CIMAREX ENERGY CO
Form 10-K
February 26, 2010

Use these links to rapidly review the document

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D C 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009

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 ý 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 ý

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 ý NO o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ý 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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Aggregate market value of the voting stock held by non-affiliates of Cimarex Energy Co. as of June 30, 2009 was approximately $2,319,938,473.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 19, 2010 was 83,839,327.

Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2010 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

Table of Contents

TABLE OF CONTENTS

DESCRIPTION

Table of Contents

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

Table of Contents

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.

4

Table of Contents

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, Kansas and Wyoming. Proved oil and gas reserves as of year-end 2009 totaled 1.5 Tcfe, consisting of 1.2 Tcf of gas and 58.0 million barrels of oil and natural gas liquids. Of total proved reserves, 77 percent are gas and 77 percent are classified as proved developed. Our 2009 production averaged 462.9 MMcfe per day, comprised of 323.2 MMcf of gas per day and 23,283 barrels of oil per day. We operate the wells that account for 79 percent of our total proved reserves and approximately 82 percent of 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. Cimarex is a Delaware corporation.

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 Securities and Exchange Commission ("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. Throughout this Form 10-K we use the terms "Cimarex," "Company," "we," "our," and "us" to refer to Cimarex Energy Co. and its subsidiaries.

History

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, we acquired Dallas-based Magnum Hunter Resources, Inc. in a $1.5 billion stock-for-stock merger including assumption of liabilities. That transaction effectively tripled our proved reserves and doubled our production. Since 2005, we have principally focused on exploration and development drilling and have funded these investments with cash flow provided by operating activities.

Market Conditions

Beginning in the fourth quarter of 2008, severe financial market disruptions and global economic contraction contributed to large decreases in the prices we received for our oil and gas production. Our oil price realizations for 2009 averaged $56 per barrel, 42% less than our 2008 average of $96 per barrel. Our average gas price dropped 51% to $4.12 per Mcf during 2009 from $8.43 per Mcf in 2008. The large decrease in price resulted in a significant decrease in the amount of cash flow available to invest in exploration and development. In response, we sharply reduced our drilling activity. In 2009 we drilled 76% fewer wells as compared to 2008. Our total capital investment in exploration and development during 2009 was just $524 million versus $1.4 billion in 2008.

In early 2010, oil and gas prices have improved and the cost to drill and complete our wells has decreased. We have begun to increase our drilling activity and our exploration and development capital investment for 2010 is presently expected to range from $700-$900 million.

2009 Summary

During 2009 we accomplished the following positive highlights:

- Increased proved reserves 15% to 1.53 Tcfe

Table of Contents

Added 312 Bcfe of proved reserves from extensions, discoveries and improved recovery, replacing 185 percent of production.

Reduced drilling costs and improved our well performance in our western Oklahoma, Cana-Woodford shale play ending the year with 225 Bcfe of proved reserves.

By year-end, had brought on approximately 100 MMcfe/d of new production in southeast Texas.

Reduced borrowings outstanding under our revolving credit facility by $195 million, exiting the year with a debt to total capitalization ratio of 16 percent.

However, largely as a result of low oil and gas prices we also:

Recorded a first-quarter 2009 non-cash full-cost ceiling test write-down of oil and gas properties of $502 million after-tax.

Had a net loss for 2009 of $311.9 million.

Business Strategy

Our principal business objective is to profitably grow our proved reserves and production for the long-term benefit of our shareholders. Our strategy centers on maximizing cash flow from our producing properties and profitably reinvesting that cash flow in exploration and development. During 2009, our cash flow from operating activities totaled approximately $675 million. Our 2009 investment in exploration and development was $524 million.

A cornerstone to our approach is a detailed evaluation of each drilling decision based on its risk-adjusted discounted cash flow rate of return on investment. Our analysis includes estimates and assessments of potential reserve size, geologic and mechanical risks, expected costs, future production profiles and future oil and gas prices.

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 to the originating exploration team in order to help them improve and refine future investment decisions. We believe that our detailed technical analysis and disciplined capital investment process mitigates risk and positions us to continue to achieve consistent increases in proved reserves and production.

While our primary focus is drilling, we occasionally consider acquisition and merger opportunities that allow us to either enhance our competitive position in existing core areas or to add new areas. The 2005 Magnum Hunter acquisition significantly increased our presence in the Permian Basin and enhanced our Mid-Continent operations in the Texas Panhandle. In 2008, we acquired 38,000 net acres in our western Oklahoma Cana-Woodford shale play. The cost of that acquisition was $180.9 million.

Conservative use of leverage has long been a part of our financial strategy. We believe that maintaining a strong balance sheet mitigates financial risk and enables us to withstand low prices. At year-end 2009 we had $393 million of long-term debt and our debt to total capitalization ratio was 16 percent.

Business Segments

Cimarex has one reportable segment (exploration and production).

Table of Contents

Exploration and Development Overview

Our exploration and development activities are conducted within three main areas: the Mid-Continent region, the Permian Basin and the Gulf Coast. The Mid-Continent region consists of Oklahoma, the Texas Panhandle and southwest Kansas. The Permian Basin encompasses west Texas and southeast New Mexico. Our Gulf Coast operations are currently focused in southeast Texas. We also have a gas field development project underway in Wyoming.

A summary of our 2009 exploration and development (E&D) activity by region is as follows.

	Exploration and Development Capital (in millions)	Gross Wells Drilled	Net Wells Drilled	Completion Rate	12/31/09 Proved Reserves (Bcfe)
Mid-Continent	$ 251	51	22	98%	730.4
Permian Basin	155	49	36	90%	487.3
Gulf Coast	106	9	8	89%	106.0
Wyoming/Other	12	1	1	0%	211.0
	$ 524	110	67	93%	1,534.7

Company-wide, we participated in drilling 110 gross wells during 2009, with an overall completion rate of 93 percent. On a net basis, 60 of 67 total wells drilled during 2009 were completed as producers.

Our 2009 E&D investment totaled $524 million and resulted in 312 Bcfe of proved reserve additions. Of total expenditures, 48 percent were invested in projects located in the Mid-Continent area; 30 percent in the Permian Basin; and 20 percent in the Gulf Coast.

Mid-Continent

Our Mid-Continent region encompasses operations in Oklahoma, southwest Kansas and the Texas Panhandle. We drilled 51 gross (22 net) Mid-Continent wells during 2009, completing 98 percent as producers. The bulk of this drilling activity is directed at gas-bearing geological formations in the Anadarko Basin of western Oklahoma. Full-year 2009 investment in this area was $251 million, or 48 percent of total E&D capital.

We drilled 44 gross (17 net) Anadarko Basin wells, of which 98 percent were completed as producers. Our largest investment in this area is in the western Oklahoma, Cana-Woodford shale play. We have approximately 94,000 net acres in the play.

The Cana-Woodford formation is a shale interval that varies in thickness from 120-280 feet at depths of 12,000-16,000 feet throughout our acreage. During 2009, we drilled and completed 35 gross (13.6 net) horizontal Cana-Woodford wells. At year-end there were 11 gross (6.3 net) wells waiting on completion.

Since the Cana play began in late 2007, Cimarex has participated in a total of 75 gross (32.8 net) wells. Of which, 58 gross (23.7 net) wells have been brought on production and the remainder were either in the process of being drilled or awaiting completion at year-end 2009. For the 58 producing wells, average estimated gross ultimate recovery exceeds 6.5 Bcfe per well. Our acreage positions have multiple years of drilling opportunity.

In the Texas Panhandle, we drilled 2 gross (2 net) successful Granite Wash wells. Our land position in the Texas Panhandle is primarily in Roberts and Hemphill counties.

Table of Contents

Permian Basin

Our Permian Basin operations cover both west Texas and southeast New Mexico. In total, we drilled 49 gross (36 net) wells in this area during 2009 completing 44 gross (32 net) as producers. Full-year 2009 investment in this area totaled $155 million, or 30 percent of total E&D capital. Our 2009 drilling focused on horizontal oil plays.

Southeast New Mexico drilling, mainly targeting the Bone Spring, Cherry Canyon, Abo, Paddock and Wolfcamp formations, totaled 38 gross (30 net) wells with 87% being completed as producers.

Gulf Coast

Our current Gulf Coast exploration drilling is primarily in southeast Texas. This effort is generally characterized by reliance on three-dimensional (3-D) seismic information for prospect generation. We also experience larger potential reserves per well, greater drilling depths and lower success rates. Full-year 2009 investment in the Gulf Coast area was $106 million, or 20 percent of total E&D capital. During 2009 we drilled 9 gross (8.1 net) Gulf Coast wells, realizing an 89 percent success rate. The majority of the activity occurred near Beaumont in Jefferson County, Texas, where seven gross (6.9 net) Yegua/Cook Mountain wells were drilled.

We also own interests offshore Louisiana on the Gulf of Mexico shelf (water depth less than 300 feet). We obtained all of our offshore position through the Magnum Hunter acquisition. Our 2009 activity in this area consisted primarily of workovers and recompletions.

Other

We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. During 2009 we invested a total of $20.1 million in this project and our cumulative investment in this project is $70.9 million. We presently expect that we will initiate gas sales from this project in 2011. Our total investment, including planned expansion, will approximate $200 million.

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,		
	2009	**2008**	**2007**
Production Volumes:			
Gas (MMcf)	117,968	127,444	119,937
Oil (MBbls)	8,498	8,395	7,445
Equivalent (MMcfe)	168,956	177,814	164,607
Net Average Daily Volumes:			
Gas (MMcf)	323.2	348.2	328.6
Oil (MBbls)	23.3	22.9	20.4
Equivalent (MMcfe)	462.9	485.8	451.0
Average Sales Price:			
Gas ($/Mcf)	$ 4.12	$ 8.43	$ 7.05
Oil ($/Bbl)	$ 56.13	$ 96.03	$ 69.71

Total 2009 oil and gas production fell five percent averaging 462.9 MMcfe per day as compared to 485.8 MMcfe per day in 2008. Gas production in 2009 decreased seven percent to 323.2 MMcf per day and oil production grew one percent to 23,283 barrels per day.

Table of Contents

Production changes reflect the early-2009 reduction in company-operated drilling rigs and number of wells drilled. During the fourth quarter of 2008, we were running an average of 31 operated rigs. By the end of March 2009, we were operating only 3 rigs. In the second half of 2009 we began to pick up our drilling activity and had 12 rigs running during the fourth quarter. In total, we drilled and completed 110 gross (67 net) wells during 2009 compared to 450 gross (276.9 net) in 2008. Partially offsetting the impact of the sharp reduction in drilling were four new highly productive wells in southeast Texas that contributed 70 MMcfe/d to our average fourth quarter volumes.

Reflecting weaker overall U.S. gas markets, we sold our 2009 gas at an average price of $4.12 per Mcf, which was 51 percent lower than the $8.43 per Mcf we received in 2008. Declining global oil prices negatively impacted the oil prices we received. Our annual average realized oil price during 2009 dropped 42 percent to $56.13 per barrel from $96.03 per barrel in 2008.

The following table summarizes Cimarex's daily production by region for 2009 and 2008.

	2009 Average Daily Production			**2008 Average Daily Production**		
	Oil (MBbl/d)	**Gas (MMcf/d)**	**Total (MMcfe/d)**	**Oil (MBbl/d)**	**Gas (MMcf/d)**	**Total (MMcfe/d)**
Mid-Continent	5.1	187.8	218.5	5.6	190.3	223.9
Permian Basin	13.8	78.9	161.4	12.9	88.6	166.2
Gulf Coast	4.3	54.2	80.2	4.3	65.8	91.3
Other	0.1	2.3	2.8	0.1	3.5	4.4
	23.3	323.2	462.9	22.9	348.2	485.8

Our largest producing area is the Mid-Continent region. During 2009 our Mid-Continent production averaged 218.5 MMcfe per day, or 47 percent of our total 2009 production. Limited drilling activity outside of the western Oklahoma Cana-Woodford resulted in Mid-Continent production decreasing two percent in 2009.

The Permian Basin contributed 161.4 MMcfe per day in 2009, which was 35 percent of our total production. Oil production increased seven percent as a result of successful drilling in Bone Spring, Cherry Canyon, Abo, Paddock and Wolfcamp formations in southeast New Mexico and West Texas.

Gulf Coast production averaged 80.2 MMcfe per day during 2009, or 17 percent of total production. Full-year 2009 Gulf Coast volumes decreased 12 percent as compared to 2008 as a result of natural production declines and the timing of exploration success. Successful exploration drilling in the second-half of 2009 near Beaumont Texas, resulted in production volumes increasing to 116.2 MMcfe/d, a 54 percent increase over fourth-quarter 2008 average of 75.7 MMcfe/d.

Acquisitions and Divestitures

During 2009, we sold various oil and gas properties for a total of $109.4 million. Associated proved reserves were 25 Bcfe. The largest transaction was $79 million for an interest in a West Texas secondary oil field. There were no significant acquisitions during 2009. Subsequent to year end we acquired additional interests in our Western Oklahoma Cana-Woodford shale play for approximately $23 million.

During 2008 we sold interests in various oil and gas properties primarily located in South Texas for $38.1 million. Also during 2008, we purchased 38,000 undeveloped acres in western Oklahoma for $180.9 million.

In 2005, Cimarex acquired Magnum Hunter Resources, Inc, an independent oil and gas exploration and production company with operations concentrated in the Permian Basin and 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 (60 percent gas and 73 percent proved developed).

Table of Contents

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.

We sell our oil and gas to a broad portfolio of customers. Our largest customer accounted for approximately 14 percent of 2009 revenues. Because over 95 percent of our gas production is from wells in Kansas, Oklahoma, New Mexico, 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 756 people on December 31, 2009. 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 greater financial and human resources. The effect of these competitive factors 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. Nevertheless, we are involved in title disputes from time to time which result in litigation. Our oil and gas properties are subject to customary royalty interests, 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 extensive federal, state and local laws and regulations. Compliance with existing laws often is difficult and costly, but has not had a significantly adverse effect upon our operations or financial condition. In recent years, we have been most directly affected by federal and state environmental regulations and energy conservation rules. We are also indirectly affected by federal and state regulation of pipelines and other oil and gas transportation systems.

The states in which we conduct operations establish requirements for drilling permits, the method of developing new fields, the size of well spacing units, drilling density within productive formations and the unitization or pooling of properties. In addition, state conservation laws include requirements for waste prevention, establish limits on the maximum rate of production from wells, generally prohibit the venting

Table of Contents

or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to 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.

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.

We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our financial position or operations. However, due to continuing changes in these laws and regulations, we are unable to predict with any reasonable degree of certainty any potential delays in development plans that could arise, or our future costs of complying with these governmental requirements. We do maintain levels of insurance customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, produced water or other substances.

Gas Gathering and Transportation. The Federal Energy Regulatory Commission (FERC) requires interstate gas pipelines to provide open access transportation. FERC also enforces the prohibition of market manipulation by any entity, and the facilitation of the sale or transportation of natural gas in interstate commerce. Interstate pipelines have implemented these requirements, providing 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 FERC oversight, our natural gas gathering systems and services may receive regulatory scrutiny by state and Federal agencies regarding the safety and operating aspects of the transportation and storage activities of these facilities.

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.

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.

Table of Contents

Federal and State Income and Other Local Taxation

Cimarex and the petroleum industry in general are affected by both federal and state income tax laws, as well as other local tax regulations involving ad valorem, personal property, franchise, severance and other excise taxes. 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. These risks and uncertainties are not the only ones we face. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations. If any of the following risks and uncertainties actually occurs, our business, financial condition or results of operations could be materially adversely affected, and these events could negatively impact the value of our common stock.

Oil and gas prices fluctuate due to a number of uncontrollable factors, creating a component of uncertainty in our development plans and overall operations. Declines in prices adversely affect our financial results and rate of growth in proved reserves and production.

Oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control. These factors include, but are not limited to, changes in global supply and demand for oil and gas, the actions of the Organization of Petroleum Exporting Countries, the level of global oil and gas exploration and production activity, weather conditions, technological advances affecting energy consumption, domestic and foreign governmental regulations, proximity and capacity of oil and gas pipelines and other transportation facilities and the price and technological advancement of alternative fuels.

The downward pressure in natural gas prices that began in the last half of 2008 continued in 2009. Our average realized natural gas price for 2009 decreased 51% from 2008. Additionally, although oil prices have improved since the end of 2008, our average realized price for oil for 2009 was down 42% from 2008. The decrease in prices significantly decreased the amount available to invest in exploration and development drilling and the present value of our proved reserves. As a result of the drop in commodity prices in the first quarter of 2009, we recorded a $502 million after-tax, full-cost ceiling test write-down of proved properties book-value.

Our proved oil and gas reserves and production volumes 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. Low prices 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. 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.

If oil and natural gas prices decrease further, we may be required to take additional write-downs of the carrying values of our oil and gas properties and/or our goodwill.

Accounting rules require that we review the carrying value of our oil and gas properties and goodwill for possible impairment at the end of each reporting period. If prices decrease significantly, we may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders, purchasers of our oil and gas production and working interest owners in properties we operate, causing them to fail to meet their obligations to us.

Failure to economically replace commercial quantities of new oil and gas reserves could negatively affect our financial results and future rate of growth.

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. This can require significant capital expenditures and can impose reinvestment risk for our company, as we may not be able to continue to replace our reserves economically. 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.

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.

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.

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

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

- production rates, reservoir pressure, unexpected water encroachment, and other subsurface conditions;
- future oil and gas prices;
- effects of governmental regulation;
- future operating costs;
- future property, severance, excise and other taxes incidental to oil and gas operations;
- capital expenditures;
- work-over and remedial costs; and

13

Table of Contents

- Federal and state income taxes.

The estimation of the category of proved undeveloped reserves can be subject to an even greater possibility of revision. At December 31, 2009, 23 percent of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 61 percent are related to a project in Wyoming and 33 percent are from the western Oklahoma, Cana-Woodford shale play.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with guidelines established by the 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, 2009.

The cash flow amounts 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 the average of the previous twelve months' prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially different.

Hedging transactions may limit our potential gains and involve other risks.

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

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

- the counterparties to our futures contracts fail to perform under the contracts;
- a sudden unexpected event materially impacts oil and natural gas prices;
- our production is less than expected; or
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement.

Because all of our derivative contracts are accounted for under mark-to-market accounting, we expect continued volatility in derivative gains or losses on our income statement as changes occur in the relevant price indexes.

We have been an early entrant into new or emerging resource development projects; as a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage may decline and we may incur impairment charges if drilling results are unsuccessful.

New or emerging oil and gas resource development projects have limited or no production history. Consequently, we may be unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage may decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays.

Unless production is established during the term of certain of our undeveloped oil and gas leases, the leases will expire, and we will lose our right to develop the related properties.

Table of Contents

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

The marketability of our oil and natural gas production depends in large part on the availability, proximity and capacity of pipeline systems owned by third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. The lack of availability of these facilities for an extended period of time could negatively affect our revenues. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

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.

In addition, studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," may be impacting the earth's climate. Methane, a primary component of natural gas, and carbon dioxide, a by-product of the burning of oil and natural gas, are examples of greenhouse gases. The U.S. Congress and various states have been evaluating climate-related legislation and other regulatory initiatives that would restrict emissions of greenhouse gases. In December 2009, the Environmental Protection Agency (EPA) issued findings that methane and carbon dioxide present a health and safety issue such that they should be regulated under the Clean Air Act. Restrictions resulting from legislation by Federal or state legislators, or regulations imposed by the EPA, may have an effect on demand for our products, and may result in additional compliance obligations with respect to the release, capture and use of carbon dioxide that could have an adverse effect on our operations.

We make extensive use of hydraulic fracturing, a process that creates a fracture extending from the well bore in a rock formation, to enable gas or oil to move more easily through the rock pores to a production well. Fractures are typically created through the injection of water, chemicals and sand into the rock formation. Legislative and regulatory efforts at the Federal level and in some states have been made to render permitting and compliance requirements more stringent for hydraulic fracturing. Such efforts could have an adverse effect on our operations.

Table of Contents

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 18 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 may not be able to generate enough cash flow to meet our debt obligations.

At December 31, 2009, we had total long-term debt of $392.8 million, consisting of $25.0 million of bank debt, $350 million of unsecured 7.125% Senior Notes and $17.8 million of Convertible Notes ($19.45 million face value). Subject to the limits contained in the agreements governing our senior revolving credit facility, we have a borrowing base of $1 billion as of December 31, 2009, with current bank commitments of $800 million. We have demands on our cash resources in addition to interest expense and principal on our long-term debt, including, among others, operating expenses and capital expenditures.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon our future performance and our ability to repay or refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital market conditions, our financial condition, results of operations and prospects and other factors, many of which are beyond our control. Our ability to meet our debt service obligations may also be affected by changes in prevailing interest rates, as borrowing under our existing senior revolving credit facility and our Convertible Notes bear interest at floating rates.

Our business may not generate sufficient cash flow from operations, nor could there be adequate future sources of capital to enable us to service our indebtedness, or to fund our other liquidity needs. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;

Table of Contents

- selling assets; or
- restructuring or refinancing debt.

We may be unable to complete any such strategies on satisfactory terms, if at all. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations.

The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indentures governing our senior subordinated notes and credit agreement contain various restrictive covenants that may potentially limit our management's discretion in certain respects. In particular, these agreements will limit our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our subordinated debt;
- make loans to others;
- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of us and our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, our revolving credit agreement requires us to maintain a debt to EBITDA ratio (as defined in the credit agreement) of less than 3.5 to 1 and a current ratio (defined to include undrawn borrowings) of greater than 1 to 1. Also, the indentures under which we issued our senior unsecured notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.25 to 1. The additional indebtedness limitation does not prohibit us from borrowing under our $1.0 billion revolving credit facility. See Note 7, Long-term Debt, in Notes to Consolidated Financial Statements for further information.

If we fail to comply with the restrictions in the indentures governing our senior notes or credit facility or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Table of Contents

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 problems and difficulties related to the acquisition. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such review will not reveal all existing or potential problems. Our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Therefore, the purchase price we pay may exceed the value we realize. When we make entity acquisitions, we may have transferee liability that is not fully indemnified. Acquisitions may have an adverse effect on our operating results, particularly during the periods in which the operations of acquired businesses are being integrated into our ongoing operations.

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.

Our 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 our stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Oil and Gas Properties and Reserves

Effective December 31, 2009, the SEC and the Financial Accounting Standards Board ("FASB") adopted amendments to required oil and gas reporting disclosures. The amendments were designed to modernize disclosure requirements and to align them with current practices and changes in technology. The revised rules require reserve calculations to be based on the unweighted average first-day-of-the-month prices for the prior twelve months. In prior years proved reserves were based on

Table of Contents

prices in effect at period end. The current rules permit the use of additional technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about recoverable volumes. Companies may also disclose their probable and possible reserves to investors. We have chosen to not make disclosures of unproved reserves in our SEC filings. The effect of our adoption of the new rules was minimal, apart from the change to using the 12-month average pricing.

Proved oil and gas reserve quantities are based on estimates prepared by Cimarex in accordance with guidelines established by the SEC. Reserve definitions comply with definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. All reserve estimates of Cimarex are maintained by the Company's internal Corporate Reservoir Engineering group, which is comprised of reservoir engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of the company. The technical employee primarily responsible for overseeing the oil and gas reserve estimation process is the company's Vice President Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than fifteen years of practical experience in oil and gas reserve evaluation. This individual has been directly involved in the annual SEC reserve reporting process of Cimarex since 2002 and serving in the current role for the past five years.

DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, reviewed greater than eighty percent of the total future net revenue discounted at ten percent attributable to the total interests owned by Cimarex as of December 31, 2009. The technical individual primarily responsible for overseeing the reserves review is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over thirty-five years of experience in oil and gas reservoir studies and evaluations.

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 79 percent of our proved reserves. All information in this Form 10-K relating to oil and gas reserves is net to our interest unless stated otherwise. See Note 17, Unaudited 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,		
	2009	**2008**	**2007**
Total Proved Reserves			
Gas (MMcf)	1,186,585	1,067,333	1,122,694
Oil, condensate and NGLs (MBbls)	58,017	45,202	58,250
Equivalent (MMcfe)	1,534,689	1,338,545	1,472,195
Standardized measure of discounted future net cash flow after-tax, discounted at 10 percent (in thousands)	$ 1,667,955	$ 1,724,253	$ 2,897,631
Average price used in calculation of future net cash flow			
Gas ($/Mcf)	$ 3.56	$ 5.33	$ 6.51
Oil ($/Bbl)	$ 57.58	$ 36.34	$ 93.66

At December 31, 2009, the impact of adopting the new rules requiring the use of a twelve month average price, rather than prices in effect at year end, was significant to our reserve volumes and more so to our reserve values. At year end the reference prices for gas and oil were $5.79 per MMBtu and $79.36 per barrel, respectively, whereas the twelve month average reference prices were $3.87 per MMBtu and $61.18 per barrel. Adjusted for regional differentials, the average prices used were $3.56 per Mcf and $57.58 per barrel. Had prices in effect at year end been used, we believe our December 31, 2009 total equivalent proved reserve volumes would be approximately five to six percent greater than those calculated

Table of Contents

using the average price. We estimate that the Standardized Measure at year end would be approximately 60 percent greater if prices in effect at year end had been used.

Significant Properties

As of December 31, 2009, 79 percent of proved reserves were located in the Mid-Continent and Permian Basin regions. In total we owned an interest in 12,320 gross (4,748 net) productive oil and gas wells.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2009.

	Oil (MBbl)	Gas (Bcf)	Equivalent (Bcfe)	Percent of Proved Reserves
Mid-Continent	10,869	665.2	730.4	47%
Permian Basin	41,938	235.7	487.3	32%
Gulf Coast	5,170	75.0	106.0	7%
Wyoming/Other	40	210.7	211.0	14%
	58,017	1,186.6	1,534.7	100%

Our ten largest producing fields hold 35 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
Watonga-Chickasha	Mid-Continent	14.9%	40.1%	13,000'	Woodford Shale
Eola-Robberson	Mid-Continent	3.5%	88.5%	5,500' - 11,000'	Bromide/McLish/Oil Creek
Constitution	Gulf Coast	3.1%	98.7%	14,000'	Yegua
Hemphill	Mid-Continent	2.9%	94.9%	11,000'	Granite Wash
Phantom	Permian Basin	2.8%	95.7%	11,500'	Bone Spring
Mendota NW	Mid-Continent	2.6%	74.7%	11,000'	Granite Wash
Jo-Mill	Permian Basin	1.7%	13.1%	7,500'	Spraberry
Quail Ridge	Permian Basin	1.5%	73.5%	8,000' - 13,000'	Bone Spring/Morrow
Wildcat	Permian Basin	1.2%	71.2%	9,000'	Abo
Two Georges	Permian Basin	1.1%	91.1%	11,500'	Bone Spring
		35.3%			

Table of Contents

Acreage

The following table sets forth as of December 31, 2009, 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	20,999	18,397	146,059	103,418	167,058	121,815
Oklahoma	142,985	129,595	451,259	207,891	594,244	337,486
Texas	126,441	112,582	189,520	118,307	315,961	230,889
	290,425	260,574	786,838	429,616	1,077,263	690,190
Permian Basin						
New Mexico	114,924	88,601	170,459	114,872	285,383	203,473
Texas	73,322	46,785	196,103	129,430	269,425	176,215
	188,246	135,386	366,562	244,302	554,808	379,688
Gulf Coast						
Louisiana	7,797	3,196	19,426	5,441	27,223	8,637
Mississippi	7,465	5,709	8,339	5,673	15,804	11,382
Texas	107,647	67,763	130,240	52,902	237,887	120,665
Offshore	56,172	23,627	166,835	54,745	223,007	78,372
	179,081	100,295	324,840	118,761	503,921	219,056
Other						
Arkansas	220	55	4,184	1,596	4,404	1,651
Arizona	920,269	920,269			920,269	920,269
California	1,482	1,482	364	364	1,846	1,846
Colorado	126,165	37,396	28,529	6,510	154,694	43,906
Illinois	1,782	1,191	511	140	2,293	1,331
Michigan	53,951	53,951	598	598	54,549	54,549
Montana	39,392	12,202	10,612	2,837	50,004	15,039
Nebraska	9,261	1,038	1,043	168	10,304	1,206
Nevada	1,007,327	1,007,168	440		1,007,767	1,007,168
New Mexico	1,652,662	1,635,575	19,421	2,477	1,672,083	1,638,052
North Dakota	64,052	25,837	8,380	1,194	72,432	27,031
South Dakota	9,946	9,134	2,414	373	12,360	9,507
Texas	64,124	64,124			64,124	64,124
Utah	104,764	59,351	33,950	2,543	138,714	61,894
Wyoming	205,929	23,403	94,100	16,093	300,029	39,496
	4,261,326	3,852,176	204,546	34,893	4,465,872	3,887,069
	4,919,078	4,348,431	1,682,786	827,572	6,601,864	5,176,003

Table of Contents

Gross Wells Drilled

We participated in drilling the following number of gross wells during calendar years 2009, 2008, and 2007:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2009	7	4	11	95	4	99
Year ended December 31, 2008	36	16	52	384	14	398
Year ended December 31, 2007	55	18	73	361	18	379

We were in the process of drilling 16 gross (9.7 net) wells at December 31, 2009 and there were 11 gross (6.3 net) Cana-Woodford wells waiting on completion.

Net Wells Drilled

The number of net wells we drilled during calendar years 2009, 2008, and 2007 are shown below:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2009	5.6	3.8	9.4	54.1	3.5	57.6
Year ended December 31, 2008	25.9	13.6	39.5	226.5	10.9	237.4
Year ended December 31, 2007	36.7	13.1	49.8	221.9	9.6	231.5

Productive Wells

We have working interests in the following productive wells as of December 31, 2009:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	3,972	2,069	1,012	519
Permian	1,049	577	5,393	1,325
Gulf Coast	446	151	338	103
Other	81	3	29	1
	5,548	2,800	6,772	1,948

ITEM 3. LEGAL PROCEEDINGS

In January 2009, the Tulsa County District Court issued a judgment in the H.B. Krug, et al versus Helmerich & Payne, Inc. ("H&P") case. This lawsuit was originally filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. Damages of $6.9 million, plus $119.5 million for disgorgement of H&P's estimated potential compounded profit since 1989 resulting from the noted damages, were awarded to plaintiff royalty owners for a total of $126.4 million. This amount was subsequently adjusted by the court to a total of $119.6 million. Pursuant to the 2002 spin-off transaction to shareholders of H&P by which Cimarex became a publicly-traded entity, Cimarex assumed the assets and liabilities of H&P's exploration and production business. In 2008 we had accrued litigation expense of $119.6 million for this lawsuit. During 2009, we have accrued an additional $9.4 million. We have appealed the District Court's judgments.

In the normal course of business, we have other various litigation related matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. For the year 2009, we had approximately $10.0 million of such expenses. Though some of the related claims may be significant, the resolution of them we believe, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations.

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 2009.

ITEM 4A. EXECUTIVE OFFICERS

The executive officers of Cimarex as of February 26, 2010 were:

Name	Age	Office
F.H. Merelli	73	Chairman of the Board, Chief Executive Officer, and President
Joseph R. Albi	51	Executive Vice President, Operations
Thomas E. Jorden	52	Executive Vice President, Exploration
Stephen P. Bell	55	Senior Vice President, Business Development and Land
Paul Korus	53	Vice President, Chief Financial Officer, and Treasurer
Gary R. Abbott	37	Vice President, Corporate Engineering
Richard S. Dinkins	65	Vice President, Human Resources
James H. Shonsey	58	Vice President, Chief Accounting Officer, and Controller
Thomas A. Richardson	64	Vice President, General Counsel

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

23

Table of Contents

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.

THOMAS A. RICHARDSON joined Cimarex in August 2008 and was elected vice president and general counsel on September 20, 2008. Mr. Richardson retired as a senior partner of Holme Roberts & Owen LLP, a Denver law firm, in December 2007. Mr. Richardson joined Holme Roberts in June 1970 and served as a partner of the firm from 1975 to his retirement. His specialties at the firm included corporate, securities and merger and acquisition law.

Table of Contents

PART II

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

Our $.01 par value common stock trades on the New York Stock Exchange under the symbol XEC. A cash dividend of $.06 per share was paid to shareholders in each quarter of 2009. 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.

2009	**High**	**Low**	**Dividends Paid Per Share**
First Quarter	$ 30.86	$ 15.35	$ .06
Second Quarter	$ 35.20	$ 17.66	$ .06
Third Quarter	$ 44.41	$ 25.06	$ .06
Fourth Quarter	$ 54.55	$ 37.62	$ .06

2008	**High**	**Low**	**Dividends Paid Per Share**
First Quarter	$ 56.53	$ 37.03	$ .06
Second Quarter	$ 74.50	$ 54.35	$ .06
Third Quarter	$ 72.00	$ 42.85	$ .06
Fourth Quarter	$ 48.94	$ 22.38	$ .06

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 19, 2010, was $59.98. At December 31, 2009, Cimarex's 83,541,995 shares of outstanding common stock were held by approximately 4,092 stockholders of record.

Table of Contents

The graph below compares the cumulative 5-year total return of holders of Cimarex Energy Co.'s common stock with the cumulative total returns of the S&P 500 index and the Dow Jones US Exploration & Production index. The graph tracks the performance of a $100 investment in our common stock and in each of the indexes (with the reinvestment of all dividends) from 12/31/2004 to 12/31/2009.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Cimarex Energy Co., The S&P 500 Index
And The Dow Jones US Exploration & Production Index

	12/04	12/05	12/06	12/07	12/08	12/09
Cimarex Energy Co.	**100.00**	**113.48**	**96.70**	**113.14**	**71.63**	**142.74**
S&P 500	**100.00**	**104.91**	**121.48**	**128.16**	**80.74**	**102.11**
Dow Jones US Exploration & Production	**100.00**	**165.32**	**174.20**	**250.27**	**149.86**	**210.65**

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

ITEM 5C. STOCK REPURCHASES

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of our common stock. The authorization is currently set to expire on December 31, 2011. Through December 31, 2007, we had repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. Purchases may be made in both the open market and through negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice. There were no shares repurchased in the fourth quarter of 2009, or since the quarter ended September 30, 2007.

Table of Contents

Issuer Purchases of Equity Securities for the Quarter Ended December 31, 2009

	Total Number of Shares purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of shares that may yet be Purchased Under the Plans or Programs
October, 2009	None	NA	None	2,635,700
November, 2009	None	NA	None	2,635,700
December, 2009	None	NA	None	2,635,700

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 Report.

	For the Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share amounts)				
Operating results:					
Revenues	$ 1,009,794	$ 1,970,347	$ 1,430,513	$ 1,265,400	$ 1,117,241
Net income (loss)	(311,943)	(915,245)	345,262	344,481	327,603
Earnings (loss) per share to common Stockholders:					
Basic					
Distributed	$ 0.24	$ 0.24	$ 0.18	$ 0.16	$ 0.00
Undistributed	(4.06)	(11.46)	3.97	3.96	3.94
	$ (3.82)	$ (11.22)	$ 4.15	$ 4.12	$ 3.94
Diluted					
Distributed	$ 0.24	$ 0.24	$ 0.18	$ 0.16	$ 0.00
Undistributed	(4.06)	(11.46)	3.87	3.89	3.86
	$ (3.82)	$ (11.22)	$ 4.05	$ 4.05	$ 3.86
Cash dividends declared per share	.24	.24	.18	.16	
Balance sheet data:					
Total assets	$ 3,444,537	$ 4,164,933	$ 5,362,794	$ 4,829,750	$ 4,180,335
Total debt	392,793	587,630	462,216	416,823	323,657
Stockholders' equity	2,038,106	2,351,647	3,275,128	2,993,192	2,613,740
Other financial data:					
Oil and gas sales	962,443	1,880,891	1,364,622	1,215,411	1,072,422
Oil and gas capital expenditures	528,041	1,620,778	1,023,434	1,074,673	2,462,826
Proved Reserves:					
Gas (MMcf)	1,186,585	1,067,333	1,122,694	1,090,362	1,004,482
Oil (MBbls)	58,017	45,202	58,250	59,797	64,710
Total equivalent (MMcfe)	1,534,689	1,338,545	1,472,195	1,449,146	1,392,742

Table of Contents

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

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements included in Item 8 of this report and also with *"Certain Risks"* in Item 1 of this report. Certain amounts in prior years' financial statements have been reclassified to conform to the 2009 financial statement presentation. This discussion also includes Forward-Looking statements. Please refer to "*Cautionary Information about Forward-Looking Statements*" in Part I of this Report for important information about these types of statements.

OVERVIEW

We are an independent oil and gas exploration and production company with operations entirely located in the United States. We have determined that our business is comprised of only one segment because our gathering, processing and marketing activities are ancillary to our production operations and are not separately managed.

Our operating strategy is to achieve profitable growth in proved reserves and production primarily through exploration and development. To supplement our growth and to provide for new drilling opportunities, we also consider mergers and acquisitions. Our growth is generally funded with cash flow provided by our operating activities. To achieve a consistent rate of growth and mitigate risk we have historically maintained a blended portfolio of low, moderate, and higher risk exploration and development projects. To further mitigate risk, we have chosen to seek geologic and geographic diversification by operating in multiple basins. Our operations are mainly located in Texas, Oklahoma, New Mexico, Kansas and Wyoming.

The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and the amount of our reported assets, liabilities and proved reserves. We use the full cost method of accounting for oil and gas activities.

Our revenue, profitability and future growth are highly dependent on the oil and gas prices we receive. Our ability to find, develop and/or acquire proved oil and gas reserves will also impact our financial results. Continued volatility in commodity prices, and turmoil in the global financial system may have adverse effects on our business and financial position. Our ability to access the capital markets may be restricted, which could have an impact on our flexibility to react to changing economic and business conditions. Further, the global economic situation could have an impact on our lenders, business partners and customers, potentially causing them to fail to meet their obligations to us.

Oil and gas prices reached historically high levels during the first nine months of 2008. However, during the fourth quarter of 2008 severe disruptions in the credit markets and reductions in global economic activity caused significant decreases in oil and gas prices. The downward pressure on natural gas prices continued in 2009. Our average realized natural gas price for 2009 decreased 51% compared to the 2008 realized price. Oil prices improved as 2009 unfolded but they are still significantly lower than prices received in 2008. Our average realized oil price during 2009 was 42% lower than the realized price for 2008. This dramatic decrease in both oil and gas prices had a significant negative impact on our 2009 revenue and net income. We also had less cash flow available for capital expenditures. Our stock price and market capitalization have also been adversely affected by these economic events.

***2009 Summary*:**

Lower oil and gas prices negatively impacted our 2009 revenues, earnings and cash flow. We reported a net loss of $311.9 million, or $3.82 per share. The 2009 loss was primarily the result of a first quarter full-cost ceiling test write down of our oil and gas properties of $501.8 million (after tax). Substantially all

Table of Contents

of this noncash charge was the result of the continuing drop in commodity prices that began during the fourth quarter of 2008. Despite the impact of lower prices, we made several meaningful accomplishments during 2009. Most notably, we increased our proved reserves by 15% and have positioned the company to achieve 17-23% production volume growth in 2010.

2009 summary financial and operating results:

- Proved reserves increased 15% to 1.53 Tcfe.
- Oil and gas production volumes averaged 462.9 MMcfe/d, down from 485.8 MMcfe/d for 2008.
- Oil and gas sales declined 49% to $962.4 million from $1.88 billion a year earlier.
- Net loss of $311.9 million, or $3.82 per diluted share, versus a loss of $915.2 million, or $11.22 per share in 2008.
- Cash flow from operating activities was $675.2 million, down from $1,367.5 million for 2008.
- Total debt decreased by $195 million to $393 million from $588 million at year-end 2008.

In response to the lower oil and gas prices we significantly reduced our 2009 capital expenditures from our record high in 2008. Total oil and gas capital expenditures for 2009 were $528 million, down from 2008 expenditures of $1.6 billion.

In October 2009 our bank group, as part of the regularly scheduled fall review, reaffirmed our $1.0 billion borrowing base related to our credit facility maturing in April 2012. Bank group commitments of $800 million also remain unchanged. As of December 31, 2009, we had bank borrowings outstanding of $25 million, which is $195 million less than the December 31, 2008 balance of $220 million. The reduction in borrowings was primarily funded from non-core property sales and tax refunds.

We sold various interests in oil and gas properties in 2009, the largest of which was a West Texas secondary oil recovery field. Total 2009 sales proceeds were $109.4 million, with associated proved reserves of 25 Bcfe. There were no significant acquisitions during 2009. Subsequent to year end we acquired additional interests in our Western Oklahoma Cana-Woodford shale play for approximately $23 million.

Oil and Gas Prices

While our revenues are a function of both production and prices, wide swings in commodity prices had the greatest impact on our results of operations. Our annual average realized gas price decreased from $8.43 per Mcf in 2008 to $4.12 per Mcf in 2009; and oil prices decreased from $96.03 per barrel in 2008 to $56.13 per barrel in 2009.

During the fourth quarter of 2008, reductions in global economic activity and energy demands caused significant decreases in oil and gas prices. Year-end 2008 oil and gas prices fell 50-70% from their mid-2008 peak. Though prices improved as 2009 unfolded, they remained substantially below prior year levels.

	Years Ended December 31,		
	2009	2008	2007
Gas Prices:			
Average Henry Hub price ($/Mcf)	$ 3.99	$ 9.04	$ 6.86
Average realized sales price ($/Mcf)	$ 4.12	$ 8.43	$ 7.05
Effect of hedges ($/Mcf)	$ 0.00	$ 0.09	$ 0.23
Oil Prices:			
Average WTI Cushing price ($/Bbl)	$ 61.81	$ 99.65	$ 72.28

Average realized sales price ($/Bbl)	$	56.13	$	96.03	$	69.71

Table of Contents

On an energy equivalent basis, 70% of our 2009 aggregate production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in approximately an $11.8 million change in our gas revenues. Similarly, 30% of our production was crude oil. A $1.00 per barrel change in our average realized crude oil sales price would have resulted in approximately an $8.5 million change in our oil revenues.

Hedging

In addition to supply and demand, oil and gas prices are affected by seasonal, economic and geo-political factors that we can neither control nor predict. From time to time we attempt to mitigate a portion of our price risk through the use of hedging transactions.

In March 2009 we entered into derivative gas contracts covering the period April 2009 through December 2009. The collars set a floor of $3.00 and a ceiling of $5.00 and covered approximately 148,000 MMBtu per day of our Mid-Continent gas production during the contract period. These contracts expired at December 31, 2009. We recognized a net gain of $1.4 million from the 2009 contracts.

For 2007 and 2008 we executed cash flow effective hedges covering approximately 24% of our overall 2007 gas production and 11% of our 2008 gas volumes. We hedged 29.2 million MMbtu and 14.6 million MMbtu for 2007 and 2008, respectively. As of December 31, 2008 all of our cash flow effective hedge contracts had expired.

During the second and third quarters of 2009 we entered into derivative contracts for a portion of our 2010 production. These contracts cover approximately 40% of our anticipated 2010 oil and gas production volumes. At December 31, 2009, we had the following outstanding contracts:

Natural Gas Contracts

					Weighted Average Price		
Period		**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**Swap**
Jan 10	Dec 10	Collar	100,000 MMBtu	PEPL	$ 5.00	$ 6.62	
Jan 10	Dec 10	Swap	40,000 MMBtu	PEPL			$ 5.18
Jan 10	Dec 10	Collar	20,000 MMBtu	HSC	$ 5.00	$ 6.85	

Oil Contracts

					Weighted Average Price	
Period		**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**
Jan 10	Dec 10	Collar	10,000 Bbls	WTI	$ 60.03	$ 92.07
Jan 10	Dec 10	Put/Floor	1,000 Bbls	WTI	$ 60.00	

(1) PEPL refers to Panhandle Eastern Pipe Line Company price and HSC refers to Houston Ship Channel price, both as quoted in Platt's Inside FERC on the first business day of each month. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

We did not choose to apply hedge accounting treatment to any of the 2009 and 2010 contracts. Settlements on these contracts will not impact our realized commodity prices during the periods they cover. Instead, any settlements on these contracts are shown as a component of operating costs and expenses as a realized (gain) loss on derivative instruments. See Note 4 to the Consolidated Financial Statements for additional information regarding our derivative instruments.

Table of Contents

Reserve replacement and growth

Due to lower oil and gas prices we sharply reduced our capital investments during 2009. In 2009, investments in oil and gas exploration, development and acquisition activities totaled $528 million versus $1.6 billion in 2008. Our exploration and development capital investment is expected to increase to $700-$900 million in 2010, depending on prices and corresponding cash flow.

Because oil and gas are non-renewable forms of energy resources, exploration and production companies face the challenge of resource depletion and natural production decline. Our operations also entail significant complexities that require the use of advanced technologies and highly trained personnel. Even when modern exploration technology is properly used, our geo-scientists still may not know conclusively if hydrocarbons will be present, the rate at which they will be produced, or economic viability. Future growth will continue to depend upon our ability to economically add reserves in excess of production.

Despite lower capital investment in 2009, our year-end total proved oil and gas reserves increased by 15% to 1.53 Tcfe from 1.34 Tcfe at year-end 2008. This increase is net of production of 169.0 Bcfe and property sales of 24.9 Bcfe. Reserves added from exploration and development and improved recovery totaled 312.3 Bcfe and 3.9 Bcfe were acquired via property purchases. Revisions of previous estimates added 73.9 Bcfe, comprised of 104.7 Bcfe from positive performance and lower operating costs, partially offset by 30.8 Bcfe from lower prices.

Proved natural gas reserves at year-end 2009 were 1.19 Tcf compared to 1.07 Tcf at year-end 2008. Natural gas comprised 77% and 80% of our total proved reserves at year-end 2009 and 2008, respectively. Our proved oil reserves at year-end 2009 were 58.0 MMBbls compared to 45.2 MMBbls at the end of 2008.

Overall, about 47% of our proved reserves are in our Mid-Continent region and 32% are in the Permian Basin. Our onshore Gulf Coast and other onshore operations collectively make another 20% of total proved reserves. Only 1% of our total proved reserves are in the Gulf of Mexico.

The process of estimating quantities of oil and gas reserves is complex. Significant decisions are required 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, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures. See Note 17, Unaudited Supplemental Oil and Gas Disclosures for more reserve information.

In most years our primary source for reserve replacement and growth is exploration and development (E&D). We invested $524.4 million on E&D during 2009 and $1,438.4 million in 2008. Approximately 48% of 2009 expenditures were in the Mid-Continent area, 30% in the Permian Basin, 20% in the Gulf Coast area, and 2% in Wyoming/Other. Cash flow from operating activities for 2009 totaled $675 million, which more than funded our drilling program.

Production and other operating expenses

The costs associated with finding and producing oil and gas are substantial. Some of these costs vary with oil and gas prices, some trend with production volume and some are a function of the number of wells we own. At the end of 2009, we owned interests in 12,320 wells.

Table of Contents

Production expense generally consists of the cost of power and fuel, direct labor, third-party field services, compression, water disposal, and certain maintenance activity necessary to produce oil and gas from existing wells.

Transportation expense is comprised of costs paid to move oil and gas from the wellhead to a specified sales 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.

Depreciation, depletion and amortization (DD&A) 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 (G&A) consist primarily of salaries and related benefits, office rent, legal fees, consultants, systems costs and other administrative costs incurred in our offices and not directly associated with exploration, development or production activities. While we expect these costs to increase with our growth, we also expect such increases to be proportionately smaller than our production growth.

Production taxes are 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.

Significant expenses that generally do not trend with production

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. Net stock compensation expense in 2009 was $9.3 million compared to $10.1 million in 2008.

The derivative fair value (gain) loss is the net realized and unrealized gain or loss on derivative financial instruments that do not qualify for hedge accounting treatment. The gain or loss fluctuates based on changes in the fair value of underlying commodities. For the year ended December 31, 2009, we recognized a net realized gain of $1.4 million for the contracts that settled and expired in 2009. For those contracts that cover the period January 1, 2010 to December 31 2010, we have recorded a non-cash fair value loss of $14.5 million at December 31, 2009.

RESULTS OF OPERATIONS

2009 compared to 2008

We recognized a net loss for 2009 of $311.9 million or $3.82 per share. This compares to a net loss of $915.2 million, or $11.22 per share for 2008. The lower loss in 2009 compared to 2008 is primarily the result of a lower non-cash full cost ceiling impairment write-down recorded in 2009 compared to the write-down

Table of Contents

in 2008. The full cost ceiling impairment is discussed further in the operating costs and expenses section below.

Oil and Gas Sales (In thousands or as indicated)	For the Years Ended December 31, 2009	2008	Percent Change Between 2009/2008	Price/Volume Analysis Price	Volume	Variance
Gas sales	$ 485,448	$ 1,074,705	-55%	$ (508,442)	$ (80,815)	$ (589,257)
Oil sales	476,995	806,186	-41%	(339,070)	9,879	(329,191)
Total oil and gas sales	$ 962,443	$ 1,880,891	-49%	$ (847,512)	$ (70,936)	$ (918,448)
Total gas volume MMcf	117,968	127,444	-7%			
Gas volume MMcf per day	323.2	348.2				
Average gas price per Mcf	$ 4.12	$ 8.43	-51%			
Effect of hedges per Mcf	$ 0.00	$ 0.09				
Total oil volume thousand barrels	8,498	8,395	1%			
Oil volume barrels per day	23,283	22,937				
Average oil price per barrel	$ 56.13	$ 96.03	-42%			

Oil and gas sales during 2009 totaled $962.4 million, compared to $1.88 billion in 2008. Of the $918.4 million decrease in sales between the two periods, $847.5 million related to lower prices and $70.9 million resulted from lower production volumes.

Compared to 2008, our 2009 oil production increased by one percent to an average of 23,283 barrels per day. This increase resulted in $9.9 million of incremental revenues. Gas volumes averaged 323.2 MMcf per day in 2009 compared to 348.2 MMcf per day in 2008, resulting in a decrease in revenues of $80.8 million. Total 2009 oil and gas production volumes were 462.9 MMcfe per day, down 22.9 MMcfe per day from 2008. During the fourth quarter of 2009, our gas production averaged 330.0 MMcf per day down from 350.3 MMcf per day (a six percent decrease) from the fourth quarter of 2008. Fourth quarter oil production decreased by four percent to 22,935 barrels per day from 23,907 barrels per day in 2008. The expected decrease in production volumes between the periods is primarily the result of reduced drilling. Our fourth quarter 2008 operated rig count averaged 31 dropping to a low of three rigs in the first quarter of 2009 and averaged 12 by the fourth quarter of 2009.

Average realized gas prices decreased by 51% to $4.12 per Mcf in 2009, compared to $8.43 per Mcf for 2008. This price decrease lowered gas sales by $508.4 million between the two periods. Included in our 2008 realized gas price is $11.3 million of cash receipts (a positive $0.09 per Mcf effect) from settlement of cash flow hedges on 40,000 MMBtu per day of Mid-Continent gas production.

Realized oil prices averaged $56.13 per barrel during 2009, compared to $96.03 per barrel in 2008. The decrease in oil sales resulting from this 42% decline in oil prices totaled $339.1 million.

The decreases in realized gas and oil prices were the result of overall market conditions.

	For the Years Ended December 31, 2009	2008
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering, processing and other revenues	$ 46,763	$ 87,757

Gas gathering and processing costs		(20,560)		(43,838)
Gas gathering and processing margin	$	26,203	$	43,919
Gas marketing revenues, net of related costs	$	588	$	1,699

Table of Contents

We sometimes transport, process and market third-party gas that is associated with our gas. In 2009, third-party gas gathering and processing contributed $26.2 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $43.9 million in 2008. Our gas marketing margin (revenues less purchases) decreased to $0.6 million in 2009 from $1.7 million in 2008. Changes in net margins from gas gathering, processing and marketing activities are the direct result of changes in volumes and overall market conditions.

	For the Years Ended December 31,		Variance Between
	2009	2008	2009/2008
Operating costs and expenses (in thousands):			
Impairment of oil and gas properties	$ 791,137	$ 2,242,921	$ (1,451,784)
Depreciation, depletion and amortization	265,699	547,404	(281,705)
Asset retirement obligation	12,313	8,796	3,517
Production	178,215	218,736	(40,521)
Transportation	33,758	38,107	(4,349)
Taxes other than income	75,634	130,490	(54,856)
General and administrative	41,724	44,500	(2,776)
Stock compensation, net	9,254	10,090	(836)
Loss on derivative instruments, net	13,059	0	13,059
Other operating, net	24,263	126,433	(102,170)
	$ 1,445,056	$ 3,367,477	$ (1,922,421)

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) decreased to $1.445 billion in 2009 compared to $3.367 billion in 2008.

The largest component of the change between periods is the non-cash impairment of oil and gas properties recorded in 2009 and 2008. As a result of declines in commodity prices, an impairment of $791.1 million ($501.8 million net of tax) was reported in the first quarter of 2009. In 2008 a total of $2.2 billion ($1.4 billion, net of tax) of impairments were recorded. Volatility of oil and gas prices could require us to record a ceiling test impairment write-down in future periods. The full cost method of accounting is discussed in detail under "Critical Accounting Policies and Estimates".

DD&A decreased $281.7 million between periods from $547.4 million in 2008 to $265.7 million in 2009. On a unit of production basis, DD&A was $1.57 per Mcfe in 2009 compared to $3.08 per Mcfe for 2008. The significant decrease is due to $3.0 billion of impairments to the carrying value of our oil and gas properties recorded during the last half of 2008 and the first quarter of 2009.

Asset retirement obligation expense rose to $12.3 million in 2009 from $8.8 million in 2008. The increase is due to plugging and abandonment costs being greater than our original asset retirement obligation estimates. This was primarily the result of hurricane damage to our offshore properties. This caused additional expenses to be incurred during site restoration.

Production costs decreased $40.5 million, or 19 percent, from $218.7 million ($1.23 per Mcfe) in 2008 to $178.2 million ($1.05 per Mcfe) in 2009. Our production costs consist of workover expense and lease operating expenses. We have seen a decrease in costs in both of these areas. A reduction in large scale workover projects caused a $13.9 million decrease. A decrease in lease operating expense of $26.6 million is attributable to the sale of producing properties in the last half of 2008 and early 2009 coupled with a significant decline in service costs in comparison to their peak in mid-2008.

Transportation costs decreased from $38.1 million in 2008 to $33.8 million in 2009. The decrease is the result of lower sales volumes and lower fuel costs from 2008 to 2009.

Table of Contents

Taxes other than income were $54.9 million lower, dropping from $130.5 million in 2008 to $75.6 million in 2009. The decrease between periods resulted from decreases in oil and gas sales stemming from significantly lower commodity prices and lower gas production volumes.

General and administrative (G&A) expenses decreased $2.8 million from $44.5 million in 2008 to $41.7 million in 2009. The decrease between periods is due to higher employee-benefit costs including bonus and severance costs, offset by lower legal costs and lower costs associated with having fewer employees.

A component of our operating costs and expenses in 2009 is a loss of $13.1 million on our derivative instruments. We recorded an unrealized loss of $14.5 million related to calendar 2010 contracts which is partially offset by $1.4 million of net realized gains on contract settlements in 2009. See Note 4 to the Consolidated Financial Statements for detailed information regarding our derivative instruments.

Other operating, net expense consists of costs related to various legal matters most of which pertain to litigation and contract settlements and title and royalty issues. In 2009, the decrease in Other operating, net to $24.3 million from $126.4 million was primarily related to the Tulsa County District Court issuing a judgment in the H.B. Krug case in 2008. The total accrued litigation expense for the year ended December 31, 2008 for this lawsuit was $119.6 million. We have appealed the District Court's judgments. For further information on this lawsuit and other litigation please see Contingencies under "Critical Accounting Policies and Estimates".

Other income and expense

Interest expense increased by $6.7 million, or 20%, primarily because of an increase in our average bank debt outstanding during the year. We had no borrowings on our credit facility during the first eleven months of 2008 and an average outstanding balance of approximately $270 million during 2009. Also, in comparison to 2008, we recognized an additional $4.3 million of deferred financing costs. These higher costs are the result of the new credit facility we entered into in April 2009. Partially offsetting these increases is a $3.7 million decrease in interest expense on our convertible notes due to the December 2008 repurchases of $105.5 million of the outstanding $125 million (face value) notes. We repurchased the notes with borrowings under our credit facility and recognized a $10.1 million loss on early extinguishment of debt in 2008.

Capitalized interest increased by $1.3 million due mostly to more costs associated with our unproved properties and construction project in 2009.

Other, net decreased from $10.3 million of income in 2008 to $16.3 million of expense in 2009. Components consist of miscellaneous income and expense items that will vary from period to period, including income and loss in equity investees, gain or loss on the sale or value of oil and gas well equipment, and interest income. The change from 2008 to 2009 is primarily the result of losses of $15.5 million related to oil and gas well equipment due to decreased value of drill pipe resulting from a significant slowing of drilling activity across the industry. In 2008 we had a gain of $21.8 million on the sale of oil and gas well equipment. Also included in our 2009 expense is a $2.4 million loss on the sale of an equity investment.

Income tax

During 2009, a net deferred income tax benefit of $176.5 million was recognized (the year end deferred tax benefit included $11.8 million of current income tax benefit). This compares with a 2008 net deferred income tax benefit of $536.4 million. The combined Federal and state effective income tax rates were 36.1% and 37.0% in the years of 2009 and 2008, respectively. The effective tax rate of 36.1% for 2009 differs from the statutory rate primarily due to the effects of state income taxes and the Domestic Production Activities allowance.

Table of Contents

RESULTS OF OPERATIONS

2008 compared to 2007

We recognized a net loss for 2008 of $915.2 million or $11.22 per share. This compares to net income of $345.3 million, or $4.05 per diluted share for the same period in 2007. The decrease in net income is primarily the result of a non-cash full cost ceiling write-down recorded in the third and fourth quarters of 2008. The full cost ceiling impairment is discussed further in the operating costs and expenses section below.

Oil and Gas Sales (In thousands or as indicated)	For the Years Ended December 31, 2008	2007	Percent Change Between 2008/2007	Price/Volume Analysis Price	Volume	Variance
Gas sales	$ 1,074,705	$ 845,631	27%	$ 175,873	$ 53,201	$ 229,074
Oil sales	806,186	518,991	55%	220,956	66,239	287,195
Total oil and gas sales	$ 1,880,891	$ 1,364,622	38%	$ 396,829	$ 119,440	$ 516,269
Total gas volume MMcf	127,444	119,937	6%			
Gas volume MMcf per day	348.2	328.6				
Average gas price per Mcf	$ 8.43	$ 7.05	20%			
Effect of hedges per Mcf	$ 0.09	$ 0.23				
Total oil volume thousand barrels	8,395	7,445	13%			
Oil volume barrels per day	22,937	20,399				
Average oil price per barrel	$ 96.03	$ 69.71	38%			

Oil and gas sales during 2008 totaled $1.9 billion, compared to $1.4 billion in 2007. Of the $516.3 million increase in sales between the two periods, $396.8 million related to higher prices and $119.4 million resulted from higher production volumes.

Compared to 2007, our 2008 oil production increased by 13% to an average of 22,937 barrels per day in 2008. This increase resulted in $66.2 million of incremental revenues. Gas volumes averaged 348.2 MMcf per day in 2008 compared to 328.6 MMcf per day in 2007, resulting in an increase in revenues of $53.2 million. Total 2008 oil and gas production volumes were 485.8 MMcfe per day, up 34.8 MMcfe per day from 2007. Both our gas and oil volumes increased as 2008 unfolded. During the fourth quarter of 2008, our gas production averaged 350.3 MMcf per day up from 341.1 MMcf per day (a three percent increase) in the fourth quarter of 2007. Fourth quarter oil production increased by 10% to 23,907 barrels per day, up from 21,680 barrels per day in 2007.

Average realized gas prices increased by 20% to $8.43 per Mcf in 2008, compared to $7.05 per Mcf for 2007. This price increase boosted gas sales by $175.9 million between the two periods. Included in our 2008 realized gas price is $11.3 million of cash receipts (a positive $0.09 per Mcf effect) from settlement of cash flow hedges on 40,000 MMBtu per day of Mid-Continent gas production.

Realized oil prices averaged $96.03 per barrel during 2008, compared to $69.71 per barrel in 2007. The increase in oil sales resulting from this 38% improvement in oil prices totaled $221.0 million.

Table of Contents

Changes in realized gas and oil prices were mostly the result of overall market conditions and our modest gas hedging program.

	For the Years Ended December 31,	
	2008	2007
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering, processing and other revenues	$ 87,757	$ 60,818
Gas gathering and processing costs	(43,838)	(29,860)
Gas gathering and processing margin	$ 43,919	$ 30,958
Gas marketing revenues, net of related costs	$ 1,699	$ 5,073

We sometimes transport, process and market third-party gas that is associated with our gas. In 2008, third-party gas gathering and processing contributed $43.9 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $31 million in 2007. Our gas marketing margin (revenues less purchases) decreased to $1.7 million in 2008 from $5.1 million in 2007. Changes in net margins from gas gathering, processing and marketing activities are the direct result of changes in volumes and overall market conditions.

	For the Years Ended December 31,		Variance Between
	2008	2007	2008/2007
Operating costs and expenses (in thousands):			
Impairment of oil and gas properties	$ 2,242,921	$	$ 2,242,921
Depreciation, depletion and amortization	547,404	461,791	85,613
Asset retirement obligation	8,796	8,937	(141)
Production	218,736	201,512	17,224
Transportation	38,107	26,361	11,746
Taxes other than income	130,490	93,630	36,860
General and administrative	44,500	49,260	(4,760)
Stock compensation, net	10,090	10,772	(682)
Other operating, net	126,433	6,637	119,796
	$ 3,367,477	$ 858,900	$ 2,508,577

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) increased to $3,367.5 million in 2008 compared to $858.9 million in 2007.

The largest component of the increase between periods is the non-cash impairment of oil and gas properties in the amount of $2.2 billion ($1.4 billion, net of tax) that was recorded as a result of declines in natural gas and oil prices during the last half of 2008. At September 30, 2008, our ceiling limitation calculation resulted in excess capitalized costs of $657.1 million ($417.4 million, net of tax), for which we recorded a non-cash impairment of oil and gas properties. As a result of further declines in natural gas and oil prices during the fourth quarter of 2008, we recorded an additional non-cash impairment of oil and gas properties. Electing to use period end prices, at December 31, 2008, our ceiling limitation calculation resulted in excess capitalized costs of $1.6 billion ($1.0 billion after tax). Due to the volatility of oil and gas prices and because the ceiling calculation requires that prices in effect as of the last day of the period be held constant in valuing proved reserves, we may be required to record a ceiling test write-down in future periods. The full cost method of accounting is discussed in detail under "Critical Accounting Policies and Estimates".

DD&A increased $85.6 million between periods from $461.8 million in 2007 to $547.4 million in 2008. On a unit of production basis, DD&A was $3.08 per Mcfe in 2008 compared to $2.81 per Mcfe for 2007.

Table of Contents

The increase stems from replacement costs for reserves added being higher than costs of reserves produced. Service costs to drill and complete wells have been increasing and we are drilling deeper and more complex wells. Additionally, the significant decrease in oil and gas prices over the last half of 2008 reduced the amount of our estimated reserve quantities (future production), causing an increase in our depletion rate. Due to the reduction to the carrying value of oil and gas properties recorded at year end we expect the DD&A rate to be lower in the first quarter of 2009 in comparison to the full year 2008.

Production costs rose $17.2 million, or nine percent, from $201.5 million ($1.22 per Mcfe) in 2007 to $218.7 million ($1.23 per Mcfe) in 2008. This increase resulted from an eight percent increase in production volumes and a $7.4 million increase in workover expense between periods.

Transportation costs increased from $26.4 million in 2007 to $38.1 million in 2008. The increase is the result of higher sales volumes, increased market rates and a higher fuel cost component due to higher natural gas prices during the year.

Taxes other than income were $36.9 million greater, rising from $93.6 million in 2007 to $130.5 million in 2008. The increase between periods resulted from increases in oil and gas sales stemming from higher production volumes and commodity prices.

General and administrative (G&A) expenses decreased $4.8 million from $49.3 million in 2007 to $44.5 million in 2008. The decrease between periods is due to lower employee-benefit costs due to a decrease in bonus and profit sharing expenses resulting from significant decreases in commodity prices during the last quarter of 2008.

In 2008, the increase in Other operating, net to $126.4 million from $6.6 million was primarily related to the Tulsa County District Court issuing a judgment in the H.B. Krug case. The total accrued litigation expense for the year ended December 31, 2008 for this lawsuit is $119.6 million. We have appealed the District Court's judgments. For further information on this lawsuit and other litigation please see Contingencies under "Critical Accounting Policies and Estimates".

Other income and expense

Interest expense decreased by $6.0 million, or 15%, primarily because of a decrease in our average bank debt outstanding during the year. In addition, in comparison to prior year, we experienced a decrease in our average interest rate on both our bank borrowings and convertible notes. Capitalized interest increased by $2.4 million mainly because we had more costs incurred to develop our unproved properties than we had in 2007. We also had a loss on the repurchase of convertible notes of $10.1 million compared to a $5.1 million gain in 2007 on the early extinguishment of debt arising from redemption of our $195 million face value of 9.6% senior unsecured notes.

Other, net decreased from $14.2 million of income in 2007 to $10.3 million of income in 2008. Components consist of miscellaneous income and expense items that will vary from period to period, including income and loss in equity investees, gain or loss on sale or value of oil and gas well equipment and interest income. Included in our 2008 Other, net is $16.0 million of impairment expense on our equity investments and $0.8 million of impairment on our short-term investments. These additional expenses were offset by a $17.2 million increase in gain on sale of oil and gas well equipment in comparison to 2007. Another element of the decrease between periods is lower income of $4.2 million from equity investees.

Income tax

During 2008, a net deferred income tax benefit of $536.4 million was recognized (the year end deferred tax benefit included $66.2 million of income tax expense). This compares with 2007 current taxes of $30.6 million and deferred income tax expense of $166.8 million. The combined Federal and state effective income tax rates were 37.0% and 36.4% in the years of 2008 and 2007, respectively. The effective tax rate of 37.0% for 2008 differs from the statutory rate due to effects of the domestic production activities deduction and percentage depletion.

LIQUIDITY AND CAPITAL RESOURCES

Overview

The ongoing global economic slowdown has continued to impact commodity prices. Though prices improved as 2009 unfolded, they remained substantially below prior year levels. Volatility in commodity prices may reduce the amount of oil and gas that we can economically produce. Commodity prices also affect the amount of cash flow available for capital expenditures as well as our ability to borrow and raise additional capital. These conditions could impact third parties with whom we do business, causing them to fail to meet their obligations to us.

We have and will continue to focus on maintaining liquidity and low financial leverage. Historically our exploration and development expenditures have generally been funded by cash flow provided by operating activities ("operating cash flow"). In 2010 we intend to continue to fund our exploration and development expenditures with operating cash flow.

We will also continue to consider attractive acquisition opportunities. However, the timing and size of acquisitions is unpredictable. To ready ourselves for potential acquisitions and possible further declines in commodity prices, we entered into a new three-year senior secured revolving credit facility in April 2009. The new facility increased bank commitments from $500 million to $800 million. The borrowing base is $1 billion.

We believe that our operating cash flow and other capital resources will be adequate to continue to meet our needs for our planned capital expenditures, working capital, debt servicing, and dividend payments for 2010 and beyond.

Sources and Uses of Cash

Our primary sources of liquidity and capital resources are cash flow from operating activities, occasional property sales, borrowings under our bank credit facility and public offerings of debt securities. Our primary uses of funds are exploration and development, property acquisitions, common stock dividends and occasional share repurchases.

Table of Contents

The following table presents the sources and uses of our cash and cash equivalents from 2007 to 2009. The table presents capital expenditures on a cash basis. These amounts differ from the amounts of capital expenditures (including accruals) that are referred to elsewhere in this document.

	For the Years Ended December 31,		
	2009	**2008**	**2007**
		(in thousands)	
Sources of cash and cash equivalents:			
Operating cash flow	$ 675,177	$ 1,367,488	$ 994,680
Proceeds from sale of assets	119,735	39,096	177,195
Net increase in bank debt		220,000	
Distributions from equity investees		39	3,015
Sales of short-term investments	3,328	10,679	1,424
Increase in other long-term debt			350,000
Proceeds from issuance of common stock and other	3,421	13,141	9,886
Total sources of cash and cash equivalents	801,661	1,650,443	1,536,200
Uses of cash and cash equivalents:			
Oil and gas expenditures	(535,308)	(1,594,775)	(1,021,456)
Purchase of short-term investments			(16,000)
Other expenditures	(31,849)	(51,757)	(19,574)
Net decrease in bank debt	(195,000)		(95,000)
Decrease in other long-term debt		(105,550)	(204,360)
Financing costs incurred	(18,001)	(158)	(6,113)
Treasury stock acquired and retired			(42,266)
Dividends paid	(20,172)	(20,040)	(13,429)
Total uses of cash and cash equivalents	(800,330)	(1,772,280)	(1,418,198)
Net increase (decrease) in cash and cash equivalents	$ 1,331	$ (121,837)	$ 118,002
Cash and cash equivalents at end of year	$ 2,544	$ 1,213	$ 123,050

Analysis of Cash Flow Changes (See the Consolidated Statements of Cash Flows)

Cash flow provided by operating activities for 2009 was $675.2 million, compared to $1,367.5 million for 2008 and $994.7 million for 2007. The decrease from 2008 to 2009 resulted primarily from lower gas and oil prices and decreased gas production. The increase from 2007 to 2008 resulted primarily from higher gas prices, high oil prices and increased production.

Cash flow used in investing activities for 2009 was $444 million, compared to $1.6 billion for 2008 and $875.4 million for 2007. Changes in the cash flow used in investing activities are generally the result of changes in our exploration and development programs, acquisitions and property sales. The decrease from 2008 to 2009 was mostly caused by decreased oil and gas expenditures. In response to the lower oil and gas prices at the end of 2008, we significantly reduced our planned 2009 capital expenditures from our record high in 2008. The increase from 2007 to 2008 was caused by increased oil and gas expenditures resulting from a more active drilling program. In addition, we had $138.1 million less proceeds from sales of assets in 2008 when compared to 2007.

Net cash flow used in financing activities in 2009 was $229.8 million versus net cash flow provided by financing activities of $107.4 million in 2008. In 2009 we had net payments on our credit facility of $195 million and $18 million of financing costs for the new three-year senior secured revolving credit facility. In 2008 we had borrowings under our credit facility of $220.0 million and $13.1 million in proceeds from issuance of common stock and other. Also in 2008 we used $105.6 million of the borrowings under our credit facility to repurchase a portion of our convertible notes in December. We made dividend payments of approximately $20.0 million in both 2009 and 2008.

Net cash flow used in financing activities in 2007 was $1.3 million. Two significant uses were for share repurchases of $42.3 million and $13.4 million for dividends. Proceeds from our May 2007 issuance of $350 million of ten-year, 7.125% senior unsecured notes were used to redeem our old 9.6% notes and reduce outstanding borrowings under our credit facility.

Capital Expenditures

The following table sets forth certain historical information regarding capitalized expenditures by us in our oil and gas acquisition, exploration, and development activities (in thousands):

	For Years Ended December 31,		
	2009	**2008**	**2007**
Acquisitions:			
Proved	$ 13,530	$ 6,618	$ 17,334
Unproved	(9,915)*	175,777	23,580
	3,615	182,395	40,914
Exploration and development:			
Land & seismic	48,466	157,403	98,162
Exploration	45,603	245,538	217,696
Development	430,357	1,035,442	666,662
	524,426	1,438,383	982,520
Property sales	(109,408)	(38,093)	(176,659)
	$ 418,633	$ 1,582,685	$ 846,775

* The negative balance reflects purchase price adjustments related to an acreage acquisition in the fourth quarter of 2008.

Our exploration and development expenditures decreased 64 percent in 2009 compared to 2008. The decrease in 2009 resulted from a planned decrease in our exploration activity in response to the economic environment and our continued efforts to operate within our cash flow provided by operating activities. Overall, we drilled and completed 110 gross (67 net) wells during 2009 versus 450 gross (277 net) wells in 2008. At year-end 2009 an additional 11 gross (6.3 net) Cana-Woodford wells were waiting on completion.

Our planned capital program for 2010 will range from $700-$900 million. Although our 2010 capital budget is set at a level that we believe corresponds with our anticipated 2010 cash flows, the timing of capital expenditures and the receipt of cash flows do not necessarily match. We anticipate borrowing and repaying funds under our credit arrangements throughout the year. If we start to see a significant change in commodity prices from our current forecasts, we have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

We have made, and will continue to make, expenditures to comply with environmental and safety regulations and requirements. These costs are considered a normal recurring cost of our ongoing operations and not an extraordinary cost of compliance. We do not anticipate that we will be required to expend amounts that will have a material adverse effect on our financial position or operations, nor are we aware of any pending regulatory changes that would have a material impact

Our 2009 exploration and development drilling program is discussed in more detail in *Exploration and Development Activity Overview* under Item 1 of this Form 10-K.

41

Table of Contents

Financial Condition

Future cash flows and the availability of financing will be subject to a number of variables, such as our success in locating and producing new reserves, the level of production from existing wells and prices of oil and natural gas. To meet our capital and liquidity requirements, we rely on certain resources, including cash flows from operating activities, access to capital markets, and bank borrowings. While we attempt to operate within forecasted cash flows from operations, we do periodically access our credit facility to finance our working capital needs and growth.

During 2009 our total assets, net oil and gas assets, net income and stockholders' equity were reduced by a non-cash impairment of oil and gas properties in the amount of $791.1 million ($501.8 million after tax). Total assets decreased in 2009 from $4.2 billion at the beginning of the year to $3.4 billion by December 31, 2009. Our net oil and gas assets decreased by $623.6 million and our cash position increased by $1.3 million for the same period. As of December 31, 2009, stockholders' equity totaled $2.0 billion, down from $2.4 billion at December 31, 2008. The decrease resulted primarily from a current year 2009 net loss of $311.9 million.

Dividends

In December 2005, the Board of Directors declared the Company's first quarterly cash dividend of $.04 per share payable to shareholders. A dividend has been authorized in every quarter since then. On December 12, 2007 the Board of Directors increased the regular cash dividend on our common stock from $0.04 to $0.06 per common share.

Common Stock Repurchase Program

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of common stock. During 2007 we repurchased a total of 1,114,200 shares at an average purchase price of $37.93. Cumulative purchases through December 31, 2007 total 1,364,300 shares at an average price of $39.05. No purchases were made in 2009 or since the quarter ended September 30, 2007. In 2009 the Board of Directors extended the repurchase program to December 31, 2011.

Working Capital Analysis

Our working capital balance fluctuates primarily as a result of our exploration and development activities and our realized commodity prices. Working capital is also impacted by our current tax provisions, accrued G&A and changes in the fair value of our outstanding derivative instruments.

At December 31, 2009, we had positive working capital of $18.5 million, down $26.9 million from year-end 2008. Working capital decreased primarily because of the following:

- Changes related to our current income tax provisions, including receipt of tax refunds, resulted in net decreases of $67.3 million.
- Decreases associated with oil and gas well equipment and supplies were $40.9 million.
- An increase of $16.1 million related to 2009 bonus accruals.
- A net decrease of $12.7 million in the fair value of our outstanding derivative instruments.
- A net decrease of $20 million of various other current assets and liabilities, including a net decrease of $7.2 million in outstanding advances.

These working capital decreases were mostly offset by:

$97.2 million of lower payables and receivables related to our reduced exploration and development activities in 2009.

Table of Contents

$33.4 million related to the improvement in commodity prices, particularly in the fourth quarter of 2009.

Financing

Debt at December 31, 2009 and 2008 consisted of the following (in thousands):

	2009	2008
Bank debt	$ 25,000	$ 220,000
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023 (face value $19,450)	17,793	17,630
Total long-term debt	$ 392,793	$ 587,630

Bank Debt

In April 2009, we entered into a new three-year senior secured revolving credit facility ("credit facility"). The new credit facility increased bank commitments from $500 million to $800 million, with a borrowing base of $1 billion. The credit facility is provided by a syndicate of banks led by JP Morgan Chase Bank, N.A., matures on April 14, 2012 and is secured by mortgages on certain of our oil and gas properties and the stock of certain wholly-owned operating subsidiaries.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations.

The credit facility contains covenants and restrictive provisions which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility requires us to maintain a current ratio (defined to include undrawn borrowings) greater than 1 to 1 and a leverage ratio not to exceed 3.5 to 1. As of December 31, 2009, we were in compliance with all of the financial and non-financial covenants.

At Cimarex's option, borrowings under the credit facility may bear interest at either (a) a London Interbank Offered Rate ("LIBOR") plus 2 to 3 percent, based on borrowing base usage, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50 percent, or (iii) adjusted LIBOR, in each case, plus an additional 1.125 to 2.125 percent, based on borrowing base usage.

At December 31, 2009, there was $25 million of borrowings outstanding under the credit facility at a weighted average interest rate of approximately 2.2%. We also had letters of credit outstanding of $16.7 million leaving an unused borrowing availability of $758.3 million.

7.125% Notes due 2017

In May, 2007, we issued $350 million of 7.125% senior unsecured notes that mature May 1, 2017 at par. Interest on the notes is payable May 1 and November 1 of each year. The notes are governed by an indenture containing covenants that could limit our ability to incur additional indebtedness; pay dividends or repurchase our common stock; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets.

Table of Contents

The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 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
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

At any time prior to May 1, 2010, we may redeem up to 35% of the original principal amount of the notes with the proceeds of certain equity offerings of our shares of common stock at a redemption price of 107.125% of the principal amount of the notes, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price of 100% of the principal amount of the notes plus accrued and unpaid interest plus a "make-whole" premium.

If a specified change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the purchase.

Floating rate convertible notes due 2023

The floating rate convertible senior notes mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On December 31, 2009, the interest rate approximated 0.3%.

In December 2008, holders of $105.5 million of the original $125 million issuance amount elected to submit their notes for repurchase. We repurchased the $105.5 million in notes with borrowings under our credit facility. Holders of the remaining $19.5 million of notes have optional repurchase dates as of December 15, 2013, and 2018.

In addition to the repurchase rights, 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 110% of the conversion price of $28.59 per share for a defined period of time. As of December 31, 2008, the notes were not convertible. However, based on the price of our common stock, the notes became convertible effective October 1, 2009 and continue to be convertible through the first quarter of 2010.

At our option, we may offer to redeem the notes at any time at par. In addition, if a change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes.

In May 2008, the FASB issued new guidance that changed the accounting for the components of convertible debt that can be settled wholly or partly in cash upon conversion. The new requirements were required to be applied to both new instruments and retrospectively to previously issued convertible instruments. The debt and equity components of the instruments are accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as of the issuance date, with the remaining proceeds allocated to the equity component and recorded as additional paid-in capital. The debt component is recorded at a discount and is subsequently accreted to its par value, thereby reflecting an overall market rate of interest in the income statement. The effective interest rate for the years ended December 31, 2009, 2008 and 2007 was 2.0%, 4.4% and 7.1%, respectively. See Note 7 for a comparison of certain financial statement line items affected by the retrospective application of this guidance.

Table of Contents

Contractual Obligations and Material Commitments

At December 31, 2009, we had contractual obligations and material commitments as follows:

		Payments Due by Period			
Contractual obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
			(In thousands)		
Long-term debt(1)	$ 394,450	$	$ 25,000	$	$ 369,450
Fixed-Rate interest payments(1)	187,031	24,938	49,875	49,875	62,343
Operating leases	20,994	5,092	9,588	6,032	282
Drilling commitments(2)	123,604	93,916	29,688		
Purchase commitments(3)	11,051	11,051			
Gas processing facility(4)	96,235	41,707	29,832	24,696	
Derivatives	13,902	13,902			
Asset retirement obligation	149,310	19,525	(5)	(5)	(5)
Other liabilities(6)	49,284	10,196	20,030	10,030	9,028

(1) These amounts do not include interest on the $25 million of bank debt outstanding at December 31, 2009. The weighted average interest rate at December 31, 2009 was approximately 2.24%. See item 7A: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) We have drilling commitments of approximately $72.9 million consisting of obligations to complete drilling wells in progress at December 31, 2009. We also have minimum expenditure commitments of $50.7 million to secure the use of drilling rigs.

(3) At December 31, 2009, we have a purchase commitment of $11.1 million for construction of an aircraft. The total cost of the aircraft is $12.3 million with an option to trade in our existing aircraft. The completion of the aircraft is expected to be no later than October 30, 2010.

(4) We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At December 31, 2009, we had commitments of $151.2 million relating to construction of the gas processing plant of which $96.2 million is subject to a construction contract. The total cost of the project will approximate $345 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

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

(6) Other liabilities include the fair value of our liabilities associated with our benefit obligations and other miscellaneous commitments.

At December 31, 2009, we had firm sales contracts to deliver approximately 1.9 Bcf of natural gas over the next three months. If this gas is not delivered, our financial commitment would be approximately $11.1 million. This commitment may fluctuate due to either price volatility or volumes delivered. However, we do not anticipate that a financial commitment will be due.

In connection with a gas gathering and processing agreement, we have commitments to deliver 55.7 Bcf of gas over the next four years. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $41.6 million, some of which will be reimbursed by working interest owners who are selling with us under our marketing agreement.

Table of Contents

We have 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 $4.7 million, some of which will be reimbursed by working interest owners who are selling with us under our marketing agreements.

All of the noted 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 bank credit facility will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and planned exploration and development activities.

2010 Outlook

Our exploration and development expenditures program for 2010 are projected to range from $700 million to $900 million. Though there are a variety of factors that could curtail, delay or even cancel some of our planned operations, we believe our projected program is likely to occur. The majority of projects are in hand, drilling rigs are being scheduled, and the historical results of our drilling efforts warrant pursuit of the projects. It is also possible that we may increase our level of planned capital investment if our oil and gas prices exceed our current expectation or if attractive new opportunities arise.

Production estimates for 2010 range from 540 to 570 MMcfe per day. Revenues from production will be dependent not only on the level of oil and gas actually produced, but also the prices that will be realized. During 2009, our realized prices averaged $4.12 per Mcf of gas and $56.13 per barrel of oil. Prices can be very volatile and the possibility of 2010 realized prices varying from prices in 2009 is high.

Certain expenses for 2010 on a per Mcfe basis are currently estimated as follows:

	2010
Production expense	$0.90 - $1.10
Transportation expense	0.19 - 0.24
DD&A and asset retirement obligation	1.50 - 1.80
General and administrative	0.24 - 0.30
Production taxes (% of oil and gas revenue)	7.5% - 8.5%

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. A complete list of our significant accounting policies are described in Note 3 to our Consolidated Financial Statements included in this report. 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 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 to be our most critical accounting policies and estimates that involve significant judgments and discuss the selection and development of these policies and estimates with our Audit Committee.

Table of Contents

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. Estimations of proved undeveloped reserves can be subject to an even greater possibility of revision. At year-end, 23 percent of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 61 percent are related to a project in Wyoming and 33 percent are from the Western Oklahoma, Cana-Woodford shale play. Our reserve engineers review and revise our reserve estimates regularly as new information becomes available. Additionally, we annually engage an independent petroleum engineering firm to review our proved reserve estimates associated with at least 80 percent of the discounted future net cash flows before income taxes. As further discussed in *Recently Issued Accounting Standards*, the SEC and FASB amended oil and gas reporting requirements effective December 31, 2009. The impact to Cimarex was minimal, apart from the change to a new standard using 12 month average pricing rather than prices in effect at the end of a period.

We use the units-of-production method to amortize our oil and gas properties. For depletion purposes, reserve quantities are adjusted at interim quarterly periods for the estimated impact of additions, dispositions and price changes. Changes in reserve quantities cause corresponding changes in depletion expense in periods subsequent to the quantity revision. It is also possible that a full cost ceiling limitation charge could occur in the period of the revision.

The following table presents information regarding reserve revisions largely resulting from items we do not control, such as revisions due to price, and other revisions resulting from better information due to production history, well performance and changes in production costs.

	Years Ended December 31,					
	2009		**2008**		**2007**	
	Bcfe Change	**Percent of total Reserves**	**Bcfe Change**	**Percent of total Reserves**	**Bcfe Change**	**Percent of total Reserves**
Revisions resulting from price changes	(30.8)	(2.30)%	(145.2)	(9.86)%	35.5	2.45%
Other changes in estimates	104.7	7.82%	(11.6)	(0.79)%	22.0	1.52%
Total	73.9	5.52%	(156.8)	(10.65)%	57.5	3.97%

Non-price related revisions added 115.1 Bcfe over the three-year period 2007-2009. Over the same period we have seen a 140.5 Bcfe decrease resulting from lower prices. See Note 17, Unaudited Supplemental Oil and Gas Disclosures for additional reserve data.

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. In addition, gains or losses on the sale or other disposition of oil and gas properties are not recognized in earnings unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to our full cost pool.

At the end of each quarter, we make a full cost ceiling limitation calculation, whereby net capitalized costs related to proved properties less associated deferred income taxes may not exceed the amount of 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 have previously been determined based on current oil and gas prices adjusted for designated cash flow hedges. For year-end 2009, new SEC rules were implemented requiring reserve calculations to be based on the unweighted average first-day-of-the-month prices for the prior twelve months. Changes in proved reserve estimates (whether based upon quantity revisions or oil and gas prices) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be charged to expense. Any recorded impairment of oil and gas properties is not reversible at a later date.

Due to a significant decrease in period end commodity prices, at September 30, 2008, our ceiling limitation calculation resulted in excess capitalized costs of $657.1 million ($417.4 million, net of tax), for which we recorded a non-cash impairment of oil and gas properties. As a result of further declines in natural gas and oil prices, we recorded additional non-cash impairments of oil and gas properties of $1.6 billion ($1.0 billion after tax) in the fourth quarter of 2008, and $791.1 million ($501.8 million after tax) in the first quarter of 2009. The Company's quarterly and annual ceiling test has been primarily impacted by commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. Holding all factors constant other than commodity prices, a 10% decline in prices as of December 31, 2009 would not have resulted in a ceiling test impairment. Changes in actual reserve quantities added and produced along with our actual overall exploration and development costs will determine the Company's actual ceiling test calculation and impairment analyses. Decreases in commodity prices can also impact our goodwill impairment analyses.

Goodwill

At December 31, 2009, we had $691.4 million of goodwill recorded in conjunction with past business combinations. Goodwill is subject to annual reviews for impairment based on a two step accounting test. The first step is to compare the estimated fair value of the Company with the recorded net book value (including the goodwill), after giving effect to all other period impairments, including the impairment of oil and gas properties from the full cost pool ceiling limitation calculation. If the estimated fair value is higher than the recorded net book value, no impairment is deemed to exist and no further testing is required. If, however, the estimated fair value is below the recorded net book value, then a second step must be performed to determine the goodwill impairment required, if any. In this second step, a hypothetical acquisition value of the Company is computed utilizing purchase business combination accounting rules.

We perform our annual goodwill impairment review in the fourth quarter of each year. Management must apply judgment in determining the estimated fair value of the Company for purposes of performing the annual goodwill impairment test. As of December 31, 2009, the market price per share of our common stock was greater than the book value by $28 per share. Due to volatility in the stock markets, management does not consider the market value of our shares to be an accurate reflection of our net assets for impairment purposes. To estimate the fair value of the Company, we use all available information, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets. This estimated fair value differs significantly from the valuation used in the ceiling limitation calculation which requires that prices and costs be held constant over the life of the wells and are discounted at 10 percent. The ceiling calculation is not intended to be indicative of fair value.

In estimating the fair value of our oil and gas properties for our goodwill impairment analysis, we used projected future prices based on the NYMEX strip index at December 31, 2009 (adjusted for estimated delivery point price differentials). As of December 31, 2009, the fair value exceeds the carrying value of our net assets. Should lower prices or quantities result in the future, or higher discount rates be necessary, the carrying value of our net assets may exceed the estimated fair value, resulting in an impairment of goodwill.

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.

In January, 2009, the Tulsa County District Court issued a judgment in the H.B. Krug, et al versus Helmerich & Payne, Inc. ("H&P") case. This lawsuit was originally filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. Damages of $6.9 million, plus $119.5 million for disgorgement of H&P's estimated potential compounded profit since 1989 resulting from the noted damages, were awarded to plaintiff royalty owners for a total of $126.4 million. This amount was subsequently adjusted by the court to a total of $119.6 million. Pursuant to the 2002 spin-off transaction to shareholders of H&P by which Cimarex became a publicly traded entity, Cimarex assumed the assets and liabilities of H&P's exploration and production business. In 2008 we had accrued litigation expense of $119.6 million for this lawsuit. During 2009, we have accrued an additional $9.4 million. We have appealed the District Court's judgments.

In the normal course of business, we have other various litigation related matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. For the year 2009, we had approximately $10.0 million of such expenses. Though some of the related claims may be significant, the resolution of them we believe, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations.

Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable state laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. For example, as we analyze actual plugging and abandonment information, we may revise our estimates of current costs, the assumed annual inflation of these costs and/or the assumed productive lives of our wells. During 2009, we revised our existing estimated asset retirement obligation by $13.4 million, or approximately nine percent of the asset retirement obligation at December 31, 2009, due to changes in the various related attributes. Over the past three years, revisions to the estimated asset retirement obligation averaged approximately 9.5 percent. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to

Table of Contents

depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

Recently Issued Accounting Standards

In December 2008, the SEC adopted revisions to its required oil and gas reporting disclosures. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. In addition, the amendments concurrently align the SEC's full cost accounting rules with the revised disclosures. The revised disclosure requirements must be incorporated in registration statements filed on or after January 1, 2010, and annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

The following amendments have the greatest likelihood of affecting our reserve disclosures:

Pricing mechanism for oil and gas reserves estimation The SEC's prior rules required proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. Price changes can be made only to the extent provided by contractual arrangements. The revised rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price will also be used for purposes of calculating the full cost ceiling limitations. Price changes can still be incorporated to the extent defined by contractual arrangements. The use of a 12-month average price rather than a single-day price is expected to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

Reasonable certainty The SEC's prior definition of "proved oil and gas reserves" incorporate certain specific concepts such as "lowest known hydrocarbons," which limits the ability to claim proved reserves in the absence of information on fluid contacts in a well penetration, notwithstanding the existence of other engineering and geoscientific evidence. The revised rules amend the definition to permit the use of reliable technologies to establish the reasonable certainty of proved reserves. This revision also includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations.

The revised rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. These revisions are designed to permit the use of alternative technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells. Because the revised rules generally expand the definition of proved reserves, proved reserve estimates could increase in the future based upon adoption of the revised rules.

Unproved reserves The SEC's prior rules prohibited disclosure of reserve estimates other than proved in documents filed with the SEC. The revised rules permit disclosure of probable and possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and possible reserves is optional. However, such disclosures must meet specific requirements. Disclosures of probable or possible reserves must provide the same level of geographic detail as proved reserves. Probable and possible reserve disclosures must also provide disclosure of the relative uncertainty associated with these classifications of reserves estimations.

Table of Contents

In June 2009, the FASB approved the FASB Accounting Standards Codification (ASC), which after its launch on July 1, 2009 became the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The Codification reorganizes all previous U.S. GAAP pronouncements into roughly 90 accounting topics and displays all topics using a consistent structure. All existing standards that were used to create the Codification are now superseded, replacing the previous references to specific Statements of Financial Accounting Standards with numbers used in the Codification's structural organization.

In January 2010, the FASB issued an Accounting Standards Update (ASU) 2010-03, *Extractive Industries-Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosure.* This ASU amends the FASB accounting standards to align the reserve calculation and disclosure requirements with the requirements in the new SEC Rule, *Modernization of Oil and Gas Reporting Requirements*. The ASU is effective for reporting periods ending on or after December 31, 2009.

ITEM 7A. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

The term "market risk" refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Price Fluctuations

Our major market risk is pricing applicable to our oil and gas production. The prices we receive for our production are based on prevailing market conditions and are influenced by many factors that are beyond our control. Pricing for oil and gas production has been volatile and unpredictable.

We periodically hedge a portion of our price risk associated with our future oil and gas production.

The following table details the contracts we have in place as of December 31, 2009:

Natural Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Weighted Average Price Swap	Fair Value (000's)
Jan 10 - Dec 10	Collar	100,000 MMBtu	PEPL	$ 5.00	$ 6.62		$ 2,228
Jan 10 - Dec 10	Swap	40,000 MMBtu	PEPL			$ 5.18	$ (5,289)
Jan 10 - Dec 10	Collar	20,000 MMBtu	HSC	$ 5.00	$ 6.85		$ (10)

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000's)
Jan 10 - Dec 10	Collar	10,000 Bbls	WTI	$ 60.03	$ 92.07	$ (10,164)
Jan 10 - Dec 10	Put/Floor	1,000 Bbls	WTI	$ 60.00		570

(1) PEPL refers to Panhandle Eastern Pipe Line Company price and HSC refers to Houston Ship Channel price, both as quoted in Platt's Inside FERC on the first business day of each month. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the 2010 contracts listed above, a hypothetical $0.10 change in the price below or above the contracted price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2010 of $8.2 million.

Table of Contents

In spite of the recent turmoil in the financial markets, counterparty credit risk did not have a significant effect on our cash flow calculations and commodity derivative valuations. This is primarily the result of two factors. First, we have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Our commodity derivative contracts are held with eight separate counterparties. Second, our derivative contracts are held with "investment grade" counterparties that are a part of our credit facility. See Note 4 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Interest Rate Risk

At December 31, 2009, our debt was comprised of the following (in thousands):

	Fixed Rate Debt	Variable Rate Debt
Bank debt	$	$ 25,000
7.125% Notes due 2017	350,000	
Floating rate convertible notes due 2023 (face value $19,450)		17,793
Total long-term debt	$ 350,000	$ 42,793

As of December 31, 2009, the amounts outstanding under our senior secured revolving credit facility bears interest at either (a) a LIBOR plus 2 to 3 percent, based on borrowing base usage, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50 percent, or (iii) adjusted LIBOR, in each case, plus an additional 1.125 to 2.125 percent, based on borrowing base usage. Our senior unsecured notes bear interest at a fixed rate of 7.125% and will mature on May 1, 2017, and our unsecured convertible senior notes bear interest at an annual rate of three-month LIBOR, reset quarterly.

We consider our interest rate exposure to be minimal because approximately 89% of our long-term debt obligations were at fixed rates. An increase of 100 basis points in the three-month LIBOR rate would increase our annual interest expense by $445,000. This sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 5 and Note 7 to the Consolidated Financial Statements in this report for additional information regarding debt.

Table of Contents

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.

Table of Contents

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 (the Company) as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in notes 7 and 10 to the consolidated financial statements, Cimarex Energy Co. changed its accounting for its convertible debt instrument that may be settled in cash upon conversion (including partial cash settlement) and began computing earnings per share using the two-class earnings allocation method, effective January 1, 2009, which have been applied retrospectively in the consolidated financial statements referred to above.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 26, 2010 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver, Colorado
February 26, 2010

Table of Contents

CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share information)

	December 31, 2009	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 2,544	$ 1,213
Restricted cash	593	502
Short-term investments		2,502
Accounts receivable:		
Trade, net of allowance	41,252	73,676
Oil and gas sales, net of allowance	176,551	136,606
Gas gathering, processing, and marketing, net of allowance	6,292	6,974
Other	3,801	41,826
Oil and gas well equipment and supplies	145,153	186,062
Deferred income taxes	15,837	2,435
Derivative instruments	1,238	
Other current assets	13,997	63,148
Total current assets	407,258	514,944
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	7,549,861	7,052,464
Unproved properties and properties under development, not being amortized	399,724	465,638
	7,949,585	7,518,102
Less accumulated depreciation, depletion and amortization	(5,764,669)	(4,709,597)
Net oil and gas properties	2,184,916	2,808,505
Fixed assets, less accumulated depreciation of $88,544 and $67,020	127,237	119,616
Goodwill	691,432	691,432
Other assets, net	33,694	30,436
	$ 3,444,537	$ 4,164,933
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 18,309	$ 89,221
Gas gathering, processing, and marketing	11,905	11,936
Accrued liabilities:		
Exploration and development	52,781	111,511
Taxes other than income	27,956	26,473
Other	155,078	126,010
Derivative instruments	13,902	
Revenue payable	108,832	104,438
Total current liabilities	388,763	469,589
Long-term debt	392,793	587,630

Deferred income taxes	348,897	500,945
Asset retirement obligation	129,785	125,338
Other liabilities	146,193	129,784
Total liabilities	1,406,431	1,813,286
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued		
Common stock, $0.01 par value, 200,000,000 shares authorized, 83,541,995 and 84,144,024 shares issued, respectively	835	841
Treasury stock, at cost, zero and 885,392 shares held, respectively		(33,344)
Paid-in capital	1,859,255	1,874,834
Retained earnings	178,035	510,271
Accumulated other comprehensive (loss) income	(19)	(955)
	2,038,106	2,351,647
	$ 3,444,537	$ 4,164,933

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	For the Years Ended December 31,		
	2009	**2008**	**2007**
Revenues:			
Gas sales	$ 485,448	$ 1,074,705	$ 845,631
Oil sales	476,995	806,186	518,991
Gas gathering, processing and other	46,763	87,757	60,818
Gas marketing, net of related costs of $68,719, $141,668 and $107,678 respectively	588	1,699	5,073
	$ 1,009,794	1,970,347	1,430,513
Costs and expenses:			
Impairment of oil and gas properties	791,137	2,242,921	
Depreciation, depletion and amortization	265,699	547,404	461,791
Asset retirement obligation	12,313	8,796	8,937
Production	178,215	218,736	201,512
Transportation	33,758	38,107	26,361
Gas gathering and processing	20,560	43,838	29,860
Taxes other than income	75,634	130,490	93,630
General and administrative	41,724	44,500	49,260
Stock compensation, net	9,254	10,090	10,772
Loss on derivative instruments, net	13,059		
Other operating, net	24,263	126,433	6,637
	1,465,616	3,411,315	888,760
Operating income (loss)	(455,822)	(1,440,968)	541,753
Other (income) and expense:			
Interest expense	39,777	33,079	39,105
Capitalized interest	(23,408)	(22,108)	(19,680)
Amortization of fair value of debt			(1,146)
(Gain) loss on early extinquishment of debt		10,058	(5,099)
Other, net	16,290	(10,348)	(14,151)
Income (loss) before income tax	(488,481)	(1,451,649)	542,724
Income tax expense (benefit)	(176,538)	(536,404)	197,462
Net income (loss)	$ (311,943)	$ (915,245)	$ 345,262
Earnings (loss) per share to common shareholders:			
Basic			
Distributed	$ 0.24	$ 0.24	$ 0.18
Undistributed	(4.06)	(11.46)	3.97
	$ (3.82)	$ (11.22)	$ 4.15
Diluted			
Distributed	$ 0.24	$ 0.24	$ 0.18
Undistributed	(4.06)	(11.46)	3.87

$	(3.82)	$	(11.22)	$	4.05

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2009	**2008**	**2007**
Cash flows from operating activities:			
Net income (loss)	$ (311,943)	$ (915,245)	$ 345,262
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairments and other valuation losses	806,039	2,259,687	2,138
Depreciation, depletion and amortization	265,699	547,404	461,791
Asset retirement obligation	12,313	8,796	8,937
Deferred income taxes	(164,760)	(602,593)	166,813
Stock compensation, net	9,254	10,090	10,772
Derivative instruments, net	14,453		
Gain on liquidation of equity investees		(39)	(3,015)
Changes in non-current assets and liabilities	8,948	119,562	(47)
Other, net	18,478	15,557	509
Changes in operating assets and liabilities			
(Increase) decrease in receivables, net	29,881	56,245	(7,777)
(Increase) decrease in oil and gas well equipment and supplies and other current assets	49,894	(155,222)	(33,917)
Increase (decrease) in accounts payable and accrued liabilities	(63,079)	23,246	43,214
Net cash provided by operating activities	675,177	1,367,488	994,680
Cash flows from investing activities:			
Oil and gas expenditures	(535,308)	(1,594,775)	(1,021,456)
Sales of oil and gas and other assets	119,735	39,096	177,195
Distributions received from equity investees		39	3,015
Purchases of short-term investments			(16,000)
Sales of short-term investments	3,328	10,679	1,424
Other expenditures	(31,849)	(51,757)	(19,574)
Net cash used by investing activities	(444,094)	(1,596,718)	(875,396)
Cash flows from financing activities:			
Net Increase (decrease) in bank debt	(195,000)	220,000	(95,000)
Increase in other long-term debt			350,000
Decrease in other long-term debt		(105,550)	(204,360)
Financing costs incurred	(18,001)	(158)	(6,113)
Treasury stock acquired and retired			(42,266)
Dividends paid	(20,172)	(20,040)	(13,429)
Issuance of common stock and other	3,421	13,141	9,886
Net cash provided by (used in) financing activities	(229,752)	107,393	(1,282)
Net change in cash and cash equivalents	1,331	(121,837)	118,002
Cash and cash equivalents at beginning of period	1,213	123,050	5,048
Cash and cash equivalents at end of period	$ 2,544	$ 1,213	$ 123,050

The accompanying notes are an integral part of these consolidated financial statements.

Table of Contents

CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Common Stock				Accumulated Other Comprehensive		
	Shares	Amount	Paid-in Capital	Retained Earnings	Income (loss)	Treasury Stock	Total Stockholders' Equity
Balance, December 31, 2006	83,962	$ 840	$ 1,886,457	$ 1,115,442	$ 31,081	$ (40,628)	$ 2,993,192
Dividends				(15,109)			(15,109)
Issuance of restricted stock awards	572	5	(5)				
Treasury Stock						(42,266)	(42,266)
Common stock reacquired and retired	(1,306)	(13)	(49,270)			42,266	(7,017)
Restricted stock forfeited and retired	(61)	(1)	1				
Amortization of unearned compensation			12,738				12,738
Exercise of stock options, net of tax benefit of $4,026 recorded in paid-in capital	454	5	9,881				9,886
Stock Option Compensation Expense			1,897				1,897
Comprehensive income:							
Net income				345,262			345,262
Net change from hedging activity					(23,302)		(23,302)
Unrealized change in short-term investments and other, net of tax					(153)		(153)
Total comprehensive income							321,807
Balance, December 31, 2007	83,621	$ 836	$ 1,861,699	$ 1,445,595	$ 7,626	$ (40,628)	$ 3,275,128
Dividends				(20,079)			(20,079)
Issuance of restricted stock awards	465	5	(5)				
Retirement of treasury stock	(193)	(2)	(7,282)			7,284	
Common stock reacquired and retired	(154)	(1)	(9,938)				(9,939)
Restricted stock forfeited and retired	(54)	(1)	1				
Amortization of unearned compensation			15,491				15,491
Exercise of stock options, net of tax benefit of $6,712 recorded in paid-in capital	414	4	13,137				13,141
Stock Option Compensation Expense			1,731				1,731
Vesting of restricted stock units	45						
Comprehensive (loss):							
Net (loss)				(915,245)			(915,245)
Net change from hedging activity					(7,652)		(7,652)
Unrealized change in short-term investments and other, net of tax					(929)		(929)
Total comprehensive (loss)							(923,826)
Balance, December 31, 2008	84,144	$ 841	$ 1,874,834	$ 510,271	$ (955)	$ (33,344)	$ 2,351,647
Dividends				(20,293)			(20,293)
Issuance of restricted stock awards	381	4	(4)				
Retirement of treasury stock	(885)	(9)	(33,335)			33,344	
Common stock reacquired and retired	(78)		(2,440)				(2,440)
Restricted stock forfeited and retired	(159)	(2)	2				
Amortization of unearned compensation			13,404				13,404
Exercise of stock options, net of tax benefit of $1,208 recorded in paid-in capital	134	1	3,420				3,421
Stock Option Compensation Expense			3,374				3,374

Vesting of restricted stock units	5						
Comprehensive (loss):							
Net (loss)				(311,943)			(311,943)
Unrealized change in short-term investments and other, net of tax					936		936
Total comprehensive (loss)							(311,007)
Balance, December 31, 2009	83,542	$ 835	$ 1,859,255	$ 178,035	$ (19)	$	$ 2,038,106

The accompanying notes are an integral part of these consolidated financial statements.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Cimarex was formed in February 2002 as a wholly-owned subsidiary of Helmerich & Payne, Inc. (H&P). On September 30, 2002, Cimarex was spun-off and became a stand-alone company. Also on September 30, 2002, Cimarex acquired 100% of the outstanding common stock of Key Production Company, Inc. (Key) in a tax-free exchange.

In June of 2005, we acquired Magnum Hunter Resources, Inc. in a stock-for-stock merger. Magnum Hunter's results of operations are included in our consolidated statements of operations beginning June 7, 2005.

The accounts of Cimarex and its subsidiaries are presented in the accompanying Consolidated Financial Statements. All intercompany accounts and transactions were eliminated in consolidation.

Our Consolidated Financial Statements 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 3 to our Consolidated Financial Statements. 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.

Certain amounts in prior years' financial statements have been reclassified to conform to the 2009 financial statement presentation. In addition, effective January 1, 2009, we adopted new rules promulgated by the Financial Accounting Standards Board (FASB) pertaining to the accounting treatment for certain convertible debt instruments (see Note 7) and to the calculation of earnings per share (see Note 10). Accordingly, prior periods have been adjusted retrospectively to conform to the applicable accounting pronouncements.

2. DESCRIPTION OF BUSINESS

Cimarex Energy Co. is an independent oil and gas exploration and production company with operations entirely located in the United States. Our oil and gas reserves and operations are mainly located in Texas, Oklahoma, New Mexico, Kansas and Wyoming. We operate wells that account for a substantial portion of our total proved reserves and production.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash, Cash Equivalents and Restricted Cash

Cash and cash equivalents consist of cash in banks and investments readily convertible into cash, which have original maturities within three months at the date of acquisition. Cash equivalents are stated at cost, which approximates market value. Restricted cash consists of monies of third parties being held by Cimarex as operator of a property in Oklahoma, until ownership disputes among the third parties are resolved.

Short-term Investments

Our short-term investments consisted of investments in an asset-backed securities fund. The investments were classified as available-for-sale and were carried at fair value in our balance sheet.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Unrealized holding gains and losses were reported in other comprehensive income (loss). We liquidated our remaining short-term investments in September, 2009.

Oil and Gas Well Equipment and Supplies

Our oil and gas well equipment and supplies are valued at the lower of cost or market using weighted average cost.

Oil and Gas Properties

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. Under the full cost method of accounting, no gain or loss is recognized upon the disposition of oil and gas properties unless such disposition would significantly alter the relationship between capitalized costs and proved reserves.

At the end of each quarter, we make a full cost ceiling limitation calculation, whereby net capitalized costs related to proved properties less associated deferred income taxes may not exceed the amount of 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 have previously been determined based on current oil and gas prices and are adjusted for designated cash flow hedges. For year-end 2009, new SEC rules were implemented requiring reserve calculations to be based on the unweighted average first-day-of-the-month prices for the prior twelve months. Changes in proved reserve estimates (whether based upon quantity revisions or oil and gas prices) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be charged to expense. Any recorded impairment of oil and gas properties is not reversible at a later date. In prior periods we used prices in effect at period end.

Due to a significant decrease in period end commodity prices in 2008 our ceiling limitation calculations resulted in excess capitalized costs of $2.2 billion ($1.4 billion, net of tax), for which we recorded a non-cash impairment of oil and gas properties. As a result of further declines in natural gas and oil prices, we recorded an additional non-cash impairment of oil and gas properties of $791.1 million ($501.8 million after tax) in the first quarter of 2009. The Company's quarterly and annual ceiling test has been primarily impacted by commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. Holding all factors constant other than commodity prices, a 10% decline in prices as of December 31, 2009 would not have resulted in a ceiling test impairment. Changes in actual reserve quantities added and produced along with our actual overall exploration and development costs will determine the Company's actual ceiling test calculation and impairment analyses. Decreases in commodity prices can also impact our goodwill impairment analyses.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, as adjusted for future development costs and asset retirement obligations, are amortized over the total estimated proved reserves. The costs of wells in progress and certain unevaluated properties

Table of Contents

are not being amortized. On a quarterly basis, we evaluate such costs for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Goodwill

At December 31, 2009, we had $691.4 million of goodwill recorded in conjunction with past business combinations. Goodwill is subject to annual reviews for impairment based on a two-step accounting test. The first step is to compare the estimated fair value of the Company with the recorded net book value (including goodwill), after giving effect to any period impairment of oil and gas properties resulting from the ceiling limitation calculation. If the estimated fair value is higher than the recorded net book value, no impairment is deemed to exist and no further testing is required. If, however, the estimated fair value is below the recorded net book value, then a second step must be performed to determine the goodwill impairment required, if any. In this second step, the estimated fair value from the first step is used as the purchase price in a hypothetical acquisition of the Company. Purchase business combination accounting rules are followed to determine a hypothetical purchase price allocation to the Company's assets and liabilities. The residual amount of goodwill that results from this hypothetical purchase price allocation is compared to the recorded amount of goodwill and the recorded amount is written down to the hypothetical amount, if lower.

We perform our annual goodwill impairment review in the fourth quarter of each year. Management must apply judgment in determining the estimated fair value of the Company for purposes of performing the annual goodwill impairment test. As of December 31, 2009, the market price per share of our common stock was greater than the book value by $28 per share. Due to volatility in the stock markets, management does not consider the market value of our shares to be an accurate reflection of our net assets for impairment purposes. To estimate the fair value of the Company, we use all available information, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets. This estimated fair value differs significantly from the valuation used in the ceiling limitation calculation which requires that prices and costs be held constant over the life of the wells and are discounted at 10 percent. The ceiling calculation is not intended to be indicative of fair value.

In estimating the fair value of our oil and gas properties for our goodwill impairment analysis, we used projected future prices based on the NYMEX strip index at December 31, 2009 (adjusted for estimated delivery point price differentials). As of December 31, 2009, the fair value exceeds the carrying value of our net assets. Should lower prices or quantities result in the future, or higher discount rates be necessary, the carrying value of our net assets may exceed the estimated fair value, resulting in an impairment of goodwill.

Revenue Recognition

Oil and Gas Sales

Revenues from oil and gas sales are based on the sales method, with revenue recognized on actual volumes sold to purchasers. There is a ready market for oil and gas, with sales occurring soon after production.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Marketing Sales

We market and sell natural gas for working interest partners under short term sales and supply agreements and earn a fee for such services. Revenues are recognized as gas is delivered and are reflected net of gas purchases on the 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, 2009 and 2008 was $4.3 million and $3.5 million, respectively. At December 31, 2009 and 2008, we were 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, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures. For 2009, positive revisions resulted from positive performance and reductions in operating costs offset by lower prices. See Note 17, Unaudited Supplemental Oil and Gas Disclosures for more reserve information. Estimations of proved undeveloped reserves can be subject to an even greater possibility of revision. At year-end, 23 percent of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, a significant percentage are related to our project in Wyoming and our Western Oklahoma, Cana-Woodford shale play. Our reserve engineers review and revise our reserve estimates regularly, as new information becomes available. As further discussed in *Recently Issued Accounting Standards*, the SEC and FASB amended oil and gas reporting requirements effective December 31, 2009. The impact to Cimarex was minimal, apart from the change to a new standard using 12 month average pricing rather than prices in effect at the end of a period.

We use the units-of-production method to amortize the cost of our oil and gas properties. Changes in reserve quantities and commodity prices will cause corresponding changes in depletion expense in periods subsequent to these changes, or in some cases, a full cost ceiling limitation charge in the period of the revision.

Transportation Costs

Amounts paid for transportation are classified as an operating expense and are not netted against gas sales.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Derivatives

Our derivative contracts are recorded on the balance sheet at fair value. 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 (loss) 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 are recognized in gas revenues in the period the contracts are settled. Cash settlements of our derivative contracts are included in cash flows from operating activities in our statements of cash flows.

Our derivative contracts outstanding during 2007 and 2008 were designated as cash flow hedges. Accordingly, the realized gains or losses upon settlement of the 2007 and 2008 contracts were reflected in gas revenue as an adjustment to the realized sales price. In 2007 and 2008, unrealized gains and losses were recorded in accumulated other comprehensive income. At December 31, 2008, there were no remaining contracts outstanding.

During 2009, we entered into additional derivative contracts which cover a portion of our anticipated production through December 2010. We did not choose to apply hedge accounting treatment to any of the contracts we have entered into in the current year. As such, settlements on these contracts will not impact our realized commodity prices during the periods they cover. Instead, any settlements on these contracts will be shown as a component of operating costs and expenses as a realized (gain) loss on derivative instruments. See Note 4 for additional information regarding our derivative instruments.

Income Taxes

Deferred income taxes are computed using the liability method. Deferred income taxes are provided on all temporary differences between the financial basis and the tax basis of assets and liabilities. Valuation allowances are established to reduce deferred tax assets to an amount that more likely than not will be realized.

We account for uncertainty in our income tax provisions in accordance with rules promulgated by the FASB. At December 31, 2009 we have no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax provisions.

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.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

In January 2009, the Tulsa County District Court issued a judgment in the H.B. Krug, et al versus Helmerich & Payne, Inc. ("H&P") case. This lawsuit was originally filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. Damages of $6.9 million, plus $119.5 million for disgorgement of H&P's estimated potential compounded profit since 1989 resulting from the noted damages, were awarded to plaintiff royalty owners for a total of $126.4 million. This amount was subsequently adjusted by the court to a total of $119.6 million. Pursuant to the 2002 spin-off transaction to shareholders of H&P by which Cimarex became a publicly-traded entity, Cimarex assumed the assets and liabilities of H&P's exploration and production business. In 2008 we had accrued litigation expense of $119.6 million for this lawsuit. During 2009, we have accrued an additional $9.4 million. We have appealed the District Court's judgments.

In the normal course of business, we have other various litigation related matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. For the year 2009, we had approximately $10.0 million of such expenses. Though some of the related claims may be significant, the resolution of them we believe, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations.

Asset Retirement Obligations

We recognize 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.

Stock Options

Effective January 1, 2005, we adopted FASB guidance on share based payments on a modified prospective basis. We recognize in the income statement the grant-date fair value of stock options and other equity-based compensation to employees.

Earnings per Share

In 2008, the FASB issued new guidance which holds that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are "participating securities" (as defined as securities that may participate in undistributed earnings with common stock, whether that participation is conditioned upon the occurrence of a specified event or not, regardless of the form of participation), and therefore should be included in computing earnings per share using the two-class earnings allocation method. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. The guidance became effective for financial statements issued in fiscal years beginning after December 15, 2008, and for interim periods within those years. The requirements are to be applied by recasting previously reported earnings per share data. Under this guidance, our unvested share based payment awards, consisting of restricted

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

stock and restricted stock units, qualify as participating securities. We adopted this guidance in the first quarter of 2009.

Comprehensive Income (Loss)

Comprehensive income is a term used to refer to net income plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under generally accepted accounting principles are reported as separate components of shareholders' equity instead of net income.The components of other comprehensive income (loss) are as follows (in 000's):

	Net Unrealized Gain on Derivative Instruments(1)	Net Unrealized Gain (or Loss) On Short-Term Investments and Other(1)	Accumulated Other Comprehensive Income (Loss)
Balance at January 1, 2007	$ 30,954	$ 127	$ 31,081
2007 activity	(23,302)	(153)	(23,455)
Balance at December 31, 2007	$ 7,652	$ (26)	$ 7,626
2008 activity	(7,652)	(929)	(8,581)
Balance at December 31, 2008	$	$ (955)	$ (955)
2009 activity		936	936
Balance at December 31, 2009	$	$ (19)	$ (19)

(1) Net of tax

The table below sets forth the changes in the Company's unrealized gains on derivative instruments included as a component of comprehensive income (loss) for the years ended December 31, 2009 and 2008 (in 000's):

	2009	2008
Unrealized derivative gain in comprehensive income at January 1,	$	$ 12,088
Change in fair value		(851)
Reclassification of net gains to income		(11,272)
Net ineffectiveness		35
Related income tax effect		
Unrealized derivative gain in comprehensive income (loss) at December 31,	$	$

Segment Information

Cimarex has one reportable segment (exploration and production).

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Recently Issued Accounting Standards

In June 2009, the FASB approved the FASB Accounting Standards Codification (ASC), which after its launch on July 1, 2009 became the single source of authoritative, nongovernmental U.S. Generally Accepted Accounting Principles (GAAP). The Codification reorganizes all previous U.S. GAAP pronouncements into roughly 90 accounting topics and displays all topics using a consistent structure. All existing standards that were used to create the Codification are now superseded, replacing the previous references to specific Statements of Financial Accounting Standards with numbers used in the Codification's structural organization.

In December 2008, the SEC issued revised reporting requirements for oil and gas reserves that a company holds. Included in the new rule entitled *Modernization of Oil and Gas Reporting Requirements,* are the following changes: 1) permitting use of additional technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; 2) enabling companies to disclose their probable and possible reserves to investors, in addition to their proved reserves; 3) allowing previously excluded resources, such as oil sands, to be classified as oil and gas reserves rather than mining reserves; 4) requiring companies to report the independence and qualifications of a preparer or auditor; 5) requiring the filing of reports for companies that rely on a third party to prepare reserve estimates or conduct a reserve audit; and 6) requiring companies to report oil and gas reserves using an average price based upon the prior 12-month period, rather than period-end prices. The new requirements are effective for registration statements filed on or after January 1, 2010, and for annual reports on Form 10K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted.

In January 2010, the FASB issued an Accounting Standards Update (ASU) 2010-03, *Extractive Industries Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosure.* This ASU amends the FASB accounting standards to align the reserve calculation and disclosure requirements with the requirements in the new SEC Rule, *Modernization of Oil and Gas Reporting Requirements*. The ASU is effective for reporting periods ending on or after December 31, 2009.

Subsequent Events

The accompanying financial disclosures include an evaluation of subsequent events through February 26, 2010.

4. DERIVATIVE INSTRUMENTS/HEDGING

We periodically enter into derivative instruments to mitigate a portion of our potential exposure to a decline in commodity prices and the corresponding negative impact on cash flow available for reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes.

On January 1, 2009, we adopted provisions set forth by the FASB which requires qualitative and quantitative disclosures about objectives and strategies for using derivatives, how such derivatives are accounted for and how the derivative instruments affect an entity's financial position, results of operations, and cash flows.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

At December 31, 2009, we had the following outstanding contracts relative to our future production. We have elected not to account for these derivatives as cash flow hedges.

Natural Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Weighted Average Price Swap	Fair Value (000's)
Jan 10 - Dec 10	Collar	100,000 MMBtu	PEPL	$ 5.00	$ 6.62		$ 2,228
Jan 10 - Dec 10	Swap	40,000 MMBtu	PEPL			$ 5.18	$ (5,289)
Jan 10 - Dec 10	Collar	20,000 MMBtu	HSC	$ 5.00	$ 6.85		$ (10)

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000's)
Jan 10 - Dec 10	Collar	10,000 Bbls	WTI	$ 60.03	$ 92.07	$ (10,164)
Jan 10 - Dec 10	Put/Floor	1,000 Bbls	WTI	$ 60.00		$ 570

(1) PEPL refers to Panhandle Eastern Pipe Line Company price and HSC refers to Houston Ship Channel price, both as quoted in Platt's Inside FERC on the first business day of each month. WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

The combined gas and oil contracts that expire in 2010 represents approximately 40% of our equivalent oil and gas production for 2010. We do not anticipate entering into further contracts related to our 2010 production.

Under a collar agreement, we receive the difference between the published index price and a floor price if the index price is below the floor. We pay the difference between the 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 floor and ceiling prices. Under a floor contract, if the settlement price for a settlement period is below the floor price, we receive the difference between the settlement price and the floor price. We are not required to make any payments in connection with the settlement of a floor contract. For a swap contract, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price. We are required to make a payment to the counterparty if the settlement price for the settlement period is greater than the swap price.

Our derivative contracts are carried at their fair value on our balance sheet. We estimate the fair value using internal risk adjusted discounted cash flow calculations. Cash flows are based on the stated contract prices and current and projected published forward commodity price curves, adjusted for volatility. Due to the volatility of commodity prices, the estimated fair values of our derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. The following table presents the estimated fair

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

values of our derivative assets and liabilities as of December 31, 2009. At December 31, 2008, we had no derivative instruments outstanding.

	Balance Sheet Location		Asset	Liability
			(In thousands)	
Derivatives not designated as hedging instruments:				
Natural gas contracts	Current assets	Derivative instruments	$ 1,238	$
Natural gas contracts	Current liabilities	Derivative instruments	$	$ 4,308
Oil contracts	Current liabilities	Derivative instruments	$	$ 9,594

Because we have elected not to account for our current derivative contracts as cash flow hedges, we recognize all realized and unrealized changes in fair value in earnings. The derivative contracts that were outstanding in 2008 were treated as cash flow hedges. Accordingly, the realized gains or losses upon settlement of the 2008 contracts were reflected in gas revenue as an adjustment to the realized sales price. In 2008, unrealized gains and losses were recorded in accumulated other comprehensive income (which is included in shareholders' equity). Cash settlements of our derivative contracts are included in cash flows from operating activities in our statements of cash flows.

The following table summarizes the realized and unrealized gains and losses from cash settlements and changes in fair value of our derivative contracts as presented in our accompanying financial statements.

	Years Ended December 31,		
	2009	2008	2007
Derivatives not designated as hedging instruments:			
Cash settlements gains:			
Natural gas contracts	$ 1,394	$	$
Oil contracts			
Total cash settlements gains	1,394		
Unrealized losses on fair value change:			
Natural gas contracts	(3,070)		
Oil contracts	(11,383)		
Total net unrealized losses on fair value change	(14,453)		
Loss on derivative instruments, net	$ (13,059)	$	$
Derivatives designated as cash flow hedges:			
Natural gas contracts gains:			
Cash receipts included in gas sales	$	$ 11,272	$ 27,829
Unrealized gains on fair value change included in other comprehensive income (loss)	$	$	$ 7,652

We are exposed to financial risks associated with these contracts from non-performance by our counterparties. Counterparty risk is also a component of our estimated fair value calculations. We have

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

mitigated our exposure to any single counterparty by contracting with eight financial institutions, each of which has a high credit rating and is a member of our bank credit facility. Our member banks have a secured interest in our oil and gas properties, and therefore do not require us to post collateral for our hedge liability positions.

5. FAIR VALUE MEASUREMENTS

The FASB has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 inputs are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for an asset or liability. The following tables provide fair value measurement information for certain assets and liabilities as of December 31, 2009 and 2008.

	Carrying Amount	Fair Value
	(In thousands)	
December 31, 2009:		
Financial Assets (Liabilities):		
Derivative instruments	$ 1,238	$ 1,238
Derivative instruments	$ (13,902)	$ (13,902)
7.125% Notes due 2017	$ (350,000)	$ (354,375)
Bank debt	$ (25,000)	$ (25,000)
Floating rate convertible notes due 2023	$ (17,793)	$ (36,036)

	Carrying Amount	Fair Value
	(In thousands)	
December 31, 2008:		
Financial Assets (Liabilities):		
Short-term investments	$ 2,502	$ 2,502
7.125% Notes due 2017	$ (350,000)	$ (267,750)
Bank debt	$ (220,000)	$ (220,000)
Floating rate convertible notes due 2023	$ (17,630)	$ (19,450)

Assessing the significance of a particular input to the fair value measurement requires judgment, considering factors specific to the asset or liability. The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Short-term Investments (Level 2)

In the fourth quarter of 2007, we invested $16 million in an asset-backed securities fund, which was liquidated in the third quarter of 2009. The investments were classified as available-for-sale, and at the end of each period, changes in the fair value of the investments are recorded in other comprehensive income (loss). The fair values of these investments were based on a net asset valuation provided by the fund manager. During 2009, we liquidated the remaining investments for $3.3 million, with a realized gain of $280 thousand, which was included in earnings for the period. During 2008, we liquidated $10.4 million of the investments, with a realized loss of $395 thousand and an impairment charge of $801 thousand, both of

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FAIR VALUE MEASUREMENTS (Continued)

which were included in earnings for the period. We also reflected an unrealized loss of $664 thousand in other comprehensive income (loss) as of December 31, 2008.

Bank Debt and Notes

Debt

The fair value of our bank debt is estimated to approximate the carrying amount because we recently entered into a new revolving credit facility. Interest on the facility is a floating rate based on either (a) a London Interbank Offered Rate ("LIBOR") plus 2 to 3 percent, based on borrowing base usage, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50 percent, or (iii) adjusted LIBOR, in each case, plus an additional 1.125 to 2.125 percent, based on borrowing base usage. Each of the floating rate interest options resets periodically.

Notes

The fair values for our 7.125% fixed rate notes were based on their last traded value before year end.

There is not an observable market for our convertible notes. At December 31, 2009, the requirements for the closing price of our common stock exceeded the conversion rate of $28.59 attributable to the conversion feature; therefore, the fair value of the convertible notes at December 31, 2009 included value attributable to both the face amount of the notes and the conversion feature. The conversion rate of $28.59 attributable to the conversion feature at December 31, 2008 exceeded requirements for the closing price of our common stock; therefore, no value was attributed to the conversion feature at December 31, 2008. The fair value of the notes was estimated to approximate the face value of the notes because the notes bear interest at LIBOR, and reset quarterly.

Derivative Instruments

The fair value of our derivative instruments at December 31, 2009 was estimated using internal discounted cash flow calculations. Cash flows are based on the stated contract prices and current and published forward commodity price curves, adjusted for volatility. The cash flows are risk adjusted relative to non-performance for both our counterparties and our liability positions. At December 31, 2008, we had no derivative instruments outstanding.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities of these assets and liabilities. At December 31, 2009, the allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $5.9 million, $1.0 million, and zero, respectively. At December 31, 2008, the allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $5.1 million, $0.7 million, and zero, respectively.

Most of our accounts receivable balances are uncollateralized and result from transactions with other companies in the oil and gas industry. Concentration of customers may impact our overall credit risk because our customers may be similarly affected by changes in economic or other conditions within the industry.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. ASSET RETIREMENT OBLIGATIONS

We recognize 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. 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. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement capitalized cost. Capitalized costs are depleted as a component of the full cost pool.

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the years ended December 31, 2009 and 2008 (in thousands):

	2009	2008
Asset retirement obligation at January 1,	$ 139,948	$ 113,054
Liabilities incurred	3,730	6,095
Liability settlements and disposals	(15,598)	(8,882)
Accretion expense	7,819	6,663
Revisions of estimated liabilities	13,411	23,018
Asset retirement obligation at December 31,	149,310	139,948
Less current obligation	19,525	14,610
Long-term asset retirement obligation	$ 129,785	$ 125,338

During 2009 we recognized a revision of $13 million to our asset retirement obligation primarily from an increase in abandonment cost estimates for our Gulf of Mexico properties. During 2008 a revision of $23 million to our asset retirement obligation resulted primarily from an overall increase in abandonment cost estimates and changes in the productive lives of our wells.

7. LONG TERM DEBT

Debt at December 31, 2009 and 2008 consisted of the following (in thousands):

	2009	2008
Bank debt	$ 25,000	$ 220,000
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023 (face value $19,450)	17,793	17,630
Total long-term debt	$ 392,793	$ 587,630

Bank Debt

In April 2009, we entered into a new three-year senior secured revolving credit facility ("credit facility"). The new credit facility increased bank commitments from $500 million to $800 million, with a borrowing base of $1 billion. The credit facility is provided by a syndicate of banks led by JP Morgan Chase Bank, N.A., matures on April 14, 2012 and is secured by mortgages on certain of our oil and gas properties and the stock of certain wholly-owned operating subsidiaries.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG TERM DEBT (Continued)

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations.

The credit facility contains covenants and restrictive provisions which may limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility requires us to maintain a current ratio (defined to include undrawn borrowings) greater than 1 to 1 and a leverage ratio not to exceed 3.5 to 1. As of December 31, 2009, we were in compliance with all of the financial and non-financial covenants.

At Cimarex's option, borrowings under the credit facility may bear interest at either (a) a London Interbank Offered Rate ("LIBOR") plus 2 to 3 percent, based on borrowing base usage, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50 percent, or (iii) adjusted LIBOR, in each case, plus an additional 1.125 to 2.125 percent, based on borrowing base usage.

At December 31, 2009, there was $25 million of borrowings outstanding under the credit facility at a weighted average interest rate of approximately 2.2%. We also had letters of credit outstanding of $16.7 million leaving an unused borrowing availability of $758.3 million.

7.125% Notes due 2017

In May, 2007, we issued $350 million of 7.125% senior unsecured notes that mature May 1, 2017 at par. Interest on the notes is payable May 1 and November 1 of each year. The notes are governed by an indenture containing covenants that could limit our ability to incur additional indebtedness; pay dividends or repurchase our common stock; make investments and other restricted payments; incur liens; enter into sale/leaseback transactions; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets.

The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 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
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

At any time prior to May 1, 2010, we may redeem up to 35% of the original principal amount of the notes with the proceeds of certain equity offerings of our shares of common stock at a redemption price of 107.125% of the principal amount of the notes, together with accrued and unpaid interest, if any, to the date of redemption. At any time prior to May 1, 2012, we may also redeem all, but not part, of the notes at a price of 100% of the principal amount of the notes plus accrued and unpaid interest plus a "make-whole" premium.

If a specified change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest to the date of the purchase.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG TERM DEBT (Continued)

Floating rate convertible notes due 2023

The floating rate convertible senior notes mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On December 31, 2009, the interest rate approximated 0.3%.

In December 2008, holders of $105.5 million of the original $125 million issuance amount elected to submit their notes for repurchase. We repurchased the $105.5 million in notes with borrowings under our credit facility. Holders of the remaining $19.5 million of notes have optional repurchase dates as of December 15, 2013, and 2018.

In addition to the repurchase rights, 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 110% of the conversion price of $28.59 per share for a defined period of time. As of December 31, 2008, the notes were not convertible. However, based on the price of our common stock, the notes became convertible effective October 1, 2009 and continue to be convertible through the first quarter of 2010.

At our option, we may offer to redeem the notes at any time at par. In addition, if a change of control occurs, subject to certain conditions, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes.

In May 2008, the FASB issued new guidance that changed the accounting for the components of convertible debt that can be settled wholly or partly in cash upon conversion. The new requirements are required to be applied to both new instruments and retrospectively to previously issued convertible instruments. The debt and equity components of the instruments are accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as of the issuance date, with the remaining proceeds allocated to the equity component and recorded as additional paid-in capital. The debt component is recorded at a discount and is subsequently accreted to its par value, thereby reflecting an overall market rate of interest in the income statement. The effective interest rate for the years ended December 31, 2009, 2008 and 2007 was 2.0%, 4.4% and 7.1%, respectively.

We adopted this guidance on January 1, 2009. The following table reflects a comparison of certain financial statement line items affected by the retrospective application of this guidance.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. LONG TERM DEBT (Continued)

Summary of the Retrospective Application of Changes (amounts in thousands):

	For the Year Ended December 31, 2008		For the Year Ended December 31, 2007	
	After Adoption	As Previously Reported	After Adoption	As Previously Reported
Changes to the Consolidated Statements of Operations:				
Interest expense	$ 33,079	$ 32,064	$ 39,105	$ 37,966
Amortization of fair value of debt	$	$ (709)	$ (1,146)	$ (1,908)
(Gain) loss on early extinguishment of debt	$ 10,058	$ (9,569)	$ (5,099)	$ (5,099)
Income before income tax expense (benefit)	$ (1,451,649)	$ (1,430,298)	$ 542,724	$ 544,625
Income tax expense (benefit)	$ (536,404)	$ (528,613)	$ 197,462	$ 198,156
Net income (loss)	$ (915,245)	$ (901,685)	$ 345,262	$ 346,469

	At December 31, 2008	
	After Adoption	As Previously Reported
Changes to the Consolidated Balance Sheets:		
Long-term debt	$ 587,630	$ 591,223
Deferred income taxes	$ 500,945	$ 499,634
Paid-in capital	$ 1,874,834	$ 1,855,825
Retained earnings	$ 510,271	$ 526,998

8. INCOME TAXES

Federal income tax expense (benefit) for the years ended December 31, 2009, 2008, and 2007 differ from the amounts that would be provided by applying the U.S. Federal income tax rate, due to the effect of state income taxes, and the Domestic Production Activities allowance. The components of the provision for income taxes are as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Current taxes:			
Federal	$ (11,335)	$ 65,323	$ 26,993
State	(443)	866	3,656
	(11,778)	66,189	30,649
Deferred taxes:			
Federal	(158,264)	(576,699)	161,477
State	(6,496)	(25,894)	5,336
	(164,760)	(602,593)	166,813
	$ (176,538)	$ (536,404)	$ 197,462

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. INCOME TAXES (Continued)

Reconciliations of the income tax (benefit) expense calculated at the federal statutory rate of 35% to the total income tax (beneft) expense are as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Provision at statutory rate	$ (170,969)	$ (508,044)	$ 189,974
Effect of state taxes	(6,863)	(26,453)	8,992
Domestic Production Activities allowance	663	(2,208)	(1,723)
Other	631	301	219
Income tax (benefit) expense	$ (176,538)	$ (536,404)	$ 197,462

The components of Cimarex's net deferred tax liabilities are as follows (in thousands):

	December 31,	
	2009	2008
Long-term:		
Assets:		
Other	$ 42,980	$ 37,411
	42,980	37,411
Liabilities:		
Property, plant and equipment	(391,877)	(538,356)
Net, long-term deferred tax liability	(348,897)	(500,945)
Current:		
Assets:		
Derivative instruments	5,274	
Other	10,563	2,435
	15,837	2,435
Net deferred tax liabilities	$ (333,060)	$ (498,510)

We have recorded deferred tax assets of $58.8 million the realization of which is dependent on generating sufficient taxable income in the future.

We account for uncertainty in our income tax provisions in accordance with rules promulgated by the FASB. At December 31, 2008 and 2009 we had no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2005 - 2008 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities which remain open for tax years 2005 - 2008 for examination.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. CAPITAL STOCK

A summary of the Company's Common Stock activity follows:

	Number of Shares (in thousands)		
	Issued	**Treasury**	**Outstanding**
December 31, 2006	83,962	(1,079)	82,883
Restricted shares issued under compensation plans, net of cancellations	511		511
Option exercises, net of cancellations	262		262
Treasury shares purchased		(1,114)	(1,114)
Treasury shares cancelled	(1,114)	1,114	
December 31, 2007	83,621	(1,079)	82,542
Restricted shares issued under compensation plans, net of cancellations	441		441
Option exercises, net of cancellations	276		276
Treasury shares cancelled	(194)	194	
December 31, 2008	84,144	(885)	83,259
Restricted shares issued under compensation plans, net of cancellations	166		166
Option exercises, net of cancellations	117		117
Treasury shares cancelled	(885)	885	
December 31, 2009	83,542		83,542

Stock-based Compensation

Our 2002 Stock Incentive Plan was approved by stockholders in May 2003 and is effective until October 1, 2012. The plan provides for grants of stock options, restricted stock and restricted stock units to non-employee directors, officers and other eligible employees. A total of 12.7 million shares of common stock may be issued under the Plan.

Restricted Stock and Units

During 2009 we issued a total of 381,090 restricted shares to non-employee directors, officers, and other employees. Included in that amount are 228,000 shares issued to certain executives that are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group's stock price performance. After three years of continued service, an executive will be entitled to vest in 50% to 100% of the award. The material terms of performance goals applicable to these awards were approved by stockholders in May 2006. The other shares granted in 2009 have service-based vesting schedules of three to five years.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. CAPITAL STOCK (Continued)

The following table presents restricted stock activity during the last three years:

	Years Ended December 31,		
	2009	**2008**	**2007**
Outstanding beginning of period	1,672,245	1,289,695	792,779
Vested	(166,725)	(28,470)	(13,693)
Granted	381,090	464,620	572,009
Canceled	(159,360)	(53,600)	(61,400)
Outstanding end of period	1,727,250	1,672,245	1,289,695

The following table presents restricted unit activity during the last three years:

	Years Ended December 31,		
	2009	**2008**	**2007**
Outstanding beginning of period	655,205	701,915	696,641
Converted to Stock	(5,362)	(45,500)	
Granted		3,790	5,274
Canceled		(5,000)	
Outstanding end of period	649,843	655,205	701,915
Vested included in outstanding	620,559	596,247	559,839

Vesting of restricted stock and units granted in years before 2006 is exclusively related to continued service of the grantee for one to five years. In certain cases, a three year required holding period following vesting also applies. A restricted unit represents a right to an unrestricted share of common stock upon completion of defined vesting and holding periods. The restricted stock and stock unit agreements provide that grantees are entitled to receive dividends on unvested shares.

Compensation expense for service-based vesting restricted shares or units is based upon amortization of the grant-date market value of the award. The fair value of the market condition-based restricted stock is based on the grant-date market value of the award utilizing a Monte Carlo simulation model to estimate the percentage of awards that will vest at the end of the three-year period. Compensation expense related to the restricted stock and unit awards is recognized ratably over the applicable vesting period. We recorded compensation costs related to the restricted stock and units as follows (in thousands):

	Years Ended December 31,		
	2009	**2008**	**2007**
Compensation costs:			
Recorded as expense	$ 8,048	$ 9,363	$ 8,875
Capitalized to oil and gas properties	$ 5,356	$ 6,128	$ 3,863

Unamortized compensation costs related to unvested restricted shares and units at December 31, 2009, 2008, and 2007 was $27.1 million, $33.6 million, and $31.7 million, respectively.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. CAPITAL STOCK (Continued)

Stock Options

Options granted under our plan expire ten years from the grant date and have service-based vesting schedules of three to five years. The plan provides that all grants have an exercise price of the average of the high and low prices of our common stock as reported by the New York Stock Exchange on the date of grant.

There were 228,175 stock options granted to employees during 2009. Information about outstanding stock options is summarized below:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (000)
Outstanding as of January 1, 2009	1,532,016	$ 29.95		
Exercised	(134,082)	16.51		
Granted	228,175	27.74		
Canceled	(1,499)	56.74		
Forfeited	(50,636)	55.59		
Outstanding as of December 31, 2009	1,573,974	$ 29.93	5.3 Years	$ 38,488
Exercisable as of December 31, 2009	1,029,629	$ 23.02	3.5 Years	$ 31,887

There were 134,082, 414,449 and 454,263 stock options exercised during 2009, 2008 and 2007, respectively. Cash received from option exercises during the years ended December 31, 2009, 2008, and 2007 was $2.2 million, $6.4 million, and $5.9 million, respectively, and the related tax benefits realized from option exercises totaled $1.2 million, $6.7 million, and $4.0 million, respectively, and were recorded to paid-in capital. The total intrinsic value of stock options exercised during 2009, 2008 and 2007 was $3.3 million, $18.9 million and $11.0 million, respectively.

The weighted-average grant-date fair value of stock options granted during the years ended December 31, 2009, 2008 and 2007 was $11.11, $19.44 and $15.62, respectively. We estimate the fair value of options as of the date of grant using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the probability of option exercise, expected years until exercise and potential forfeitures. The risk-free interest rate we use is the five-year U.S. Treasury bond in effect at the date of the grant.

The following summarizes the assumptions used to determine the fair market value of options issued during the last three years:

	Years Ended December 31,		
	2009	2008	2007
Expected years until exercise	5.5	5.5	7.5
Expected stock volatility	43.4%	32.4%	32.3%
Dividend yield	0.9%	0.6%	0.6%
Risk-free interest rate	2.7%	3.5%	3.3%

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. CAPITAL STOCK (Continued)

The following summary reflects the status of non-vested stock options granted as of December 31, 2009 and changes during the year:

	Shares	Weighted Average Grant Date Fair Value
Non-vested as of January 1, 2009	529,620	$ 18.96
Vested	(162,814)	18.94
Granted	228,175	11.11
Forfeited	(50,636)	19.10
Non-vested as of December 31, 2009	544,345	$ 15.66

We recognize compensation cost ratably over the vesting period. During 2009, 2008 and 2007, compensation costs (including capitalized amounts) were $3.4 million, $1.7 million and $1.9 million, respectively. Historical amounts may not be representative of future amounts as additional options may be granted.

As of December 31, 2009 there was $6.9 million of unrecognized compensation cost related to non-vested stock options granted under our stock incentive plan. We expect to recognize that cost pro rata over a weighted-average period of 2.0 years. The weighted average exercise price of the non-vested stock options is $42.99.

The total grant-date fair value of options that vested during 2009, 2008 and 2007 was $3.1 million, $0.4 million and $2.0 million, respectively.

Stockholder Rights Plan

We have a stockholder rights plan. The plan is designed to improve the ability of our board to protect the interests of our stockholders in the event of an unsolicited takeover attempt. For every outstanding share of Cimarex common stock, there exists one purchase right (the Right). Each Right represents a right to purchase one one-hundredth of a share of Series A Junior Participating Preferred Stock, at a purchase price of $60.00 per share, subject to adjustment in certain cases, to prevent dilution. The Rights will become exercisable only in the event a person or group acquires beneficial ownership of 15% or more of our common stock, or a person or group commences a tender offer or exchange offer that, if successfully consummated, would result in such person or group beneficially owning 15% or more of our common stock. In general, in either of these events, each holder of a right, other than the person or group initiating the acquisition or tender offer, will have the right to receive Cimarex common stock with a value equal to two times the exercise price of the right.

We generally will be entitled to redeem the Rights under certain circumstances at $0.01 per Right at any time before the close of business on the tenth business day after there has been a public announcement of the acquisition of beneficial ownership by any person or group of 15% or more of our common stock. The Rights may not be exercised until our Board's right to redeem the stock has expired. Unless redeemed earlier, the Rights expire on February 23, 2012.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. CAPITAL STOCK (Continued)

Dividends and Stock Repurchases

In December 2005, the Board of Directors declared our first quarterly cash dividend of $0.04 per share. A dividend has been authorized every quarter since then. In December 2007, the dividend was increased to $0.06 per share. Future dividend payments will depend on the Company's level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

In December 2005, the Board of Directors authorized the repurchase of up to four million shares of our common stock. The authorization is currently set to expire on December 31, 2011. Through December 31, 2007, we had repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. Purchases may be made in both the open market and through negotiated transactions, and purchases may be increased, decreased or discontinued at any time without prior notice. There were no shares repurchased in the fourth quarter of 2009, or since the quarter ended September 30, 2007.

Issuer Purchases of Equity Securities for the Quarter Ended December 31, 2009

	Total Number of Shares purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of shares that may yet be Purchased Under the Plans or Programs
October, 2009	None	NA	None	2,635,700
November, 2009	None	NA	None	2,635,700
December, 2009	None	NA	None	2,635,700

10. EARNINGS (LOSS) PER SHARE

In 2008, the FASB issued new guidance which holds that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are "participating securities" (as defined as securities that may participate in undistributed earnings with common stock, whether that participation is conditioned upon the occurrence of a specified event or not, regardless of the form of participation), and therefore should be included in computing earnings per share using the two-class earnings allocation method. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. The guidance became effective for financial statements issued in fiscal years beginning after December 15, 2008, and for interim periods within those years. The requirements are to be applied by recasting previously reported earnings per share data. Under this guidance, our unvested share based payment awards, consisting of restricted stock and restricted stock units, qualify as participating securities. We adopted this guidance in the first quarter of 2009.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. EARNINGS (LOSS) PER SHARE (Continued)

The calculations of basic and diluted net earnings (loss) per common share under the two-class method are presented below (in thousands, except per share data):

	Years Ended December 31,		
	2009	**2008**	**2007**
Net income (loss)	$ (311,943)	$ (915,245)	$ 345,262
Less distributed earnings (dividends declared during the period)	(20,282)	(20,108)	(14,991)
Undistributed earnings (loss) for the period	$ (332,225)	$ (935,353)	$ 330,271
Allocation of undistributed earnings (loss):			
Basic allocation to unrestricted common stockholders	$ (332,225)	$ (935,353)	$ 322,369
Basic allocation to participating securities	$ (2)	$ (2)	$ 7,902
Diluted allocation to unrestricted common stockholders	$ (332,225)	$ (935,353)	$ 322,553
Diluted allocation to participating securities	$ (2)	$ (2)	$ 7,718
Basic Shares Outstanding			
Unrestricted outstanding common shares	81,815	81,587	81,252
Add participating securities:			
Restricted stock outstanding	1,727	1,672	1,290
Restricted stock units outstanding	650	655	702
Total participating securities	2,377	2,327	1,992
Total basic shares outstanding	84,192	83,914	83,244
Fully Diluted Shares			
Unrestricted outstanding common shares	81,815	81,587	81,252
Incremental shares from assumed exercise of stock options	(1)	(1)	611
Incremental shares from assumed conversion of the convertible senior notes	(1)	(1)	1,375
Fully diluted common stock	81,815	81,587	83,238
Participating securities	2,377(2)	2,327(2)	1,992
Total fully diluted shares	84,192	83,914	85,230
Basic earnings (loss) per share			
Unrestricted common stockholders:			
Distributed earnings	$ 0.24	$ 0.24	$ 0.18
Undistributed earnings (loss)	(4.06)	(11.46)	3.97
	$ (3.82)	$ (11.22)	$ 4.15
Participating securities:			
Distributed earnings	$ 0.24	$ 0.24	0.18

Undistributed earnings (loss)						3.97
	$	0.24	$	0.24	$	4.15
Fully diluted earnings (loss) per share						
Unrestricted common stockholders:						
Distributed earnings	$	0.24	$	0.24	$	0.18
Undistributed earnings (loss)		(4.06)		(11.46)		3.87
	$	(3.82)	$	(11.22)	$	4.05
Participating securities:						
Distributed earnings	$	0.24	$	0.24	$	0.18
Undistributed earnings (loss)						3.87
	$	0.24	$	0.24	$	4.05

(1) No potential common shares or securities are included in the diluted share computation when a loss from continuing operations exists.

(2) Participating securities are included in distributed earnings and not in undistributed earnings when a loss from continuing operations exists.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. EARNINGS (LOSS) PER SHARE (Continued)

All stock options and restricted units and shares and the convertible notes were considered potentially dilutive securities for each of the periods presented except for those determined to be anti-dilutive as follows:

	2009	2008	2007
Stock options	1,573,974	1,532,016	90,900
Restricted stock	1,727,250	1,672,245	
Restricted stock units	649,843	655,205	
Convertible notes	311,200		
	4,262,267	3,859,466	90,900

11. EMPLOYEE BENEFIT PLANS

We maintain and sponsor a contributory 401(k) plan for our employees. Costs related to the plan were $5.1 million, $5.2 million, and $5.2 million in the years ended December 31, 2009, 2008, and 2007, respectively.

12. RELATED PARTY TRANSACTIONS

Helmerich & Payne, Inc. provides contract drilling services to Cimarex. Drilling costs of approximately $17.5 million, $40.2 million, and $21.5 million were incurred by Cimarex related to such services for the years ended December 31, 2009, 2008, and 2007, respectively. At December 31, 2009, we have minimum expenditure commitments of $16.2 million to secure the use of Helmerich & Payne, Inc.'s drilling rigs. At December 31, 2008, we had minimum expenditure commitments of $26.2 million. We had no such commitments at December 31, 2007. Hans Helmerich, a director of Cimarex, is President and Chief Executive Officer of Helmerich & Payne, Inc. Certain subsidiaries of Newpark Resources, Inc. have provided various drilling services to Cimarex. Costs of such services were $10.8 million, $24.3 million, and $15.6 million for the years ended December 31, 2009, 2008, and 2007, respectively. In 2009, Cimarex sold excess casing to a subsidiary of Newpark Resources, Inc. for $108 thousand. Jerry Box, a director of Cimarex, is a non-executive director and Chairman of the Board of Newpark Resources, Inc.

13. MAJOR CUSTOMERS

During 2009, sales to one purchaser represented approximately 14% of our revenues. No individual purchasers represented more than 10% of our revenues for the years ended December 31, 2008 and 2007.

14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION (in thousands)

	For the Years Ended December 31,		
	2009	2008	2007
Cash paid during the period for:			
Interest (net of amounts capitalized)	$ 10,668	$ 8,902	$ 19,006
Interest capitalized	$ 23,408	$ 22,108	$ 19,680
Income taxes	$ 2,270	$ 128,861	$ 2,408
Cash received for income taxes	$ 94,617	$ 4,251	$ 46,518

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. COMMITMENTS AND CONTINGENCIES

Shown below are the five year debt maturities and five year lease commitments as of December 31, 2009:

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
	(In thousands)				
Long term debt (face value)	$ 394,450	$	$ 25,000	$	$ 369,450
Operating leases	$ 20,994	$ 5,092	$ 9,588	$ 6,032	$ 282

Litigation

In January 2009, the Tulsa County District Court issued a judgment in the H.B. Krug, et al versus Helmerich & Payne, Inc. ("H&P") case. This lawsuit was originally filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage issues and other related matters. Damages of $6.9 million, plus $119.5 million for disgorgement of H&P's estimated potential compounded profit since 1989 resulting from the noted damages, were awarded to plaintiff royalty owners for a total of $126.4 million. This amount was subsequently adjusted by the court to a total of $119.6 million. Pursuant to the 2002 spin-off transaction to shareholders of H&P by which Cimarex became a publicly-traded entity, Cimarex assumed the assets and liabilities of H&P's exploration and production business. In 2008 we had accrued litigation expense of $119.6 million for this lawsuit. During 2009, we have accrued an additional $9.4 million. We have appealed the District Court's judgments.

In the normal course of business, we have other various litigation related matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. For the year 2009, we had approximately $10.0 million of such expenses. Though some of the related claims may be significant, the resolution of them we believe, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations.

Other

We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At December 31, 2009, we had commitments of $151.2 million relating to construction of the gas processing plant of which $96.2 million is subject to a construction contract. The total cost of the project will approximate $345 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

We have drilling commitments of approximately $72.9 million consisting of obligations to complete drilling wells in progress at December 31, 2009. We also have minimum expenditure commitments of $50.7 million to secure the use of drilling rigs.

At December 31, 2009, we have a purchase commitment of $11.1 million for construction of an aircraft. The total cost of the aircraft is $12.3 million with an option to trade in our existing aircraft. The completion of the aircraft is expected to be no later than October 30, 2010.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. COMMITMENTS AND CONTINGENCIES (Continued)

At December 31, 2009, we had firm sales contracts to deliver approximately 1.9 Bcf of natural gas over the next three months. If this gas is not delivered, our financial commitment would be approximately $11.1 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we do not anticipate that a financial commitment will be due.

In connection with a gas gathering and processing agreement, we have commitments to deliver 55.7 Bcf of gas over the next four years. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $41.6 million, some of which will be reimbursed by working interest owners who are selling with us under our marketing agreement.

We have 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 $4.7 million, some of which will be reimbursed by working interest owners who are selling with us under our marketing agreements.

We have non-cancelable operating leases for office and parking space in Denver, Tulsa, Dallas, and for small district and field offices. Rental expense for the operating leases totaled $6 million, $6.4 million, and $5.9 million for the years ended December 31, 2009, 2008, and 2007, respectively.

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

16. PROPERTY SALES AND ACQUISITIONS

Various interests in oil and gas properties were sold during 2009 and 2008 for $109.4 million and $38.1 million, respectively. These were recorded as a reduction to oil and gas properties. There were no significant acquisitions during 2009. Subsequent to year end we acquired additional interests in our Western Oklahoma Cana-Woodford shale play for approximately $23 million.

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES

Oil and Gas Operations The following tables contain direct revenue and cost information relating to our oil and gas exploration and production activities for the periods indicated. We have no long-term supply or purchase agreements with governments or authorities in which we act as producer. Income tax expense (benefit) related to our oil and gas operations are computed using the effective tax rate for the period (in thousands):

	Years Ended December 31, 2009	2008	2007
Oil and gas revenues from production	$ 962,443	$ 1,880,891	$ 1,364,622
Less operating costs and income taxes:			
Impairment of oil and gas properties	791,137	2,242,921	
Depletion	243,471	527,813	444,546
Asset retirement obligation	12,313	8,796	8,937
Production	178,215	218,736	201,512
Transportation	33,758	38,107	26,361
Taxes other than income	75,634	130,490	93,630
Income tax expense (benefit)	(134,472)	(475,295)	214,510
	1,200,056	2,691,568	989,496
Results of operations from oil and gas producing activities	$ (237,613)	$ (810,677)	$ 375,126
Amortization rate per Mcfe	$ 1.44	$ 2.97	$ 2.70

Costs Incurred The following table sets forth the capitalized costs incurred in our oil and gas production, exploration, and development activities (in thousands):

	Years Ended December 31, 2009	2008	2007
Costs incurred during the year:			
Acquisition of properties			
Proved	$ 13,530	$ 6,618	$ 17,334
Unproved	24,804	310,666	102,572
Exploration	59,350	268,052	236,866
Development	430,357	1,035,442	666,662
Oil and gas expenditures	528,041	1,620,778	1,023,434
Property sales	(109,408)	(38,093)	(176,659)
	418,633	1,582,685	846,775
Asset retirement obligation, net	12,850	24,822	(18,207)
	$ 431,483	$ 1,607,507	$ 828,568

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

Aggregate Capitalized Costs The table below reflects the aggregate capitalized costs relating to our oil and gas producing activities at December 31, 2009 (in thousands):

Proved properties	$ 7,549,861
Unproved properties and properties under development, not being amortized	399,724
	7,949,585
Less-accumulated depreciation, depletion and amortization	(5,764,669)
Net oil and gas properties	$ 2,184,916

Costs Not Being Amortized The following table summarizes oil and gas property costs not being amortized at December 31, 2009, by year that the costs were incurred (in thousands):

2009	$ 109,958
2008	271,551
2007	16,677
2006 and prior	1,538
	$ 399,724

Costs not being amortized include the costs of wells in progress and certain unevaluated properties. On a quarterly basis, such costs are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Abandonments of unproved properties are accounted for as an adjustment to capitalized costs related to proved oil and gas properties, with no losses recognized.

Oil and Gas Reserve Information Effective December 31, 2009, the SEC and the FASB adopted amendments to required oil and gas reporting disclosures. The amendments were designed to modernize disclosure requirements and to align them with current practices and changes in technology. The revised rules require reserve calculations to be based on the unweighted average first-day-of-the-month prices for the prior twelve months. In prior years, proved reserves were based on prices in effect at period end. The current rules permit the use of additional technologies to determine proved reserves, if those technologies have been demonstrated empirically to lead to reliable conclusions about recoverable volumes. Companies may also disclose their probable and possible reserves to investors. We have chosen to not make such disclosures. The effect of our adoption of the new rules was minimal, apart from the change to using the 12-month average pricing.

Proved oil and gas reserve quantities are based on estimates prepared by Cimarex in accordance with guidelines established by the Securities and Exchange Commission (SEC). Reserve definitions comply with definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. All reserve estimates of Cimarex are maintained by the Company's internal Corporate Reservoir Engineering group, which is comprised of reservoir engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of our company. The technical employee primarily responsible for overseeing the oil and gas reserve estimation process is our company's Vice President Corporate Engineering. This individual graduated from the Colorado School of Mines

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

with a Bachelor of Science degree in Engineering and has more than fifteen years of practical experience in oil and gas reserve evaluation. This individual has been directly involved in the annual SEC reserve reporting process of Cimarex since 2002 and serving in the current role for the past five years.

DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, reviewed greater than eighty percent of the total future net revenue discounted at ten percent attributable to the total interests owned by Cimarex as of December 31, 2009. The technical individual primarily responsible for overseeing the reserves review is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over thirty-five years of experience in oil and gas reservoir studies and evaluations.

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and the timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. For year-end 2009, the commodity prices were determined using an average price based upon the prior 12 months. For the years ended 2008 and 2007, commodity prices were based upon prices in effect at year end.

	December 31, 2009		December 31, 2008		December 31, 2007	
	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)
Total proved reserves						
Beginning of year	1,067,333	45,202	1,122,694	58,250	1,090,362	59,797
Revisions of previous estimates	6,718	11,201	(57,989)	(16,465)	50,027	1,251
Extensions, discoveries & improved recovery	229,625	13,770	143,570	11,884	162,136	13,361
Purchases of reserves	2,106	300	2,483	55	10,571	99
Production	(117,968)	(8,498)	(127,444)	(8,395)	(119,937)	(7,446)
Sales of properties	(1,229)	(3,958)	(15,981)	(127)	(70,465)	(8,812)
End of year	1,186,585	58,017	1,067,333	45,202	1,122,694	58,250
Proved developed reserves	865,720	53,889	834,517	44,520	848,001	51,497
Proved undeveloped reserves	320,865	4,128	232,816	682	274,693	6,753

Proved undeveloped ("PUD") reserves at December 31, 2008 totaled 237 Bcfe, approximately 89% of which was associated with a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. During 2009 we invested a total of $20.1 million in this project and our cumulative investment in this project is $70.9 million. We presently expect that we will initiate gas sales from this project in 2011. Two Bcfe of PUD reserves were converted to proved developed reserves during 2009. PUD reserves increased 111 Bcfe

Table of Contents

during 2009 through new additions and revisions to previous estimates. Most of these additions occurred in our Western Oklahoma, Cana-Woodford shale play. Proved undeveloped reserves at December 31, 2009 totaled 346 Bcfe. We have no PUD reserves that have remained undeveloped for five years or more after initial disclosure.

Standardized Measure of Future Net Cash Flows The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" (Standardized Measure) is calculated in accordance with guidance provided by the FASB. The Standardized Measure does not purport, nor should it be interpreted, to present the fair value of a company's proved oil and gas reserves. Fair value would require, among other things, consideration of expected future economic and operating conditions, a discount factor more representative of the time value of money, and risks inherent in reserve estimates.

Under the Standardized Measure, future cash inflows are based upon the forecasted future production of year-end proved reserves. Future cash inflows are then reduced by estimated future production and development costs to determine net pre-tax cash flow. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash flow over our tax basis in the associated oil and gas properties. Tax credits and permanent differences are also considered in the future income tax calculation. Future net cash flow after income taxes is discounted using a ten percent annual discount rate to arrive at the Standardized Measure.

The following summary sets forth our Standardized Measure (in thousands):

	December 31,		
	2009	2008	2007
Cash inflows	$ 7,521,219	$ 7,314,200	$ 12,674,941
Production costs	(2,773,338)	(2,681,510)	(3,673,259)
Development costs	(354,340)	(229,546)	(540,555)
Income tax expense	(1,205,984)	(1,173,658)	(2,689,836)
Net cash flow	3,187,557	3,229,486	5,771,291
10% annual discount rate	(1,519,602)	(1,505,233)	(2,873,660)
Standardized measure of discounted future net cash flow	$ 1,667,955	$ 1,724,253	$ 2,897,631

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

The following are the principal sources of change in the Standardized Measure (in thousands):

	December 31,		
	2009	**2008**	**2007**
Standardized Measure, beginning of period	$ 1,724,253	$ 2,897,631	$ 2,200,889
Sales, net of production costs	(674,836)	(1,493,558)	(1,043,121)
Net change in sales prices, net of production costs	(427,313)	(1,683,984)	976,912
Extensions, discoveries and improved recovery, net of future production and development costs	730,969	742,889	858,632
Net change in future development costs	60,419	334,565	136,413
Revision of quantity estimates	106,521	(243,985)	168,877
Accretion of discount	232,790	424,312	308,660
Change in income taxes	(14,327)	741,834	(459,777)
Purchases of reserves in place	10,624	6,956	31,278
Sales of properties	(34,038)	(29,986)	(123,268)
Change in production rates and other	(47,107)	27,579	(157,864)
Standardized Measure, end of period	$ 1,667,955	$ 1,724,253	$ 2,897,631

Impact of Pricing The 2009 estimates of cash flows and reserve quantities shown above are based upon the unweighted average first-day-of-the-month prices for 2009. The prior years' estimates are based on year-end oil and gas prices. In all years where future gas sales are covered by contracts at specified prices, the contract prices are used. Fluctuations in prices are due to supply and demand and are beyond our control.

The following average prices were used in determining the Standardized Measure as of:

	December 31,		
	2009	**2008**	**2007**
Price per Mcf	$ 3.56	$ 5.33	$ 6.51
Price per Bbl	$ 57.58	$ 36.34	$ 93.66

At December 31, 2009, the impact of adopting the new rules requiring the use of a twelve month average price, rather than prices in effect at year end, was significant to our reserve volumes and more so to our reserve values. At year end the reference prices for gas and oil were $5.79 per MMBtu and $79.36 per barrel, respectively, whereas the twelve month average reference prices were $3.87 per MMBtu and $61.18 per barrel. Adjusted for regional differentials, the average prices used were $3.56 per Mcf and $57.58 per barrel. Had prices in effect at year end been used, we believe our December 31, 2009 total equivalent proved reserve volumes would be approximately five to six percent greater than those calculated using the average price. We estimate that the Standardized Measure at year end would be approximately 60 percent greater if prices in effect at year end had been used.

Under SEC rules, companies that follow full cost accounting methods are required to make quarterly "ceiling test" calculations. Under this test, capitalized costs of oil and gas properties, net of accumulated DD&A and deferred income taxes, may not exceed the present value of estimated future net revenues

Table of Contents

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. UNAUDITED SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

from proved reserves, discounted at ten percent, plus the lower of cost or fair market value of unproved properties, as adjusted for related tax effects. We calculate the projected income tax effect using the "year-by-year" method for purposes of the supplemental oil and gas disclosures and use the "short-cut" method for the ceiling test calculation. Application of these rules during periods of relatively low oil and gas prices, even if of short-term duration, may result in write-downs.

18. UNAUDITED SUPPLEMENTAL QUARTERLY FINANCIAL DATA

2009	**First**	**Second**	**Third**	**Fourth**
	(In thousands, except for per share data)			
Revenues	$ 209,179	$ 222,685	$ 249,134	$ 328,796
Expenses, net	703,279	183,878	210,429	224,151
Net income (loss)	$ (494,100)	$ 38,807	$ 38,705	$ 104,645
Earnings (loss) per share to common stockholders:				
Basic				
Distributed	$ 0.06	$ 0.06	$ 0.06	$ 0.06
Undistributed	(6.11)	0.40	0.40	1.18
	$ (6.05)	$ 0.46	$ 0.46	$ 1.24
Diluted				
Distributed	$ 0.06	$ 0.06	$ 0.06	$ 0.06
Undistributed	(6.11)	0.40	0.40	1.17
	$ (6.05)	$ 0.46	$ 0.46	$ 1.23

2008	**First**	**Second**	**Third**	**Fourth**
	(In thousands, except for per share data)			
Revenues	$ 477,210	$ 617,043	$ 577,258	$ 298,836
Expenses, net	327,672	388,030	809,681	1,360,209
Net income (loss)	$ 149,538	$ 229,013	$ (232,423)	$ (1,061,373)
Earnings (loss) per share to common stockholders:				
Basic				
Distributed	$ 0.06	$ 0.06	$ 0.06	$ 0.06
Undistributed	1.73	2.67	(2.91)	(13.07)
	$ 1.79	$ 2.73	$ (2.85)	$ (13.01)

Diluted								
Distributed	$	0.06	$	0.06	$	0.06	$	0.06
Undistributed		1.67		2.59		(2.91)		(13.07)
	$	1.73	$	2.65	$	(2.85)	$	(13.01)

The sum of the individual quarterly net income per common share amounts may not agree with year-to-date net income per common share because each period's computation is based on the weighted average number of shares outstanding during that period.

Table of Contents

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Cimarex's management, with the participation of the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), have evaluated the effectiveness of Cimarex's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e)) as of December 31, 2009 and concluded that the disclosure controls and procedures are effective in providing reasonable assurance that the information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow such persons to make timely decisions regarding required disclosures.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Cimarex Energy Co. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The Company's internal control over financial reporting is a process designed under the supervision of the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles.

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

As of December 31, 2009, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria established in "Internal Control Integrated Framework", issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, the Company maintained effective internal control over financial reporting as of December 31, 2009.

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Cimarex Energy Co:

We have audited Cimarex Energy Co. and subsidiaries (the Company's) internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Cimarex Energy's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated February 26, 2010 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Denver, Colorado
February 26, 2010

Table of Contents

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF CIMAREX

Information concerning the directors of Cimarex is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2010 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2010. Information concerning the executive officers of Cimarex is set forth under Item 4A in Part I of this report.

ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2010 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2010.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2010 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2010.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2010 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2010.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 19, 2010 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than April 30, 2010.

Table of Contents

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated by reference to a prior SEC filing as indicated.

2.1 Agreement and Plan of Merger, dated as of February 23, 2002, among Helmerich & Payne, Inc., Cimarex Energy Co., Mountain Acquisition Co. and Key Production Company, Inc. (filed as Exhibit 2.1 to the Registrant's Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

2.2 Agreement and Plan of Merger, dated as of January 25, 2005, among Cimarex Energy Co., Cimarex Nevada Acquisition Co. and Magnum Hunter Resources, Inc. (attached as Annex A to the joint proxy statement/prospectus which forms a part of the Registration Statement on Form S-4 dated February 25, 2005 (Registration No. 333-123019) and incorporated herein by reference).

2.3 Amendment No. 1 to Agreement and Plan of Merger, dated as of February 18, 2005, among Cimarex Energy Co., Cimarex Nevada Acquisition Sub and Magnum Hunter Resources, Inc. (attached as Annex A to the joint proxy statement/prospectus which forms a part of the Registration Statement on Form S-4 dated February 25, 2005 (Registration No. 333-123019) and incorporated herein by reference).

2.4 Amendment No. 2 to Agreement and Plan of Merger, dated as of April 20, 2005, among Cimarex Energy Co., Cimarex Nevada Acquisition Sub and Magnum Hunter Resources, Inc. (attached as Annex A to the joint proxy statement/prospectus which forms a part of this registration statement and incorporated herein by reference).

3.1 Amended and Restated Certificate of Incorporation of Cimarex Energy Co. (filed as Exhibit 3.1 to Registrant's Form 8-K (file no. 001-31446) dated June 7, 2005 and incorporated herein by reference).

3.2 Amended and Restated By-laws of Cimarex Energy Co. (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K dated September 20, 2007 and incorporated herein by reference).

4.1 Specimen Certificate of Cimarex Energy Co. common stock (filed as Exhibit 4.1 to Amendment No. 1 to Registration Statement on Form S-4 dated July 2, 2002 (Registration No. 333-87948) and incorporated herein by reference).

4.2 Rights Agreement, dated as of February 23, 2002, between Cimarex Energy Co. and UMB Bank, N.A. (filed as Exhibit 4.2 to the Registration Statement on Form S-4 (Registration No. 333-87948) and incorporated herein by reference).

Table of Contents

4.3 Indenture dated December 15, 2003 between Magnum Hunter Resources, Inc., the subsidiary guarantors named therein and Deutsche Bank Trust Company Americas, as Trustee (incorporated by reference to Magnum Hunter's Form 10-K for the year ended December 31, 2003).

4.4 Form of Floating rate Convertible Senior Notes due 2023 (included in Exhibit 4.5).

4.5 First Supplemental Indenture dated as of June 13, 2005, among Cimarex Energy Co., the Subsidiary Guarantors party thereto and Deutsche Bank Trust Company Americas, (filed as Exhibit 4.1 to Registrant's Form 8-K (file no. 001-31446) dated June 17, 2005 and incorporated herein by reference).

4.6 Second Supplemental Indenture dated as of June 7, 2005, among Cimarex Energy Co., Magnum Hunter Resources, Inc., the Subsidiary Guarantors party thereto and Deutsche Bank Trust Company Americas (filed as Exhibit 4.1 to Registrant's Form 8-K (file no. 001-31446) dated June 7, 2005 and incorporated herein by reference).

4.7 Third Supplemental Indenture dated as of June 13, 2005, among Cimarex Energy Co., the Subsidiary Guarantors party thereto and Deutsche Bank Trust Company Americas (filed as Exhibit 4.1 to Registrant's Form 8-K (file no. 001-31446) dated June 17, 2005, and incorporated herein by reference).

4.8 Registration Rights Agreement dated as of December 17, 2003, among Magnum Hunter Resources, Inc., the subsidiary guarantors named therein and Deutsche Bank Securities Inc. and Banc of America Securities LLC, as representatives of the initial purchasers (filed as Exhibit 4.10 to Registrant's Form S-3 Registration Statement (file no. 333-125235) dated May 25, 2005 and incorporated herein by reference).

4.9 Joinder to Registration Rights Agreement dated as of June 13, 2005, among Cimarex Texas LLC, Cimarex Texas L.P., Cimarex California Pipeline LLC, Cimarex Energy Services, Inc., Key Production Company, Inc., Key Texas LLC, Key Production Texas L.P., Brock Gas Systems & Equipment, Inc., Columbus Energy Corp., Columbus Texas, Inc., Columbus Energy L.P. and Columbus Gas Services, Inc. (filed as Exhibit 4.3 to Registrant's Form 8-K (file no. 001-31446) dated June 17, 2005 and incorporated herein by reference).

4.10 Senior Indenture dated as of May 1, 2007, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee, filed on May 2, 2007 as Exhibit 4.1 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

4.11 Form of Senior Notes due 2017 included in Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on May 2, 2007 and incorporated herein by reference.

10.1 Credit Agreement dated as of April 14, 2009, among Cimarex, the Lenders, the Administrative Agent, the Co-Syndication Agents, the Co-Documentation Agents and the Lead Arranger filed on April 20, 2009 as Exhibit 10.l to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

10.2 Distribution Agreement, dated as of February 23, 2002, by and between Helmerich & Payne, Inc. and Cimarex Energy Co. (filed as Exhibit 10.1 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

Table of Contents

10.3 Employee Benefits Agreement, dated as of February 23, 2002, by and between Helmerich & Payne, Inc. and Cimarex Energy Co. (filed as Exhibit 10.3 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.4 First Amendment to Employee Benefits Agreement, dated August 2, 2002, by and among Helmerich & Payne, Inc., Cimarex Energy Co. and Key Production Company, Inc. (filed as Exhibit 10.3.1 to Amendment No. 2 to the Registration Statement on Form S-4 dated August 2, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.5 Employment Agreement dated September 1, 1992 between Key Production Company, Inc. and F.H. Merelli (filed as Exhibit 10.5 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.6 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and F. H. Merelli (filed as Exhibit 10.7 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.7 Employment Agreement, dated September 7, 1999, by and between Paul Korus and Key Production Company, Inc. (filed as Exhibit 10.6 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.8 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Paul Korus (filed as Exhibit 10.9 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.9 Employment Agreement, dated October 25, 1993, by and between Thomas E. Jorden and Key Production Company, Inc. (filed as Exhibit 10.7 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.10 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Thomas E. Jorden (filed as Exhibit 10.11 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.11 Employment Agreement, dated February 2, 1994, by and between Stephen P. Bell and Key Production Company, Inc. (filed as Exhibit 10.8 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.12 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Stephen P. Bell (filed as Exhibit 10.13 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.13 Employment Agreement, dated March 11, 1994, by and between Joseph R. Albi and Key Production Company, Inc. (filed as Exhibit 10.9 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.14 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Joseph R. Albi (filed as Exhibit 10.15 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.15 Amended and Restated 2002 Stock Incentive Plan of Cimarex Energy Co. effective January 1, 2009 (filed as Exhibit 10.16 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.16 Form of Performance Award Agreement dated January 4, 2006 (filed as Exhibit 10.1 to Registration's Form 8-K dated January 4, 2006 (File no. 001-31446) and incorporated herein by reference).

Table of Contents

10.17 Deferred Compensation Plan for Nonemployee Directors adopted May 19, 2004, as amended and restated effective January 1, 2009 (filed as Exhibit 10.18 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.18 Cimarex Energy Co. Supplemental Savings Plan (amended and restated, effective January 1, 2009) (filed as Exhibit 10.19 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.19 Cimarex Energy Co. Change in Control Severance Plan dated effective April 1, 2005. amended and restated effective January 1, 2009 (filed as Exhibit 10.20 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.20 Indemnification Agreement effective December 5, 2008 with Jerry Box (filed as Exhibit 10.21 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.21 Indemnification Agreement effective December 5, 2008 with Hans Helmerich (filed as Exhibit 10.22 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.22 Indemnification Agreement effective December 5, 2008 with David A. Hentschel (filed as Exhibit 10.23 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.23 Indemnification Agreement effective December 5, 2008 with Paul D. Holleman (filed as Exhibit 10.24 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.24 Indemnification Agreement effective December 5, 2008 with F. H. Merelli (filed as Exhibit 10.25 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.25 Indemnification Agreement effective December 5, 2008 with Monroe W. Robertson (filed as Exhibit 10.26 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.26 Indemnification Agreement effective December 5, 2008 with Michael J. Sullivan (filed as Exhibit 10.27 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.27 Indemnification Agreement effective December 5, 2008 with L. Paul Teague (filed as Exhibit 10.28 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.28 Indemnification Agreement effective February 26, 2009 with Gary R. Abbott (filed as Exhibit 10.29 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.29 Indemnification Agreement effective February 26, 2009 with Joseph R. Albi (filed as Exhibit 10.30 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.30 Indemnification Agreement effective December 5, 2008 with Stephen P. Bell (filed as Exhibit 10.31 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

Table of Contents

10.31	Indemnification Agreement effective December 5, 2008 with Richard S. Dinkins (filed as Exhibit 10.32 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.32	Indemnification Agreement effective December 5, 2008 with Thomas A. Jorden (filed as Exhibit 10.33 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.33	Indemnification Agreement effective December 5, 2008 with Paul Korus (filed as Exhibit 10.34 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
10.34	Indemnification Agreement effective December 5, 2008 with James H. Shonsey (filed as Exhibit 10.35 to the Annual Report on Form 10-K filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).
14.1	Code of Ethics for Chief Executive Officer and Senior Financial Officers (filed as Exhibit 14.1 to the Annual Report on Form 10-K for the year ended December 31, 2003, file no. 001-31446, and incorporated herein by reference).
21.1	Subsidiaries of the Registrant.*
23.1	Consent of KPMG LLP.*
23.2	Consent of DeGolyer and MacNaughton*
24.1	Power of Attorney of directors of the Registrant.*
31.1	Certification of F.H. Merelli, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32.1	Certification of F.H. Merelli, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
32.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*
99.1	Letter dated January 29, 2010 from DeGolyer and MacNaughton, independent petroleum engineering consulting firm, reporting the results of its audit of Cimarex reserves as of December 31, 2009 of certain selected properties.*
101	The following materials from the Cimarex Energy Co. Annual Report on Form 10-K for the year ended December 31, 2009, formatted in XBRL (eXtensible Business Reporting Language) includes (i) the Consolidated Statements of Operations, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Stockholder's Equity and Comprehensive Income (Loss), and (v) Notes to the Consolidated Financial Statements, tagged as blocks of text.

Users of this data are advised pursuant to Rule 401 of Regulation S-T that the financial information contained in the XBRL-Related Documents is unaudited. Furthermore, users of this data are advised in accordance with Rule 406T of Regulation S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

Table of Contents

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: February 26, 2010

CIMAREX ENERGY CO.
By: /s/ F.H. MERELLI

F.H. Merelli
Chairman, President and Chief Executive Officer

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

Signature	Title	Date
/s/ F.H. MERELLI F.H. Merelli	Director, Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 26, 2010
/s/ PAUL KORUS Paul Korus	Vice President, Chief Financial Officer, and Treasurer (Principal Financial Officer)	February 26, 2010
/s/ JAMES H. SHONSEY James H. Shonsey	Vice President, Chief Accounting Officer and Controller (Principal Accounting Officer)	February 26, 2010
* Jerry Box	Director	February 26, 2010
* Hans Helmerich	Director	February 26, 2010
* David A. Hentschel	Director	February 26, 2010
* Paul D. Holleman	Director	February 26, 2010

Table of Contents

Signature	Title	Date
* Harold R. Logan, Jr.	Director	February 26, 2010
* Monroe W. Robertson	Director	February 26, 2010
* Michael J. Sullivan	Director	February 26, 2010
* L. Paul Teague	Director	February 26, 2010
*By: /s/ F.H. MERELLI F. H. Merelli *Attorney-in-Fact*		February 26, 2010