.4 percent in 2006 and 2005, respectively. Included in the 2006 income tax expense of $198.6 million is a current benefit of $21.9 million.

Year Ended December 31, 2005 Compared with Year Ended December 31, 2004:

SUMMARY DATA:
(in thousands or as indicated)

	For the Years Ended December 31, 2005	2004
Net income	$ 328,325	$ 153,592
Per share basic	5.07	3.70
Per share diluted	4.90	3.59
Gas sales	$ 807,007	$ 366,260
Oil sales	265,415	106,129
Total oil and gas sales	$ 1,072,422	$ 472,389
Total gas volume MMcf	100,272	63,611
Gas volume MMcf per day	274.7	173.8
Average gas price per Mcf	$ 8.05	$ 5.76
Total oil volume thousand barrels	4,804	2,641
Oil volume barrels per day	13,162	7,215
Average oil price per barrel	$ 55.25	$ 40.19
Gas gathering and processing revenues	$ 44,238	$ 101
Gas gathering and processing costs	(31,890)	(284)
Gas gathering and processing margin	$ 12,348	$ (183)
Gas marketing revenues, net of related costs	$ 1,962	$ 2,674
Costs and expenses:		
Depreciation, depletion and amortization	$ 258,287	$ 124,251
Production	104,067	37,476
Transportation	15,338	10,003
Taxes other than income	73,360	37,761
General and administrative	33,497	22,483
Stock compensation	4,959	1,957
Other operating, net	15,897	(3,394)
Loss on derivative instruments	67,800	
Int. exp., net of cap. int. & amort. of F.V. of debt	5,789	1,075
Asset retirement obligation accretion	3,819	1,241
Other, net	(12,536)	(4,291)

Net income for the year of 2005 was $328.3 million, or $4.90 per diluted share, compared to net income of $153.6 million, or $3.59 per diluted share in 2004. The change in net income results from the effect of changes in revenues and costs, as discussed further. The results of operations of Magnum Hunter are included in our consolidated statements of operations only for the period since the acquisition on June 7, 2005.

Oil and gas sales for the year of 2005 totaled $1.1 billion, compared to $472.4 million for 2004. The $600.0 million increase in sales between the two periods results from $302.0 million related to higher commodity prices and $298.0 million due to higher production volumes (due primarily to increased production resulting from the acquisition of Magnum Hunter).

Realized gas prices averaged $8.05 per Mcf for 2005, compared to $5.76 per Mcf for 2004. This 40 percent change increased sales by $230.0 million between the two periods. Realized oil prices averaged

$55.25 per barrel for 2005, compared to $40.19 per barrel for 2004. The increase in sales between periods resulting from this 37 percent improvement in oil prices totaled $72.0 million. Changes in realized prices were the direct result of overall market conditions.

Sales also benefited from higher production volumes. Average gas volumes rose 100.9 MMcf per day in 2005 to 274.7 MMcf per day from 173.8 MMcf per day in 2004, resulting in $211.1 million of incremental revenues. Oil volumes averaged 13,162 barrels per day for 2005, compared to 7,215 barrels per day in 2004, resulting in increased revenues of $86.9 million. The increase in sales volumes between the periods of 2005 and 2004 is due to positive drilling results during 2004 and 2005, and the inclusion of production from Magnum Hunter operations from June 7, 2005. Production volumes in the Gulf of Mexico and along the Texas and Louisiana Gulf Coast area were negatively impacted during the third and fourth quarters of 2005 as a result of hurricanes. It is estimated to have negatively impacted fourth-quarter 2005 production by 41 to 45 MMcf equivalent per day and full-year volumes by 17 to 20 MMcf equivalent per day. At year-end 2005, approximately 20 MMcf equivalent was still shut-in. It is anticipated that most of the remaining shut-in volumes will be restored by the end of the first quarter of 2006. The timetable to restore full production largely depends on the startup of refineries, gas processing plants, platforms, facilities and pipelines owned and operated by others. No oil and gas reserves have been lost as a result of the storms and essentially all associated repair costs will be covered by insurance.

Gas gathering and processing revenues, net of related costs, equaled $12.4 million in 2005, compared to a loss of $0.2 million in 2004. The increase is due to the inclusion of related activities from Magnum Hunter operations from June 7, 2005. We own interests in gas gathering systems and gas processing plants that are connected to our production operations. We transport and process third party gas that is associated with our gas.

Gas marketing net revenues decreased to $2 million from $2.7 million, net of related costs of $213.7 million and $193.0 million for 2005 and 2004, respectively. Gas marketing revenues, net of related costs, pertain to sales of gas on behalf of third parties that is incidental to sales of our own production.

Costs and Expenses

Costs and expenses (not including gas gathering, marketing and processing costs as well as income tax expense) were $570.3 million in 2005 compared to $228.6 million in 2004. Depreciation, depletion and amortization (DD&A) was the largest component of the increase between periods. DD&A equaled $258.3 million in 2005 compared to $124.3 million in 2004. On a unit of production basis, DD&A was $2.00 per Mcfe in 2005 compared to $1.56 per Mcfe for 2004. The increase largely stems from costs associated with Magnum Hunter operations and higher costs for reserves added during 2004 and 2005.

Production costs rose $66.6 million from $37.5 million ($.47 per Mcfe) in 2004 to $104.1 million ($.81 per Mcfe) in 2005 The higher costs in 2005 resulted primarily from the inclusion of costs associated with Magnum Hunter operations, higher field operating expenses from an expanded number of properties and higher maintenance costs.

Transportation costs increased from $10.0 million in 2004 to $15.3 million in 2005. The increase is the result of expiring contracts being renewed with increased current market rates and the inclusion of transportation costs associated with Magnum Hunter operations.

Taxes other than income were $35.6 million greater, rising from $37.8 million in 2004 to $73.4 million in 2005. The increase between periods resulted from increases in oil and gas sales stemming from inclusion of Magnum Hunter operations, higher production volumes and commodity prices.

General and administrative (G&A) expenses increased $11.0 million from $22.5 million in 2004 to $33.5 million in 2005. The increase between periods is due to an expansion of staff and higher employee-benefit costs.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units and stock option awards. Stock compensation increased from $2.0 million in 2004 to $5.0 million in 2005 due primarily to the $3.4 million expensing of stock options resulting from the adoption of SFAS No. 123R as of January 1, 2005.

Other operating, net totaled an expense of $15.9 million in 2005 and income of $3.4 million in 2004. The 2005 expenses consisted primarily of $9.4 million of costs associated with the Magnum Hunter merger. Of this $9.4 million, $3.6 million is due to the acceleration of vesting of stock options and restricted stock units resulting from change of control provisions under our stock incentive plan becoming effective due to the Magnum Hunter merger. The remaining $5.8 million consisted of $4.3 million of general integration costs, $1.0 million for retention bonuses, and $0.5 million of related financing costs. In addition to merger costs, 2005 expenses also included a mediated $6.5 million litigation settlement pertaining to post-production deductions on properties operated by Cimarex. The income reflected in 2004 consisted of miscellaneous litigation settlements in favor of the Company.

Another large component of the increase in costs and expenses between periods was the loss on derivative instruments. Prior to the acquisition of Magnum Hunter, Cimarex did not use financial instruments to mitigate commodity price changes. In connection with the merger, we recognized a $39.3 million liability associated with Magnum Hunter s existing commodity derivatives at the merger date (June 7, 2005). These derivative instruments have not been designated for hedge accounting treatment. As a result, Cimarex recognized in earnings during 2005 a net loss of $67.8 million. The charge includes both non-cash mark-to-market derivative losses as well as cash settlements. Cash payments related to these contracts that settled in 2005 totaled $64.3 million. The net derivative liability at December 31, 2005 equals $41.9 million. Cimarex will continue to recognize mark-to-market gains and losses as well as amortization of these contracts in future earnings until the derivative instruments mature.

Net interest expense in 2005 of $5.8 million is comprised of $19.6 million of interest expense, offset by $11.7 million of capitalized interest resulting from interest recognized on borrowings associated with costs incurred to bring properties under development, not being amortized, to their intended use and $2.1 million of amortization of fair value of debt. This has increased from $1.1 million of interest expense in 2004. The additional components of the 2005 net interest amount and the increase from 2004 results from amounts associated with the debt assumed in the Magnum Hunter merger. Prior to the Magnum Hunter merger, Cimarex had no outstanding debt.

Asset retirement obligation accretion increased $2.6 million from $1.2 million in 2004 to $3.8 million in 2005. The Company recognizes the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made, and the associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Oil and gas producing companies incur this liability which includes costs related to the plugging of wells, the removal of facilities and equipment, and site restorations, upon acquiring or drilling a successful well. Since 2004 the liability has increased $81.3 million from $19.8 million in 2004 to 101.1 million in 2005.

Other, net increased from $4.3 million of income in 2004 to $12.5 million of income in 2005. The components of this other income net of other expenses consist of miscellaneous items that will vary from period to period. The increase from 2004 to 2005 is due primarily to additional gains on the sale of miscellaneous equipment inventory.

Income tax expense

Income tax expense totaled $188.1 million for 2005 versus $92.7 million for 2004. Tax expense equaled a combined federal and state effective income tax rate of 36.4 percent and 37.6 percent in 2005 and 2004, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

Our primary source of capital is cash flow generated from operating activities. Prices we receive for oil and gas sales and our level of production will impact these future cash flows. No prediction can be made as to the prices we will receive. Production volumes will in large part be dependent upon the amount and results of future capital expenditures. In turn, actual levels of capital expenditures may vary due to many factors, including drilling results, oil and gas prices, industry conditions, prices and availability of goods and services, and the extent to which proved properties are acquired.

Cash flow provided by operating activities for 2006 was $878.4 million, compared to $704.7 million for 2005. The increase in 2006 from the earlier period resulted primarily from higher oil and gas production and higher oil prices.

Cash flow used in investing activities for 2006 was $1.0 billion, compared to $497.5 million for 2005. The increase in 2006 stemmed from a larger exploration and development program.

Cash flow provided by financing activities in 2006 was $74.8 million versus $261.4 million used in 2005. The cash provided by financing activities in 2006 resulted primarily from the borrowing of $95.0 million on our credit facility.

Financial Condition

As of December 31, 2006, stockholders equity totaled $3.0 billion, up from $2.6 billion at December 31, 2005. The increase resulted primarily from 2006 net income of $345.7 million. At December 31, 2006 our cash balance equaled $5.0 million.

In December 2005, the Board of Directors declared the Company s first quarterly cash dividend of $.04 per share payable to shareholders. A $.04 per share dividend has been authorized in every quarter of 2006. Also in December 2005, the Board of Directors authorized the repurchase of up to four million shares of common stock. Through December 31, 2005, 68,000 shares had been repurchased at an average price of $43.03. Since December 31, 2005 and through December 31, 2006, an additional 182,100 shares have been repurchased for an average price of $44.43 per share.

Working Capital

Working capital at December 31, 2006 totaled $62.2 million, compared to $31.6 million at December 31, 2005. The increase is primarily the result of settlement of the liability associated with derivative contracts outstanding at December 31, 2005 and entering into new derivative contracts in the third quarter for which a current asset was recorded at December 31, 2006.

Our receivables are a major component of our working capital and are made up of a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. The collection of receivables during the period presented has been timely. Historically, losses associated with uncollectible receivables have not been significant.

Financing

Debt at December 31, 2005 consisted of the following (in thousands):

Bank debt	$	
9.6% Notes due 2012 (face value $195,000)	213,770	(1)
Floating rate convertible notes due 2023 (face value $125,000)	138,681	(2)
Total long-term debt	$ 352,451	

Debt at December 31, 2006 consisted of the following (in thousands):

Bank debt	$ 95,000	
9.6% Notes due 2012 (face value $195,000)	210,746	(1)
Floating rate convertible notes due 2023, 5.36% at December 31, 2006 (face value $125,000)	137,921	(2)
Total long-term debt	$ 443,667	

(1) Fair market value at June 7, 2005 (date of acquisition of Magnum Hunter) equaled $215.5 million. The subsequent noted balances represent the fair market value at date of acquisition less amortization of the premium of fair market value over face value.

(2) Fair market value at June 7, 2005 equaled $144.75 million. The subsequent noted balances represent the fair market value at date of acquisition less amortization of the premium of fair market value over face value.

Cimarex s Revolving Credit Facility provides for $500 million of long-term committed credit. The facility is scheduled to mature on July 1, 2010 and is secured by mortgages on certain oil and gas properties and the stock of certain wholly-owned operating subsidiaries. At December 31, 2006, there were outstanding borrowings of $95 million under the Revolving Credit Facility at a weighted average interest rate of approximately 6.75%. We also had outstanding letters of credit of approximately $5 million, leaving an unused borrowing capacity of approximately $400 million at December 31, 2006.

The Credit Facility agreement contains both financial and non-financial covenants. Cimarex continues to comply with these covenants and does not view them as materially restrictive.

The 9.6% notes assumed in the Magnum Hunter merger have a face value of $195 million and are due March 15, 2012. The notes are unsecured and are redeemable, as a whole or in part, at Cimarex s option, on and after March 15, 2007 at the following redemption prices (expressed as percentages of the principal amount), plus accrued interest, if any, thereon to the date of redemption.

Year	**Percentage**
2007	104.8 %
2008	103.2 %
2009	101.6 %
2010 and thereafter	100.0 %

The floating rate convertible senior notes were assumed in the Magnum Hunter merger and mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at an annual rate equal to three-month LIBOR, reset quarterly. On December 31, 2006, the interest rate equaled 5.36%.

37

Holders of the convertible notes may surrender their notes for conversion into a combination of cash and shares of our common stock upon the occurrence of certain circumstances, including if the price of our common stock has been trading above the fixed conversion price of $28.99 per share. On December 29, 2006, the closing price of our common stock traded on the New York Stock Exchange was $36.50. There is not an observable market for the notes. Based on an average common stock price of $36.50, management estimates the fair value of the notes at December 31, 2006 was approximately $157.4 million (or $1,259 per bond).

In addition to the holders right to redeem the notes if our common stock price is above the conversion price, the holders also have the right to require Cimarex to repurchase all or a portion of the notes at a repurchase price equal to 100% of the principal amount (plus accrued interest) on December 15, 2008, 2013, and 2018. The indenture agreement also provides Cimarex with an option to redeem some or all of the notes at a redemption price equal to 100% of the principal amount (plus accrued interest) anytime after December 22, 2008.

Contractual Obligations and Material Commitments

At December 31, 2006, we had contractual obligations and material commitments as follows:

	Payments Due by Period				
Contractual obligations	**Total** (In thousands)	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**
Long-term debt(1)	$ 415,000	$	$	$ 95,000	$ 320,000
Fixed-Rate interest payments(1)	102,960	18,720	37,440	37,440	9,360
Operating leases	31,278	5,158	10,074	7,868	8,178
Drilling commitments	55,322	55,322			
Asset retirement obligation(2)	129,141	4,320			
Other liabilities	5,932	202	67	51	5,612

(1) These amounts do not include interest on the $95 million of bank debt outstanding at December 31, 2006. The weighted average interest rate at December 31, 2006 on the bank debt was approximately 6.75%. See item 7A: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) We have excluded the long term asset retirement obligations because we are not able to precisely predict the timing of these amounts.

At December 31, 2006, we had a firm sales contract to deliver approximately four Bcf of natural gas over the next eight months. If this gas is not delivered, our financial commitment would be approximately $22.3 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our reserves and current production levels.

Cimarex has other various delivery commitments in the normal course of business, none of which are individually material. In aggregate these commitments have a maximum amount that would be payable, if no gas is delivered, of approximately $2.8 million.

All of the commitments were routine and were made in the normal course of our business.

Based on current commodity prices and anticipated levels of production, we believe that the estimated net cash generated from operations, coupled with the cash on hand and amounts available under our existing line of credit will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

2007 Outlook

Our projected 2007 exploration and development expenditure program ranging from $800 million to $1 billion will require a great deal of coordination and effort. Though there are a variety of factors that could curtail, delay or even cancel some of our drilling operations, we believe our projected program has a high degree of occurrence. The majority of projects are in hand, drilling rigs are being scheduled, and the historical results of our drilling efforts in these areas warrant pursuit of the projects.

Costs of operations on a per Mcfe basis for 2007 are estimated to approximate levels realized in late 2006. Should factors beyond our control change, our program and realized costs will vary from current projections. These factors could include volatility in commodity prices, changes in the supply of and demand for oil and gas, weather conditions, governmental regulations and more.

Production estimates for 2007 range from 450 to 470 MMcfe per day. Revenues will be dependent not only on the level of oil and gas actually produced, but also the prices that will be realized. During 2006, our realized prices averaged $6.50 per Mcf of gas and $61.96 per barrel of oil. Prices can be very volatile and the possibility of 2007 realized prices being different than they were in 2006 is high.

ITEM 7A. Qualitative and Quantitative Disclosures about Market Risk

Price Fluctuations

Our results of operations are highly dependent upon the prices we receive for oil and gas production, and those prices are constantly changing in response to market forces. Nearly all of our revenue is from the sale of oil and gas, so these fluctuations, positive and negative, can have a significant impact on our results of operations and cash flows.

Monthly gas price realizations during 2006 ranged from $4.23 per Mcf to $8.43 per Mcf. Oil prices ranged from $54.85 per barrel to $70.61 per barrel. It is impossible to predict future oil and gas prices with any degree of certainty.

In third quarter 2006, we entered into derivative contracts to mitigate a portion of our potential exposure to adverse market changes in the Mid-Continent region, in an environment of volatile gas prices. These arrangements, which were based on prices available in the financial markets at the time the contracts were entered into, will be settled in cash and will not require physical delivery of hydrocarbons. These hedges have been designated for hedge accounting treatment as cash flow hedges under SFAS No. 133 and therefore, gains and losses upon settlement of the hedges will be recognized in gas revenue in the period the contracts are settled. We believe that we have sufficient production volumes such that the hedge contract transactions will occur as expected.

The following tables reflect the volumes, weighted average contract prices and fair values of the contracts we have in place as of December 31, 2006. We are exposed to risks associated with these contracts arising from volatility in commodity prices and the unlikely event of non-performance by the counterparties to the agreements. See Note 5 to the Consolidated Financial Statements and *Derivative Instruments* in Item 7 of this report for additional information regarding our derivative instruments.

Commodity	**Type**	**Volume/Day**	**Duration**	**Mid-Continent Weighted Average Price**	**Fair Value (000 s)**
Natural Gas	Collars	80,000 MMBTU	Jan 07 Dec 07	$ 7.00 - $10.17	$ 41,945
Natural Gas	Collars	40,000 MMBTU	Jan 08 Dec 08	$ 7.00 - $9.90	7,051
					$ 48,996

39

At December 31, 2006, the weighted average Mid-Continent prices for the 2007 and 2008 contracts approximated $6.13 and $7.02, respectively.

Interest Rate Risk

Fixed and Variable Rate Debt. Cimarex assumed fixed and variable rate debt as part of the acquisition of Magnum Hunter. These agreements expose the company to market risk related to changes in interest rates. The company has a credit facility that bears interest at either a Base rate or a Eurodollar rate at the Company s option.

The following table presents the carrying and fair value of the company s debt along with average interest rates as of December 31, 2006. The fair value for the Convertible Notes was based on an average price per share of $36.50 for Cimarex common stock. The fair value for the fixed rate Senior Notes was valued at their last traded value before December 31, 2006.

Expected Maturity Dates	2010	2012	2023	Total	Book Value	Fair Value
	(in thousands of dollars)					
Variable Rate Debt:						
Bank debt(a)	$ 95,000	$	$	$ 95,000	$ 95,000	$ 95,000
Convertible Notes(b)	$	$	$ 125,000	$ 125,000	$ 137,921	$ 157,393
Fixed Rate Debt:						
Senior Notes(c)	$	$ 195,000	$	$ 195,000	$ 210,746	$ 205,238

(a) At December 31, 2006, the weighted average interest rate on outstanding borrowings under the credit facility was approximately 6.75%.

(b) The interest rate on the convertible notes is 5.36%. The rate on these notes is equal to the three month LIBOR, adjusted quarterly. A holder of these notes has the right to require us to repurchase all or a portion of these notes on December 15, 2008, 2013, and 2018. The repurchase will be equal to the face value of the notes plus accrued and unpaid interest up to the date of repurchase. Included in Paid in Capital is $49.6 million related to the fair value of common stock associated with the convertible debt.

(c) The interest rate on the senior notes due 2012 is a fixed 9.6%.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CIMAREX ENERGY CO.

INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES

All other supplemental information and schedules have been omitted because they are not applicable or the information required is shown in the consolidated financial statements or related notes thereto.

Report of Independent Registered Public Accounting Firm

The Board of Directors
Cimarex Energy Co.:

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity and comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2006. 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 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 financial position of Cimarex Energy Co. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of the Sponsoring Organizations of the Treadway Commission, and our report dated February 27, 2007 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

As discussed in Note 4 to the Consolidated Financial Statements, Cimarex Energy Co. adopted Statement of Financial Accounting Standards No. 123(R), Share Based Payment, as of January 1, 2005.

KPMG LLP

Denver, Colorado

February 27, 2007

CIMAREX ENERGY CO.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share information)

	December 31, 2006	2005
Assets		
Current assets:		
Cash and cash equivalents	$ 5,048	$ 61,647
Accounts receivable:		
Trade, net of allowance	62,866	66,723
Oil and gas sales, net of allowance	189,906	191,748
Gas gathering, processing, and marketing, net of allowance	8,083	30,471
Other	45,603	242
Inventories	39,397	34,784
Deferred income taxes	1,498	17,959
Derivative instruments	41,945	
Other current assets	22,411	25,454
Total current assets	416,757	429,028
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	4,656,854	3,602,797
Unproved properties and properties under development, not being amortized	425,173	388,839
	5,082,027	3,991,636
Less accumulated depreciation, depletion and amortization	(1,494,317)	(1,114,677)
Net oil and gas properties	3,587,710	2,876,959
Fixed assets, less accumulated depreciation of $33,273 and $17,171	88,924	86,916
Goodwill	691,432	717,391
Derivative instruments	7,051	
Other assets, net	37,876	70,041
	$ 4,829,750	$ 4,180,335
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 40,735	$ 50,529
Gas gathering, processing, and marketing	15,506	31,418
Accrued liabilities:		
Exploration and development	94,403	76,725
Taxes other than income	25,376	15,978
Other	82,384	86,373
Derivative instruments		41,926
Revenue payable		