CIMAREX ENERGY CO
Form 10-K/A
August 16, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D C 20549

Form 10-K/A

Amendment No. 1

(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, 2010

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 ($0.01 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, 2010 was approximately $5,888,486,826.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 18, 2011 was 85,520,628.

Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2011 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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EXPLANATORY NOTE

We are filing this Amendment No. 1 (this "Amendment") to our annual report on Form 10-K for the year ended December 31, 2010 to expand the disclosures related to the areas listed below. Our consolidated financial results have not changed from those presented in our original Form 10-K. For ease of reference, we are filing the annual report in its entirety with the following changes:

In Item 7 and in our footnotes we expanded our disclosure describing the full cost ceiling test. This disclosure is found in Item 7 under Critical Accounting Polices and Estimates *Full Cost Accounting*, in the Summary of Significant Accounting Polices footnote under our discussion of oil and gas properties and in the Unaudited Supplemental Oil and Gas Disclosures footnote.

In the Summary of Significant Accounting Policies footnote under *Revenue Recognition* and in the Unaudited Supplemental Oil and Gas Disclosures footnote we expanded our NGL discussion to explain in more detail how we determine whether to record and separately disclose NGL volumes.

In our Commitments and Contingencies footnote under *Litigation*, we expanded our discussion about litigation accruals made in 2009 and 2010.

In the Unaudited Supplemental Oil and Gas Disclosures footnote we expanded our discussion of the effect in 2009 of adopting new rules related to reporting proved oil and gas reserves. Further, we expanded the narrative disclosure regarding the 2010 increase in proved reserves through extensions and discoveries to include the technologies employed in the estimation of our proved reserves.

Except as identified above, no other items or disclosures in our Form 10-K have been amended. This Amendment does not reflect events occurring after February 25, 2011, the original filing date of our Form 10-K.

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DESCRIPTION

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GLOSSARY

Bbl/d Barrels (of oil or natural gas liquids) per day

Bbls Barrels (of oil or natural gas liquids)

Bcf Billion cubic feet

Bcfe Billion cubic feet equivalent

Btu British thermal unit

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 Cimarex's working interest percentage

Net Production Gross production multiplied by Cimarex's net revenue interest

NGL Natural gas liquids

Tcf Trillion cubic feet

Tcfe Trillion cubic feet equivalent

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

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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;
- marketing of oil and natural gas;
- legislation and regulatory changes;
- access to capital markets.

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

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forward-looking statements to reflect events or circumstances after the date of filing this Form 10-K with the Securities and Exchange Commission, except as required by law.

ITEM 1. BUSINESS

General

Cimarex Energy Co., a Delaware corporation, 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 2010 totaled 1.9 Tcfe, consisting of 1.3 Tcf of gas and 105 million barrels of oil and natural gas liquids. Of total proved reserves, 67% are gas and 77% are classified as proved developed. Our 2010 production averaged 595.9 MMcfe per day, comprised of 363.9 MMcf of gas per day and 38,674 barrels of oil and natural gas liquids per day. We operate the wells that account for 79% of our total proved reserves and approximately 85% 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.

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 available in print upon a written or telephonic 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 & 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. Since 2005, we have principally focused on exploration and development drilling and have funded these investments with cash flow provided by operating activities.

2010 Summary

During 2010 we accomplished the following highlights:

- Realized record net income of $575 million, or $6.70 (diluted) per share
- Grew production 29% to an all-time high of 596 MMcfe per day
- Increased proved reserves 23% to 1.9 Tcfe
- Added 560 Bcfe of proved reserves from extensions, discoveries and revisions replacing 258% of production
- Reduced debt $43 million, exiting the year with a debt to total capitalization ratio of 12%

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

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properties and profitably reinvesting that cash flow in exploration and development drilling. During 2010, our cash flow from operations totaled approximately $1.19 billion. Our total 2010 capital investment was $1.04 billion, including $999 million on exploration and development.

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 2010 we had $350 million of long-term debt and our debt to total capitalization ratio was 12%.

2011 Outlook

Our 2011 exploration and development capital investment is presently expected to be in the range of $1.2-$1.4 billion, principally funded from cash flow. We project our 2011 production to grow 3-8% over 2010. We anticipate approximately 55% of the capital investment to be directed toward the Permian Basin, 38% to the Mid-Continent and 7% to the Gulf Coast and other.

As has been our historical practice, we regularly review our capital expenditures throughout the year and will adjust our investments based on changes in commodity prices, service costs and drilling success. We have the flexibility to adjust our capital expenditures based upon market conditions. For 2011, the majority of our oil and gas production is not hedged. We have approximately 5-6% of our gas and 40-45% of our oil production hedged. For a complete discussion of our hedging activities, a listing of open contracts as of December 31, 2010 and the estimated fair value of these contracts as of that date, see Note 4, "Derivative Instruments/Hedging," to our consolidated financial statements.

Business Segments

Cimarex has one reportable segment (exploration and production).

Exploration and Development Overview

Our exploration and development (E&D) 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.

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We drilled and completed 219 gross (129 net) wells during 2010, investing $999 million on E&D. Of total expenditures, 45% were invested in projects located in the Mid-Continent area; 42% in the Permian Basin; and 12% in the Gulf Coast.

A summary of our 2010 exploration and development activity by region is as follows.

	Exploration and Development Capital (in millions)	Gross Wells Drilled	Net Wells Drilled	Completion Rate	12/31/10 Proved Reserves (Bcfe)
Mid-Continent	$ 451	114	44	97%	1,028.9
Permian Basin	419	92	74	96%	561.2
Gulf Coast	116	11	10	82%	83.1
Wyoming/Other	13	2	1	50%	210.8
	$ 999	219	129	95%	1,884.0

Mid-Continent

Our Mid-Continent region encompasses operations in Oklahoma, southwest Kansas and the Texas Panhandle. We drilled 114 gross (44 net) Mid-Continent wells during 2010, completing 97% as producers. The bulk of this drilling activity was in the Anadarko Basin of western Oklahoma. Full-year 2010 investment in this area was $451 million, or 45% of total E&D capital.

In the Anadarko Basin of western Oklahoma, our largest investment is in the Cana-Woodford shale 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 2010, we drilled and completed 86 gross (32.8 net) horizontal Cana-Woodford wells. At year-end there were 26 gross (10.2 net) wells waiting on completion. We have approximately 100,000 net acres in the play.

Since the Cana play began in late 2007, Cimarex has participated in a total of 189 gross (70.8 net) wells. Of total wells, 143 gross (55 net) were on production and the remainder were either in the process of being drilled or awaiting completion at year-end 2010. On average gross estimated well-head recovery exceeds 6.7 Bcfe per well. Our acreage positions have multiple years of drilling opportunity.

In the Texas Panhandle, we drilled 14 gross (7.4 net) successful Granite Wash and Morrow wells. Our land position in the Texas Panhandle is primarily in Roberts and Hemphill counties.

Permian Basin

Our Permian Basin operations cover west Texas and southeast New Mexico. Drilling principally occurred in the Delaware Basin portion of New Mexico, mainly targeting the Bone Spring, Abo and Paddock formations. In total, we drilled 92 gross (74 net) wells in this area during 2010 completing 88 gross (70 net) as producers. Full-year 2010 investment in this area totaled $419 million, or 42% of total E&D capital. Our 2010 drilling focused on horizontal oil plays.

We are also evaluating multiple shale intervals in the Delaware Basin, including the Wolfcamp, Avalon and Cisco/Canyon. In southern Eddy County New Mexico and Culberson County Texas, we drilled seven horizontal Wolfcamp shale wells in 2010. Thirty-day average initial production on these wells averaged 6.3 MMcfe/d, comprised of 3.1 MMcf/d of gas, 188 barrels per day of oil and 340 barrels per day of NGLs. The wells had an average lateral length of 3,800'.

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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. Compared to our other core areas, we often experience larger potential reserves per well, greater drilling depths and lower success rates in the Gulf Coast. Full-year 2010 investment in the Gulf Coast area was $116 million, or 12% of total E&D capital. During 2010 we drilled 11 gross (10.2 net) Gulf Coast wells, realizing an 82% success rate. The majority of the activity occurred near Beaumont in Jefferson County, Texas, where ten gross (9.2 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 2010 capital investment activity was less than $1 million.

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 2010 we invested a total of $39.6 million in this project and our cumulative investment in this project is $110.5 million. We presently expect that we will initiate gas sales from this project in 2011. Our share of the total investment, including planned expansion, will approximate $200 million.

Production, Pricing and Cost Information

The following table sets forth certain information regarding the company's production volumes, the average commodity prices received and production cost per Mcfe. In 2010, the proved reserves of our Cana-Woodford shale play, located in Watonga-Chickasha field, were 26.7% of our total proved reserves. No other field had reserves in excess of 15% of our total proved reserves.

	Total Company Years Ending December 31,			Total Watonga-Chickasha Field (Cana-Woodford) Year Ending December 31,
	2010	**2009**	**2008**	**2010**
Production Volumes:				
Gas (MMcf)	132,813	117,968	127,444	18,669
Oil (MBbls)	9,844	8,278	8,241	358
NGL (MBbls)	4,272	220	154	1,480
Equivalent (MMcfe)	217,509	168,956	177,814	29,697
Net Average Daily Volumes:				
Gas (MMcf)	363.9	323.2	348.2	51.1
Oil (MBbls)	27.0	22.7	22.5	1.0
NGL (MBbls)	11.7	0.6	0.4	4.1
Equivalent (MMcfe)	595.9	462.9	485.8	81.4
Average Sales Price:				
Gas ($/Mcf)	$ 4.92	$ 4.12	$ 8.43	$ 4.34
Oil ($/Bbl)	$ 76.76	$ 56.63	$ 96.76	$ 76.76
NGL ($/Bbl)	$ 34.91	$ 37.11	$ 57.10	$ 33.84
Production Cost ($/Mcfe)	$ 0.89	$ 1.05	$ 1.23	$ 0.10

Total equivalent 2010 production grew 29% averaging 595.9 MMcfe per day as compared to 462.9 MMcfe per day in 2009. Gas production in 2010 increased 13% to 363.9 MMcf per day and oil and NGL production grew 66% to 38,674 barrels per day. A portion of the NGL increase results from 2010 changes in contractual terms clarifying where title transfer occurs which determines how volumes are recorded.

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The following table summarizes Cimarex's daily production by region for 2010 and 2009.

	2010 Average Daily Production				2009 Average Daily Production			
	Gas (MMcf/d)	Oil (MBbl/d)	NGL (MBbl/d)	Total (MMcfe/d)	Gas (MMcf/d)	Oil (MBbl/d)	NGL (MBbl/d)	Total (MMcfe/d)
Mid-Continent	194.1	4.7	5.5	255.4	187.8	4.8	0.3	218.5
Permian Basin	71.5	14.0	1.7	165.4	78.9	13.6	0.2	161.4
Gulf Coast	97.3	8.3	4.5	174.1	54.2	4.2	0.1	80.2
Other	1.0			1.0	2.3	0.1		2.8
	363.9	27.0	11.7	595.9	323.2	22.7	0.6	462.9

Our largest producing area is the Mid-Continent region. During 2010 our Mid-Continent production averaged 255.4 MMcfe per day, or 43% of our total 2010 production. Drilling activity in our western Oklahoma Cana-Woodford shale play and in the Texas Panhandle Granite Wash resulted in Mid-Continent production increasing 17% in 2010.

The Permian Basin contributed 165.4 MMcfe per day in 2010, which was 28% of our total production. Permian drilling increased throughout 2010 as a result of continuing improvement in oil prices and return on investment. Our operated rig count went from five in the first-quarter 2010 to 12 by the fourth quarter. Most of the activity was horizontal oil drilling in the Bone Spring, Abo and Paddock formations. Oil production grew 3% in 2010 over 2009 and 18% from first-quarter 2010 to fourth-quarter.

Gulf Coast production averaged 174.1 MMcfe per day during 2010, or 29% of total production. Full-year 2010 Gulf Coast volumes increased over 110% as compared to 2009 as a result of exploration success in Jefferson County Texas, near Beaumont. Gulf Coast volumes can fluctuate significantly depending on timing of exploration success relative to natural production declines.

Acquisitions and Divestitures

During 2010, we sold oil and gas properties, mostly in Mississippi, for a total of $28.2 million. Associated proved reserves were 8.7 Bcfe. Through several transactions in 2010 totaling $38 million we acquired additional interests in our Cana-Woodford shale play.

We sold various oil and gas properties in 2009 for a total of $109.4 million, to which we attributed 25 Bcfe of proved reserves. The largest transaction was $79 million for an interest in a West Texas secondary oil field. There were no significant acquisitions during 2009.

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.

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 two largest customers accounted for approximately 22% and 15%, respectively, of 2010 revenues. Because over 95% of our gas production is from wells in Texas, Oklahoma, New Mexico, Kansas 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.

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Employees

We employed 775 people on December 31, 2010. 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 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.

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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.

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, gas, and NGL 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 prices. The prices we receive for our 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, governmental regulations and taxes, and the price and technological advancement of alternative fuels.

Historically, oil and gas prices have fluctuated widely. In 2010 we sold our gas at an average price of $4.92 per Mcf, which was 19% higher than our 2009 average sales price of $4.12 per Mcf. Our average 2010 oil price of $76.76 per barrel was 36% higher than the price we received in 2009 of $56.63 per barrel. The higher realized prices in 2010 increased sales from 2009 to 2010 by $295.0 million. In contrast, our 2009 average gas price was 51% lower than our 2008 average sales price of $8.43 per Mcf, and our 2009 average oil price was 41% lower than our 2008 average oil sales price of $96.76. The lower realized prices in 2009 compared to 2008 decreased sales from 2008 to 2009 by $845.0 million.

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 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 may also be impacted.

If prices decrease, we may be required to take 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 impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken. For example, low prices contributed to reductions in the carrying value of our oil and gas properties of $2.2 billion and $791 million in 2008 and 2009, respectively.

Global financial markets may impact our business and financial condition.

Recurrence of a credit crisis or other turmoil in the global financial system may have an impact on our business and our financial condition. 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. Deteriorating economic conditions 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.

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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 and completion services.

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:

- timing of development expenditures;
- amount of required capital expenditures and associated economics;
- recovery efficiencies, decline rates, drainage areas, reservoir limits;
- anticipated reservoir and production characteristics, and interpretations of geologic and geophysical data;
- timing of investments;
- production rates, reservoir pressure, unexpected water encroachment, and other subsurface conditions;
- future oil, gas, and NGL prices;
- effects of governmental regulation;
- future operating costs;
- future property, severance, excise and other taxes incidental to oil and gas operations;

work-over and remedial costs; and

Federal and state income taxes.

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At December 31, 2010, 23% of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 50% are related to a project in Wyoming and 48% 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% of the discounted future net cash flows before income taxes, using a 10% discount rate, as of December 31, 2010.

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.

Our business depends on oil, gas, and NGL 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.

Almost all of the wells we drill 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 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 a material adverse effect on our operations and financial results.

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.

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 15% 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

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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, 2010, our long-term debt consisted of $350 million of unsecured 7.125% Senior Notes. 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, 2010, 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 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, results of operations 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 bears 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;
- 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.

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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.

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

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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 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.

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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 primary objective of the Corporate Reservoir Engineering Group is to maintain accurate forecasts on all properties of the Company through ongoing monitoring and timely updates of operating and economic parameters (production forecasts, prices and regional differentials, operating expenses, ownership, etc.) in accordance with guidelines established by the SEC. This separation of function and responsibility is a key internal control.

Corporate engineers are responsible for the Company's reserve estimates on all properties within specified geographic areas. For both newly drilled and existing properties, corporate engineers interact with the exploration and production departments to ensure all available engineering and geologic data is taken into account prior to establishing or revising a reserve estimate. After preparing the reserve updates, the corporate engineers review their recommendations with the Vice President Corporate Engineering. After the Vice President Corporate Engineering approves the proposed changes, the revisions are entered into the Company's reserve database by the engineering technician.

During the course of the year, the Vice President Corporate Engineering presents summary reserve information to Senior Management and Board of Directors for their review. From time to time, the Vice President Corporate Engineering will also confer with the Vice Presidents of Exploration and Operations, as well as the Chief Executive Officer, regarding specific reserve-related issues. In addition, the Corporate Reservoir Engineering group maintains a set of basic guidelines and procedures to ensure that critical checks and reviews of the reserve database are performed on a regular basis.

Together, these internal controls are designed to promote a comprehensive, objective and accurate reserve estimation process. As an additional confirmation of the reasonableness of the Company's internal reserve estimates an independent petroleum engineering consulting firm reviews properties representing greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex on an annual basis.

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 sixteen 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 six years.

DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, reviewed greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2010. 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-six 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% 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

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further information. The following table sets forth the present value and estimated volume of our oil and gas proved reserves:

	Years Ending December 31, 2010	2009	2008
Total Proved Reserves			
Gas (MMcf)	1,254,166	1,186,585	1,067,333
Oil, (MBbls)	63,656	56,764	44,286
NGL (MBbls)	41,310	1,253	916
Equivalent (MMcfe)	1,883,957	1,534,689	1,338,545
Standardized measure of discounted future net cash flow after-tax, discounted at 10 percent (in thousands)	$ 2,515,277	$ 1,667,955	$ 1,724,253
Average price used in calculation of future net cash flow			
Gas ($/Mcf)	$ 4.12	$ 3.56	$ 5.33
Oil ($/Bbl)	$ 75.35	$ 57.58	$ 36.34
NGL ($/Bbl)	$ 33.89	$ 28.53	$ 24.05

Significant Properties

As of December 31, 2010, 85% of our total proved reserves were located in the Mid-Continent and Permian Basin regions. In total we owned an interest in 12,425 gross (4,798 net) productive oil and gas wells.

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2010.

	Gas (Bcf)	Oil (MBbl)	NGL (MBbl)	Equivalent (Bcfe)	Percent of Proved Reserves
Mid-Continent	756.2	13,255	32,183	1,028.9	55%
Permian Basin	238.5	47,103	6,677	561.2	30%
Gulf Coast	48.8	3,262	2,450	83.1	4%
Wyoming/Other	210.7	36		210.8	11%
	1,254.2	63,656	41,310	1,884.0	100%

Our ten largest producing fields hold 45% 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	Average Working Interest %	Approximate Average Depth (feet)	Primary Formation
Watonga-Chickasha (Cana)	Mid-Continent	26.7	42.8	13,000'	Woodford
Hemphill	Mid-Continent	2.9	94.5	11,000'	Granite Wash
Eola-Robberson	Mid-Continent	2.8	89.0	5,500' - 11,000'	Bromide/McLish/Oil Creek
Phantom	Permian Basin	2.4	95.7	11,500'	Bone Spring
Mendota NW	Mid-Continent	2.3	65.3	11,000'	Granite Wash
Constitution	Gulf Coast	2.2	94.6	14,000'	Yegua
Caprock	Permian Basin	1.6	80.3	9,000'	Abo
Quail Ridge	Permian Basin	1.6	76.1	8,000' - 13,000'	Bone Spring/Morrow
Jo-Mill	Permian Basin	1.4	12.9	7,500'	Spraberry
Two Georges	Permian Basin	0.8	91.5	11,500'	Bone Spring

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Acreage

The following table sets forth as of December 31, 2010, 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.

	Acreage					
	Undeveloped		Developed		Total	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent						
Kansas	20,882	18,281	145,819	103,178	166,701	121,459
Oklahoma	222,776	164,078	476,341	228,233	699,117	392,311
Texas	128,547	112,747	197,775	123,234	326,322	235,981
	372,205	295,106	819,935	454,645	1,192,140	749,751
Permian Basin						
New Mexico	144,187	96,214	178,285	123,866	322,472	220,080
Texas	146,761	111,011	177,298	117,147	324,059	228,158
	290,948	207,225	355,583	241,013	646,531	448,238
Gulf Coast						
Louisiana	7,665	3,193	17,684	4,858	25,349	8,051
Texas	61,701	32,493	107,855	45,514	169,556	78,007
Offshore	35,900	16,007	128,875	40,799	164,775	56,806
	105,266	51,693	254,414	91,171	359,680	142,864
Western/Other						
Arkansas	948	783	4,184	1,596	5,132	2,379
Arizona	2,115,100	2,115,100			2,115,100	2,115,100
California	397,831	397,831	364	364	398,195	398,195
Colorado	154,712	66,455	26,809	5,818	181,521	72,273
Illinois	1,902	1,251	391	20	2,293	1,271
Michigan	38,967	38,889	1,185	1,185	40,152	40,074
Montana	38,993	11,893	10,220	2,749	49,213	14,642
Nebraska	9,268	1,044	1,043	168	10,311	1,212
Nevada	1,007,167	1,007,167	440	1	1,007,607	1,007,168
New Mexico	1,653,440	1,639,074	19,688	2,643	1,673,128	1,641,717
North Dakota	50,437	12,087	7,286	1,039	57,723	13,126
South Dakota	9,666	9,134	2,015	364	11,681	9,498
Texas	63,868	63,382			63,868	63,382
Utah	88,452	59,343	29,970	1,692	118,422	61,035
Wyoming	168,838	22,396	71,618	9,493	240,456	31,889
	5,799,589	5,445,829	175,213	27,132	5,974,802	5,472,961
Total	6,568,008	5,999,853	1,605,145	813,961	8,173,153	6,813,814

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The table below summarizes by year and region our undeveloped acreage expirations in the next five years. In most cases the drilling of a commercial well will hold the acreage beyond the expiration.

	Undeveloped Acres Expiring									
	2011		2012		2013		2014		2015	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	45,099	40,987	2,948	1,778	35,817	34,279			491	487
Permian Basin	23,257	22,730	15,295	14,879	39,544	39,538	3,234	3,234	21,659	19,705
Gulf Coast	13,133	13,113	6,021	5,988	3,451	2,677			6	6
Western/Other	30,707	30,115	4,357	3,318	111,037	111,037	14,806	14,766	19,122	19,122
	112,196	106,945	28,621	25,963	189,849	187,531	18,040	18,000	41,278	39,320
Percent of undeveloped	1.7	1.8	0.4	0.4	2.9	3.1	0.3	0.3	0.6	0.7

Gross Wells Drilled

We participated in drilling the following number of gross wells during calendar years 2010, 2009, and 2008:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2010	10	3	13	199	7	206
Year ended December 31, 2009	7	4	11	95	4	99
Year ended December 31, 2008	36	16	52	384	14	398

We were in the process of drilling 32 gross (26.6 net) wells at December 31, 2010 and there were 43 gross (23 net) wells waiting on completion.

Net Wells Drilled

The number of net wells we drilled during calendar years 2010, 2009, and 2008 are shown below:

	Exploratory			Developmental		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2010	9.4	3.0	12.4	111.4	5.2	116.6
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

Productive Wells

We have working interests in the following productive wells as of December 31, 2010:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	4,067	2,119	1,182	586
Permian	1,045	575	5,245	1,296
Gulf Coast	335	127	442	90
Other	79	4	30	1
	5,526	2,825	6,899	1,973

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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. We had a judgment of $119.6 million, of which $6.9 million pertained to damages, with the remainder being disgorgement of H&P's estimated potential compounded profit since 1989 resulting from the noted damages. 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 and 2010, we have accrued additional interest and fees of $9.4 million and $8.9 million, respectively. 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. 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 4A. EXECUTIVE OFFICERS

The executive officers of Cimarex as of February 25, 2011 were:

Name	Age	Office
F.H. Merelli	74	Chairman of the Board, Chief Executive Officer, and President
Joseph R. Albi	52	Executive Vice President, Operations
Thomas E. Jorden	53	Executive Vice President, Exploration
Stephen P. Bell	56	Senior Vice President, Business Development and Land
Paul Korus	54	Senior Vice President and Chief Financial Officer
Gary R. Abbott	38	Vice President, Corporate Engineering
Richard S. Dinkins	66	Vice President, Human Resources
James H. Shonsey	59	Vice President, Chief Accounting Officer, and Controller
Thomas A. Richardson	65	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

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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 named senior vice president in December 2010 after having served in a similar role as vice president and chief financial officer of Cimarex since September 2002. From June 1999 to September 2002, Mr. Korus was vice president and chief financial officer of Key Production Company. Prior to Key, he was an equity research analyst with an energy investment banking firm from 1995 to 1999 and was with Apache Corporation from 1982 to 1995.

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.

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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 was paid to shareholders in each quarter of 2010. 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.

2010	**High**	**Low**	**Dividends Paid Per Share**
First Quarter	$ 63.09	$ 48.68	$ .06
Second Quarter	$ 81.50	$ 58.64	$ .08
Third Quarter	$ 77.11	$ 62.88	$ .08
Fourth Quarter	$ 90.86	$ 65.48	$ .08

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

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 18, 2011, was $114.62. At December 31, 2010, Cimarex's 85,234,721 shares of outstanding common stock were held by approximately 2,731 stockholders of record.

The following graph compares the cumulative 5-year total return attained by shareholders on Cimarex Energy Co.'s common stock relative to 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 12/31/2005 to 12/31/2010.

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COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

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

*$100 invested on 12/31/05 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

	12/05	12/06	12/07	12/08	12/09	12/10
Cimarex Energy Co.	100.00	85.21	99.70	63.12	125.78	211.15
S&P 500	100.00	115.80	122.16	76.96	97.33	111.99
Dow Jones US Exploration & Production	100.00	105.37	151.39	90.65	127.42	148.74

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 2010, or since the quarter ended September 30, 2007.

Issuer Purchases of Equity Securities for the Quarter Ended December 31, 2010

	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, 2010	None	NA	None	2,635,700
November, 2010	None	NA	None	2,635,700
December, 2010	None	NA	None	2,635,700

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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,				
	2010	2009	2008	2007	2006
	(In thousands, except per share amounts)				
Operating results:					
Revenues	$ 1,613,683	$ 1,009,794	$ 1,970,347	$ 1,430,513	$ 1,265,400
Net income (loss)	574,782	(311,943)	(915,245)	345,262	344,481
Earnings (loss) per share to common Stockholders:					
Basic					
Distributed	$ 0.32	$ 0.24	$ 0.24	$ 0.18	$ 0.16
Undistributed	6.42	(4.06)	(11.46)	3.97	3.96
	$ 6.74	$ (3.82)	$ (11.22)	$ 4.15	$ 4.12
Diluted					
Distributed	$ 0.32	$ 0.24	$ 0.24	$ 0.18	$ 0.16
Undistributed	6.38	(4.06)	(11.46)	3.87	3.89
	$ 6.70	$ (3.82)	$ (11.22)	$ 4.05	$ 4.05
Cash dividends declared per share	0.32	0.24	0.24	0.18	0.16
Balance sheet data:					
Total assets	$ 4,358,247	$ 3,444,537	$ 4,164,933	$ 5,362,794	$ 4,829,750
Total debt	$ 350,000	$ 392,793	$ 587,630	$ 462,216	$ 416,823
Stockholders' equity	$ 2,609,832	$ 2,038,106	$ 2,351,647	$ 3,275,128	$ 2,993,192
Other financial data:					
Commodity sales	$ 1,558,562	$ 962,443	$ 1,880,891	$ 1,364,622	$ 1,215,411
Oil and gas capital expenditures	$ 1,038,706	$ 528,041	1,620,778	1,023,434	$ 1,074,673
Proved Reserves:					
Gas (MMcf)	1,254,166	1,186,585	1,067,333	1,122,694	1,090,362
Oil (MBbls)	63,656	56,764	44,286	57,150	58,932
NGL (MBbls)	41,310	1,253	916	1,100	865
Total equivalent (MMcfe)	1,883,957	1,534,689	1,338,545	1,472,195	1,449,146

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 2010 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.

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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 property acquisitions. Our growth is generally funded with cash flow provided by our operating activities. In order 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 conducted in Texas, Oklahoma and New Mexico. We also have projects in Kansas and Wyoming.

Our revenue, profitability and future growth are highly dependent on the commodity prices we receive. Continued volatility in commodity prices, and a recurrence of 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.

Our ability to find, develop and/or acquire proved oil and gas reserves will also impact our financial results. 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.

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, equity and proved reserves. We use the full cost method of accounting for oil and gas activities.

2010 Summary:

For the year-ended December 31, 2010, net income totaled $574.8 million, or $6.70 per diluted share. This compares to a loss of $311.9 million, or $3.82 per share for 2009. Cash flow provided by operating activities totaled $1.1 billion, up from $675.2 million in 2009. Our proved reserves grew 23% and our production volume increased 29%. We anticipate production growth of 3 - 8% for 2011.

Our 2010 drilling activities have been conducted in three main areas: Permian Basin, Mid-Continent and Gulf Coast. We drilled and completed 219 gross (129 net) wells during 2010, and at year-end we had 23 operated rigs running.

2010 summary operating and financial results:

Proved reserves increased 23% to 1.88 Tcfe, up from 1.53 Tcfe in 2009.

Daily production volumes increased 29% to 595.9 MMcfe/d, up from 462.9 MMcfe/d for 2009.

Oil, gas and NGL sales increased 62% to $1.559 billion compared to $962.4 million a year earlier.

Our average realized oil price increased 36% to $76.76 per barrel compared to $56.63 per barrel in 2009.

Our average realized gas price increased 19% to $4.92 per Mcf versus $4.12 per Mcf in 2009.

Average realized NGL prices decreased 6% to $34.91 per barrel compared to $37.11 per barrel in 2009.

Total debt decreased by $42.8 million to $350 million compared to $392.8 million at year-end 2009.

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Cash and cash equivalents totaled $114.1 million at December 31, 2010, up from $2.5 million at the end of 2009.

In response to higher oil and gas prices we significantly increased our 2010 exploration and development capital expenditures. In 2010 our exploration and development expenditures were $998.9 million. Total expenditures for 2009 were $524.4 million.

In October 2010 our bank group, as part of its regularly scheduled fall review, reaffirmed our $1.0 billion borrowing base related to our credit facility. Bank group commitments to lend up to $800 million also remain unchanged. At December 31, 2010, we did not have any bank borrowings outstanding. At December 31, 2009 we had bank borrowings outstanding of $25 million.

During 2010 we made property acquisitions of $39.8 million, primarily for additional interests in our western Oklahoma, Cana-Woodford shale play. We made no significant acquisitions during 2009. During 2010 we sold oil and gas properties for $28.2 million, most of which were located in Mississippi. In 2009 we sold various non-core properties for $109.4 million, the largest of which was a West Texas secondary oil recovery field.

Commodity Prices

While our revenues are a function of both production and prices, wide swings in commodity prices have had the greatest impact on our results of operations. Commodity 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 and energy demand caused significant decreases in commodity prices. Year end 2008 prices fell 50-70% from their mid-2008 peak.

As 2009 unfolded, oil and NGL prices improved, but they remained well below prior year levels. The downward pressure on natural gas prices continued in 2009, resulting in an average realized price 51% lower than that of 2008.

Oil prices have continued to improve during 2010, as the US and global economic situation have improved. However, there is still significant volatility as a result of concerns about sustained economic growth and geopolitical instability. Prices for natural gas have remained low, primarily as a result of an oversupply.

The following table presents our average realized commodity prices for the years ended 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	**2009**	**2008**
Gas Prices:			
Average Henry Hub price ($/Mcf)	$ 4.39	$ 3.99	$ 9.04
Average realized sales price ($/Mcf)	$ 4.92	$ 4.12	$ 8.43
Effect of hedges ($/Mcf)	$	$	$ 0.09
Oil Prices:			
Average WTI Cushing price ($/Bbl)	$ 79.54	$ 61.81	$ 99.65
Average realized sales price ($/Bbl)	$ 76.76	$ 56.63	$ 96.76
NGL Prices:			
Average realized sales price ($/Bbl)	$ 34.91	$ 37.11	$ 57.10

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On an energy equivalent basis, 61% of our 2010 aggregate production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in a $13.3 million change in our gas revenues. Similarly, 39% of our production was crude oil and NGL. A $1.00 per barrel change in our average realized sales price would have resulted in a $14.1 million change in our oil and NGL 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 2009 we entered into derivative contracts covering approximately 40% of our anticipated 2010 oil and gas production volumes. These contracts were settled in 2010 for a net gain of $52.1 million.

During 2010 we entered into oil and gas contracts relative to our 2011 production which equate to approximately 40 to 45% of our anticipated 2011 oil production and 5 to 6% of projected gas production. Management has been authorized to hedge up to 50% of our anticipated equivalent production. At December 31, 2010, we had the following outstanding contracts:

Natural Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Swap
Jan 11 - Dec 11	Swap	20,000 MMBtu	PEPL	$ 5.05

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling
Jan 11 - Dec 11	Collar	12,000 Bbls	WTI	$ 65.00	$ 105.44

(1) PEPL refers to Panhandle Eastern Pipe Line Company price 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.

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

We have chosen not to apply hedge accounting treatment to any of the derivative contracts we entered into in 2009 and 2010. Therefore, settlements on these contracts do not impact our realized commodity prices during the periods they cover. Instead, any settlements on the contracts are shown as a component of operating costs and expenses as either a net gain or loss on derivative instruments. See Item 7A and Note 4 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Reserve replacement and growth

Oil and gas are non-renewable forms of energy resources. Therefore, exploration and production companies face the challenge of resource depletion and natural production decline. For most years our primary source of reserve replacement and growth is exploration and development ("E&D"). Our E&D expenditures are generally funded with cash flow provided by operating activities.

A cornerstone of our approach to reserve replacement is a detailed evaluation of each drilling decision based on its risk-adjusted discounted cash flow rate of return on investment. We analyze and project potential reserve size, geologic and mechanical risks, expected costs, future production profiles and future commodity prices. Our operations 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.

In order to achieve a consistent rate of growth and mitigate risk we have historically maintained a blended portfolio of low, moderate, and higher risk E&D projects. To further mitigate risk, we have chosen to seek geologic and geographic diversification by operating in multiple basins.

Our E&D capital expenditures for 2010 totaled $998.9 million. Approximately 45% of our expenditures were in our Mid-Continent region, 42% in the Permian Basin and 12% in our Gulf Coast region. Cash flow from operating activities for 2010 totaled $1.1 billion, which more than funded our drilling program.

Year end 2010 proved reserves grew 23% to 1.88 trillion cubic feet equivalent (Tcfe), up from 1.53 Tcfe at year-end 2009. Reserve additions were comprised of 66% oil and NGL and 34% gas, resulting in proved reserves going from 77% gas at year-end 2009 to 67% at year-end 2010. Proved reserves are 77% developed for both year-end 2010 and year-end 2009.

The increase in 2010 proved reserves is net of production of 217.5 billion cubic feet equivalent (Bcfe) and property sales of 8.7 Bcfe. Reserves added from E&D totaled 411.7 Bcfe and 15.4 Bcfe were acquired via property purchases. Net revisions added 148.4 Bcfe, which included 44.8 Bcfe driven by higher commodity prices. The rest of the increase relates primarily to increases in our NGL volumes. The determination of whether to record NGL production volumes is based on where title transfer occurs. Ongoing contractual amendments together with increased gas production volumes with high NGL content have contributed to higher estimated NGL reserves.

Overall, approximately 55% of our proved reserves are in our Mid-Continent region and 30% are in the Permian Basin. Our onshore Gulf Coast and other onshore operations collectively make up another 15% of total proved reserves. Less than 1% of our total proved reserves are in the Gulf of Mexico.

We expect our 2011 E&D capital expenditures to be principally funded from cash flow. Based on current market prices and service costs, we expect that 2011 E&D expenditures may range from $1.2 to $1.4 billion. At year-end 2010 we have a large inventory of drilling opportunities and limited lease expirations. Our future growth will continue to depend upon our ability to economically add reserves in excess of production.

There is strong competition in all sectors of the oil and gas industry. We compete with major integrated and other independent oil and gas companies for the acquisition of oil and gas leases and properties. We also compete for the equipment and personnel required to explore, develop and operate properties. Strong competition also exists in the marketing of oil, NGL and gas. Higher commodity prices will generally increase the costs of properties available for acquisition. Many of our competitors have financial and other resources substantially greater than ours. As a consequence, we could be at a competitive disadvantage in conducting our business. To assure timely execution of our drilling program we occasionally enter into contractual arrangements with certain service providers to secure equipment and supplies for future periods.

Our business is subject to extensive federal, state and local rules and regulations, some of which have substantial penalties for failure to comply. Changes in public policy could affect the profitability of our operations and our ability to economically replace reserves. See Item 1 of this report for further information regarding government regulations.

The process of estimating quantities of oil, gas and NGL 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, contractual arrangements 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 our reserve estimates 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.

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 2010, we owned interests in 12,425 gross wells.

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 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, restricted stock units and stock options. In accordance with our stock incentive plan, such grants are periodically made to non-employee directors, officers and other eligible employees.

The net gain or loss on derivative instruments is the net realized and unrealized gain or loss on derivative contracts, to which we did not apply hedge accounting treatment. That amount will fluctuate based on changes in the fair values of the underlying commodities.

RESULTS OF OPERATIONS

2010 compared to 2009

For the year-ended December 31, 2010, net income totaled $574.8 million, or $6.70 per diluted share. This compares to a net loss of $311.9 million, or $3.82 per share for 2009. The increase in net income results from increased production and the improvement of realized oil and gas prices. In addition, in 2009 we recorded a $791.1 million non-cash full cost ceiling write-down, which was the main reason for the net loss in 2009. These changes are discussed further in the analysis that follows.

Commodity Sales	For the Years Ended December 31, 2010	2009	Percent Change Between 2010/2009	Price / Volume Analysis Price	Volume	Variance
(In thousands or as indicated)						
Gas sales	$ 653,793	$ 485,448	35%	$ 106,250	$ 62,095	$ 168,345
Oil sales	755,618	468,833	61%	198,160	88,625	286,785
NGL sales	149,151	8,162	1727%	(9,398)	150,387	140,989
Total commodity sales	$ 1,558,562	$ 962,443	62%	$ 295,012	$ 301,107	$ 596,119
Total gas volume MMcf	132,813	117,968	13%			
Gas volume MMcf per day	363.9	323.2				
Average gas price per Mcf	$ 4.92	$ 4.12	19%			
Total oil volume thousand barrels	9,844	8,278	19%			
Oil volume barrels per day	26,969	22,681				
Average oil price per barrel	$ 76.76	$ 56.63	36%			
Total NGL volume thousand barrels	4,272	220	1842%			
NGL volume barrels per day	11,705	603				
Average NGL price per barrel	$ 34.91	$ 37.11	-6%			

Commodity sales during 2010 totaled $1.6 billion, compared to $962.4 million in 2009. Approximately 51% of the $596.1 million increase between the two periods resulted from higher production volumes. The remainder of the increase was due to higher realized oil and gas prices, which had a positive impact of $304.4 million.

Our full year 2010 gas production averaged 363.9 MMcf per day, compared to 323.2 MMcf per day for 2009. This 13% increase resulted in $62.1 million of incremental revenue for 2010. During the fourth quarter of 2010 our daily gas production averaged 341.5 MMcf per day, up slightly from 330.0 MMcf per day for the fourth quarter of 2009. This 3% increase contributed $5.6 million of additional revenues for the fourth quarter of 2010.

Oil production for 2010 averaged 26,969 barrels per day. For 2009 our average daily oil production was 22,681 barrels per day. The year over year increase of 19% in 2010 daily production contributed an additional $88.6 million of revenue for the year. Our fourth quarter 2010 oil production averaged 27,137 barrels per day, or an increase of 22% compared to average daily production of 22,309 barrels for the fourth quarter of 2009. The higher production in the fourth quarter of 2010 increased oil sales by $32.4 million.

During 2010 we began separately reporting NGL volumes. The determination of whether to record and separately disclose NGL volumes is based on where title transfer occurs during processing of the well stream. New gas processing contracts and certain contractual amendments resulted in title of NGL volumes transferring to the Company.

Our average daily NGL production volumes were 11,705 barrels per day. This compares to average daily NGL volumes for all of 2009 of 603 barrels per day. The higher production volumes in 2010 contributed an additional $150.4 million of revenue. For the fourth quarter of 2010 our average daily NGL production was 16,702 barrels per day, up from 626 barrels per day during the fourth quarter of 2009. This increase provided an additional $71.8 million of revenue in the fourth quarter of 2010.

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Overall, increases in our 2010 production volumes primarily reflect positive drilling results in our western Oklahoma Cana-Woodford shale play, our Permian Basin oil programs and our Yegua/Cook Mountain play in southeast Texas.

Our average realized gas price for 2010 increased by 19% to $4.92 per Mcf, compared to $4.12 per Mcf in 2009. This price increase contributed $106.3 million to gas sales in 2010.

During the fourth quarter of 2010 our average realized gas price fell to $4.18 per Mcf. For the same period of 2009, we realized an average price per Mcf of $5.30. The decrease in prices received in the fourth quarter of 2010 resulted in $35.2 million less in gas sales compared to the same period of 2009.

Realized oil prices during all of 2010 averaged $76.76 per barrel, an increase of 36% over the average price received for oil in 2009 of $56.63 per barrel. This increase resulted in an additional $198.2 million of oil sales in 2010. For the fourth quarter of 2010 our average realized oil price was $82.33 per barrel versus $72.93 per barrel received in the fourth quarter of 2009. The increase in fourth quarter 2010 oil sales due to the 13% increase in oil prices totaled $23.5 million.

During 2010 our NGL average realized price was $34.91 per barrel. In 2009 we realized $37.11 per barrel. The drop in realized price resulted in a decrease of $9.4 million for NGL sales in 2010. For the fourth quarter of 2010 our average realized price for NGL was $37.59 per barrel, or 23% less than the average realized price of $48.57 per barrel received for the same period of 2009. The decrease in fourth quarter 2010 NGL sales attributed to the decline in price was $16.9 million.

Increases and decreases in realized commodity prices were the result of supply and demand factors and overall market conditions. There continues to be significant upward volatility in oil prices stemming from concerns about sustained economic growth and geopolitical instability. Abundant domestic supplies of natural gas have continued to dampen prices in the first quarter of 2011.

	For the Years Ended December 31,	
	2010	**2009**
Gas Gathering, Processing and Marketing (in thousands):		
Gas gathering, processing and other revenues	$ 54,662	$ 46,763
Gas gathering and processing costs	(22,162)	(20,560)
Gas gathering and processing margin	$ 32,500	$ 26,203
Gas marketing revenues, net of related costs	$ 459	$ 588

We sometimes transport, process and market third-party gas that is associated with our gas. In 2010, third-party gas gathering, processing and other contributed $32.5 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $26.2 million in 2009. Our gas marketing margin (revenues less purchases) decreased 22% to $459 thousand in 2010 from $588 thousand in 2009. Changes in net margins

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from gas gathering, processing, marketing and other activities are the direct result of volumetric changes and overall market conditions.

	For the Years Ended December 31, 2010	For the Years Ended December 31, 2009	Variance Between 2010/2009
Operating costs and expenses (in thousands):			
Impairment of oil and gas properties	$	$ 791,137	$ (791,137)
Depreciation, depletion and amortization (DD&A)	304,222	265,699	38,523
Asset retirement obligation	7,322	12,313	(4,991)
Production	194,015	178,215	15,800
Transportation	49,968	33,758	16,210
Taxes other than income	121,781	75,634	46,147
General and administrative	48,620	41,724	6,896
Stock compensation, net	12,353	9,254	3,099
(Gain) loss on derivative instruments, net	(62,696)	13,059	(75,755)
Other operating, net	4,575	24,263	(19,688)
	$ 680,160	$ 1,445,056	$ (764,896)

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) decreased to $680.2 million in 2010 compared to $1.4 billion in 2009. The largest component of the change between periods is the non-cash impairment of oil and gas properties of $791.1 million recorded in the first quarter of 2009. The impairment resulted from a ceiling test write-down as a result of declines in natural gas prices during the first quarter of 2009. The full cost method of accounting is discussed in detail under "Critical Accounting Policies and Estimates" in this report.

Operating costs and expenses for 2010 compared to 2009 costs of $653.9 million (excluding the $791.1 million impairment) increased by $26.2 million, or 4%. Analyses of the year over year differences are discussed below.

DD&A increased $38.5 million from $265.7 million in 2009 to $304.2 million in 2010. On a unit of production basis, DD&A was $1.40 per Mcfe in 2010 compared to $1.57 per Mcfe for 2009. The lower DD&A rate was a result 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. The decrease in expense resulting from the 11% decrease in the DD&A rate per Mcfe was more than offset by increased expense related to higher production volumes for 2010.

Asset retirement obligation expense declined 41% from $12.3 million in 2009 to $7.3 million in 2010. The decrease was primarily due to certain plugging and abandonment costs in 2009 that exceeded our original asset retirement obligation estimates. This occurred because of hurricane damage to our offshore properties which caused additional expenses to be incurred during site restoration.

Our production costs consist of lease operating expense and workover expense. Our aggregate costs for 2010 of $194 million were 9% higher than 2009 aggregate costs of $178.2 million. Approximately 61% of the aggregate increase relates to higher operating expense associated primarily with new wells we've drilled in 2009 and 2010. Our workover expenditures in 2010 accounted for the remainder of the increase. Our average cost per Mcfe decreased $0.16, from $1.05 per Mcfe in 2009 to $0.89 per Mcfe in 2010. The decrease in rate resulted from our continued focus on efficiencies in production operations. However, we expect to see our production cost per Mcfe begin to trend upward, due to expected increases in certain service costs.

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Transportation costs rose to $50 million ($0.23 per Mcfe) for 2010 from $33.8 million ($0.20 per Mcfe) in 2009. Transportation costs will fluctuate based on increases or decreases in sales volumes and fluctuation in the price of the fuel cost component. Also, during 2010 we recorded $1.7 million of well connection reimbursement costs. These costs resulted from a failure to meet minimum volume delivery commitments entered into in prior years.

Taxes other than income increased $46.1 million from $75.6 million in 2009 to $121.8 million in 2010. The increased taxes resulted from increases in production volumes and from higher realized commodity prices in 2010.

Our general and administrative expense was $48.6 million in 2010 compared to $41.7 million for 2009. The $6.9 million increase is mostly due to higher costs associated with employee-benefits, including bonus and profit sharing expenses, in 2010.

Stock compensation expense, net consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units and stock option awards, net of amounts capitalized. Net stock compensation expense in 2010 was $12.4 million compared to $9.3 million in 2009. Expense associated with stock compensation will fluctuate based on the grant date market value of the award and the number of awards granted. (See Note 9 to the Consolidated Financial Statements of this report for a detailed discussion regarding our stock-based compensation).

Our net (gain) or loss on derivative instruments includes both realized gains and losses on settlements of our derivative contracts and unrealized gains and losses stemming from changes in the fair value of our outstanding derivative instruments. We estimate the fair values of these instruments based on published forward commodity price curves for the underlying commodity as of the date of the estimate. For collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. The fair values of our derivative instruments in an asset position include a measure of counterparty credit risk, and the fair values of instruments in a liability position include a measure of our own nonperformance risk. These credit risks are based on current published credit default swap rates. We did not elect hedge accounting treatment for derivative contracts that we entered into in 2010 and 2009. (See Note 4 to the Consolidated Financial Statements in this report for a complete discussion of our derivative instruments).

The following table reflects the net realized and unrealized (gains) and losses on our derivative instruments:

	For the Years Ended December 31,	
	2010	**2009**
	(In thousands)	
Realized (gain) loss on settlement of derivative instruments	$ (52,098)	$ (1,394)
Unrealized (gain) loss from changes to the fair value of the derivative instruments	(10,598)	14,453
(Gain) loss on derivative instruments, net	$ (62,696)	$ 13,059

Other operating, net consists of costs related to various legal matters, most of which pertain to litigation and contract settlements and title and royalty issues. Our Other operating net costs decreased from $24.3 million in 2009 to $4.6 million for 2010. The decrease was mainly a result of less litigation accruals and fewer contract settlements in 2010 and the favorable resolution of items in 2010 that had been accrued for in prior years. For further information on litigation matters please see Contingencies under "Critical Accounting Policies and Estimates" in this report.

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Other income and expense

Our 2010 interest expense was $36.6 million compared to $39.8 million for 2009. The $3.2 million decrease resulted from lower average bank debt outstanding during 2010 compared to 2009. During 2010 we only had bank borrowings outstanding in the first quarter of the year. This resulted in average daily bank debt outstanding of $4.5 million for 2010. During 2009 our average daily bank debt outstanding was $269.6 million.

Capitalized interest for 2010 increased by $5.8 million to $29.2 million, compared to $23.4 million in 2009. The increase results from more costs associated with our unproved properties and construction project in 2010 and a higher average interest rate for 2010 versus 2009.

In July of 2010, holders of our floating rate convertible senior notes elected to convert their notes for cash and shares of our common stock. We recorded a gain of $3.8 million on the early extinguishment of the notes. (See Note 7 to the Consolidated Financial Statements of this report for a complete discussion of our convertible notes).

Components of other, net consist of miscellaneous income and expense items that will vary from period to period, including, gain or loss on the sale or value of oil and gas well equipment, interest income, and income or loss from equity investees. Other, net increased from $16.3 million of expense in 2009 to $6 million of income in 2010. Approximately 68% of the $22.3 million change from 2009 to 2010 is attributable to losses in 2009 related to oil and gas well equipment. In 2009 the value of drill pipe decreased due to the significant slowing of drilling activity across the industry. Another 24% of the change resulted from gains on fixed asset sales during 2010.

Income tax

For the year ended December 31, 2010, we recognized net income tax expense of $338.9 million (of which $46.3 million is current). This compares with a 2009 net income tax benefit of $176.5 million (including a current tax benefit of $11.8 million). The combined Federal and state effective income tax rates were 37.1% for 2010 and 36.1% for 2009. The effective tax rate of 37.1% for 2010 differs from the statutory rate of 35% due to the effects of state income taxes, the Domestic Production Activities allowance and other permanent differences.

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

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

Commodity Sales	For the Years Ended December 31, 2009	2008	Percent Change Between 2009/2008	Price / Volume Analysis Price	Volume	Variance
(In thousands or as indicated)						
Gas sales	$ 485,448	$ 1,074,705	-55%	$ (508,442)	$ (80,815)	$ (589,257)
Oil sales	468,833	797,382	-41%	(332,196)	3,647	(328,549)
NGL Sales	8,162	8,804	-7%	(4,398)	3,756	(642)
Total commodity sales	$ 962,443	$ 1,880,891	-49%	$ (845,036)	$ (73,412)	$ (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	$	$ 0.09				
Total oil volume thousand barrels	8,278	8,241	%			
Oil volume barrels per day	22,681	22,516				
Average oil price per barrel	$ 56.63	$ 96.76	-41%			
Total NGL volume thousand barrels	220	154	43%			
NGL volume barrels per day	603	421				
Average NGL price per barrel	$ 37.11	$ 57.10	-35%			

Commodity 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, $845 million related to lower prices and $73.4 million resulted from lower production volumes.

Compared to 2008, our 2009 oil production increased by 1% to an average of 22,681 barrels per day. This increase resulted in $3.6 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. NGL volumes increased to 603 barrels per day in 2009 compared to 421 barrels per day in 2008. This resulted in increased commodity sales of $3.8 million for 2009. Total 2009 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 6% decrease) from the fourth quarter of 2008. Fourth quarter oil production decreased by 5% to 22,309 barrels per day from 23,429 barrels per day in 2008. Fourth quarter NGL production increased by 31% to 626 barrels per day from 478 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 $56.63 per barrel during 2009, compared to $96.76 per barrel in 2008. The decrease in oil sales resulting from this 41% decline in oil prices totaled $332.2 million.

Our average realized price for NGL during 2009 was $37.11 per barrel. In 2008 the average NGL price was $57.10 per barrel. The decrease in our average realized price resulted in lower NGL sales of $4.4 million.

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The decreases in realized commodity prices were the result of overall market conditions.

	For the Years Ended December 31, 2009	For the Years Ended December 31, 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

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, 2009	For the Years Ended December 31, 2008	Variance Between 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 gas 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%, 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.

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 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.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units and stock option awards. Net stock compensation expense in 2009 was $9.3 million compared to $10.1 million in 2008. Expense associated with stock compensation will fluctuate based on the grant date market value of the award and the number of awards granted. (See Note 9 to the Consolidated Financial Statements in this report for a detailed discussion regarding our stock-based compensation).

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.

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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.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity is highly dependent on the commodity prices we receive. Oil and gas markets are very volatile and we cannot predict future commodity prices. The prices we receive for our production heavily influence our revenue, profitability, access to capital and future rate of growth. During 2010 the United States and global economy have shown improvement. However, concerns about a recurrence of turmoil in the global financial system and geopolitical instability have continued to impact commodity prices, particularly the price of oil. Prices for natural gas have continued to be depressed, primarily as a result of an oversupply of natural gas coupled with lower demand. Volatility in commodity prices may reduce the amount of oil and gas that we can economically produce and affect the amount of cash flow available for capital expenditures. Disruptions in economic conditions may impact third parties with whom we do business, causing them to fail to meet their obligations to us.

We intend to deal with volatility in the current economic environment by maintaining a blended portfolio of low, moderate and higher risk exploration and development projects. Our drilling activities are currently being conducted in three main areas: the Permian Basin, Mid-Continent and Gulf Coast. Our Permian activity is directed primarily to the Delaware Basin of southeast New Mexico and West Texas. The majority of our Mid-Continent drilling is in the western Oklahoma Cana-Woodford shale and Texas Panhandle Granite Wash. Our Gulf Coast operations are currently focused in southeast Texas, near Beaumont.

Historically our exploration and development expenditures have generally been funded by cash flow provided by operating activities ("operating cash flow"). During 2010 we have continued to fund our exploration and development expenditures with operating cash flow. We also intend to continue to use debt sparingly and hedge a portion of our production, to protect our operating cash flow for reinvestment.

From time to time we consider attractive acquisition opportunities. However, the timing and size of acquisitions are unpredictable. To prepare ourselves for potential acquisitions and potential declines in commodity prices, we have a three-year senior secured revolving credit facility. The credit facility provides for bank commitments of $800 million with a borrowing base of $1 billion.

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At December 31, 2010, our total debt outstanding was $350 million, which is comprised of our 7.125% Notes due in 2017. Our debt to total capitalization ratio at year-end was 12%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $350 million divided by long-term debt of $350 million plus stockholders' equity of $2.610 billion. Management believes that this non-GAAP measure is useful information for investors because it is a common statistic referred to by the investment community, used to identify the amount of our leverage and to help analyze our risk exposure relative to other companies in the oil and gas exploration and production industry.

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 2011 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, development and other capital expenditures, property acquisitions, common stock dividends and occasional share repurchases.

The following table presents the sources and uses of our cash and cash equivalents from 2008 to 2010. 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,		
	2010	2009	2008
		(in thousands)	
Sources of cash and cash equivalents:			
Operating cash flow	$ 1,130,432	$ 675,177	$ 1,367,488
Sales of oil and gas and other assets	34,075	119,735	39,096
Net increase in bank debt			220,000
Distributions from equity investees			39
Sales of short-term investments		3,328	10,679
Issuance of common stock and other	28,758	3,421	13,141
Total sources of cash and cash equivalents	1,193,265	801,661	1,650,443
Uses of cash and cash equivalents:			
Oil and gas expenditures	(959,751)	(535,308)	(1,594,775)
Other expenditures	(51,882)	(31,849)	(51,757)
Net decrease in bank debt	(25,000)	(195,000)	
Decrease in other long-term debt	(19,450)		(105,550)
Financing costs incurred	(101)	(18,001)	(158)
Dividends paid	(25,499)	(20,172)	(20,040)
Total uses of cash and cash equivalents	(1,081,683)	(800,330)	(1,772,280)
Net increase (decrease) in cash and cash equivalents	$ 111,582	$ 1,331	$ (121,837)
Cash and cash equivalents at end of year	$ 114,126	$ 2,544	$ 1,213

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

Cash flow provided by operating activities for 2010 was $1.1 billion compared to $675.2 million for 2009 and $1.4 billion for 2008. The increase from 2009 to 2010 resulted primarily from higher realized oil and gas prices together with higher production during 2010. The decrease from 2008 to 2009 resulted primarily from lower realized commodity prices and decreased gas production.

Cash flow used in investing activities for 2010 was $977.6 million, compared to $444.1 million for 2009 and $1.6 billion for 2008. Changes in the cash flow used in investing activities are generally the result of changes in our exploration and development programs, property acquisitions and sales and other capital expenditures.

The increase in cash flow used in investing activities from 2009 to 2010 was mostly from increased oil and gas expenditures resulting from a more active drilling program in 2010. Also, we had $85.6 million less proceeds from asset sales in 2010 compared to 2009. The decrease from 2008 to 2009 was primarily a result of 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. In addition, 2009 had $80.6 million more proceeds from asset sales than there were in 2008.

Net cash flow used in financing activities in 2010 was $41.3 million compared to $229.8 million in 2009. In 2008 we had net cash flow provided by financing activities of $107.4 million. In 2010 we had payments of bank and other long-term debt of $44.5 million. In 2010 we also paid dividends of $25.5 million and received proceeds from issuance of common stock and other of $28.8 million.

In 2009 we had net payments on our credit facility of $195 million and $18 million of financing costs related to a new three-year senior secured revolving credit facility. Our dividend payments in 2009 were $20.2 million and we received proceeds from issuance of common stock and other of $3.4 million.

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 made dividend payments of $20 million and used $105.6 million of the borrowings under our credit facility to repurchase a portion of our convertible notes.

Reconciliation of Cash Flow from Operations

	For the Year Ended December 31,	
	2010	**2009**
	(in thousands)	
Net cash provided by operating activities	$ 1,130,432	$ 675,177
Change in operating assets and liabilities	57,699	(16,696)
Cash flow from operations	$ 1,188,131	$ 658,481

Management believes that the non-GAAP measure of cash flow from operations is useful information for investors because it is used internally and is accepted by the investment community as a means of measuring the company's ability to fund its capital program. It is also used by professional research analysts in providing investment recommendations pertaining to companies in the oil and gas exploration and production industry.

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Capital Expenditures

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

	For Years Ended December 31,		
	2010	**2009**	**2008**
Acquisitions:			
Proved	$ 15,220	$ 13,530	$ 6,618
Unproved	24,552	(9,915)*	175,777
	39,772	3,615	182,395
Exploration and development:			
Land & seismic	128,283	48,466	157,403
Exploration	103,671	45,603	245,538
Development	766,980	430,357	1,035,442
	998,934	524,426	1,438,383
Property sales	(28,235)	(109,408)	(38,093)
	$ 1,010,471	$ 418,633	$ 1,582,685

*

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

Capital expenditures in the table above are presented on an accrual basis. Additions to property and equipment in the Consolidated Statements of Cash Flows in this report reflect capital expenditures on a cash basis, when payments are made.

Our exploration and development expenditures increased 90% in 2010 compared to 2009. The lower expenditures in 2009 compared to both 2010 and 2008 resulted from a planned decrease in our exploration and development activity in response to significantly lower commodity prices in 2009 and our continued efforts to operate within our cash flow provided by operating activities.

During 2010 we drilled and completed 219 gross (129 net) wells, versus 110 gross (67 net) wells in 2009. During 2008 we drilled and completed 450 gross (277 net) wells. At year-end 2010 we had 23 operated rigs running, compared to 14 at the end of 2009 and 21 at the end of 2008.

Our planned exploration and development program for 2011 is expected to be principally funded from cash flow. Based on current market prices and services costs, our 2011 capital expenditures may range from $1.2 to $1.4 billion. Although our capital budget is set at a level that we believe corresponds with our anticipated 2011 cash flows, the timing of capital expenditures and the receipt of cash flows do not necessarily match. For example, our planned capital expenditures are front-end loaded and we may outspend cash flows for a period of time. Therefore, we may borrow and repay funds under our credit arrangement throughout the year. Should we start to see a significant change in commodity prices from our current forecasts, we have the operational flexibility to increase or decrease our capital expenditures for changes in our expected cash flows from operations.

During 2010 we had property acquisitions of $39.8 million, primarily for additional interests in our western Oklahoma, Cana-Woodford shale play. Of this total amount, $15.2 million was for proved properties. The remainder was for undeveloped acreage. In 2010 we also had land and seismic purchases of $128.3 million, of which 62% was in the Permian Basin. We made no significant property acquisitions in 2009. In 2008, 99% of our $182.4 million of acquisitions were for producing properties and exploratory nonproducing leases in our western Oklahoma, Cana-Woodford shale play. We intend to continue to actively evaluate acquisitions and dispositions relative to our property holdings, particularly in our core areas of operation.

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. The total cost of the project will approximate $354 million. Pursuant to the terms of our operating agreement with our partner in this project, we are reimbursed by them for 42.5% of the costs. Through December 31, 2010 our cumulative share of the investment in this project is approximately $110.5 million, of which $86 million is included in our fixed assets. We expect to initiate gas sales from this project in 2011.

Various interests in oil and gas properties were sold during 2010 for $28.2 million, most of which were our non-core Mississippi assets. During 2009 we sold various interests in non-core oil and gas properties for $109.4 million. Approximately 72% of the 2009 sales were our Westbrook field interests in our Permian Basin Region. In 2008 our property sales of $38.1 million were for our Word field holdings in our Gulf Coast Region.

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 2010 exploration and development drilling program is discussed in more detail in *Exploration and Development Activity Overview* under Item 1 of this report.

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 realized commodity prices. 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 2010 our total assets increased by $913.7 million to $4.4 billion, up from $3.4 billion at December 31, 2009. Our current assets contributed $154.5 million to the total increase. The increase in current assets resulted from increases in our cash and cash equivalents, increases in accounts receivable and increases in certain other current assets. These increases were partially offset by decreases in our oil and gas well equipment and supplies and in deferred income taxes. In addition, our net oil and gas assets increased during 2010 by $737.4 million and our fixed assets increased by $29 million.

Our total liabilities at the end of 2010 had increased by $342 million to $1.7 billion, up from $1.4 billion at year-end 2009. Year over year current liabilities increased by $123.6 million, primarily as a result of increases in operations related accounts payable. Long-term deferred income taxes increased during 2010 by $270.1 million and long-term debt outstanding decreased by $42.8 million. At December 31, 2010, stockholders' equity totaled $2.6 billion, up from $2.0 billion at December 31, 2009. The increase is primarily the result of our 2010 net income.

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. The dividend was increased to $0.06 per share in December 2007 and to $0.08 per share in February 2010.

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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 2010 or since the quarter ended September 30, 2007. In 2010 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, our realized commodity prices and our production operating activities. 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, 2010, we had positive working capital of $49.5 million, up $31 million from year-end 2009. Working capital increased primarily because of the following:

- Cash and cash equivalents increased by $111.6 million primarily due to increases in commodity prices and production volumes.
- Our operations related accounts receivable increased by $61.9 million.
- Our prepaid assets increased by $30 million
- Income tax receivable increased by $21.2 million.
- The aggregate fair value of our derivative instruments increased by $8.8 million.

These working capital increases were partially offset by:

- Accrued liabilities related to our drilling activity increased by $69.6 million.
- Oil and gas well equipment and supplies decreased by $63.3 million.
- Our operations related accounts payable and accrued liabilities increased by $58.2 million.
- Our deferred tax asset decreased by $11.5 million.

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

Financing

Debt at December 31, 2010 and 2009 consisted of the following (in thousands):

	2010	**2009**

Bank debt	$	$ 25,000
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023		17,793
Total long-term debt	$ 350,000	$ 392,793

Bank Debt

We have a three-year senior secured revolving credit facility ("credit facility"). The credit facility provides for bank commitments of $800 million, with a borrowing base of $1 billion. The credit facility is

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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.

At December 31, 2010, there were no outstanding borrowings under the credit facility. We had letters of credit outstanding of $7.5 million leaving an unused borrowing availability of $792.5 million.

During 2010 we only had bank borrowings outstanding in the first quarter of the year. This resulted in average daily bank debt outstanding of $4.5 million for 2010. Our maximum amount of bank borrowings outstanding during 2010 was $69 million in mid January. During 2009 our average daily bank debt outstanding was $269.6 million with a maximum amount outstanding of $410 million in mid May. At the end of 2009 our bank debt outstanding was $25 million. The significant decrease in utilization of our credit facility during 2010 is a result of improved realized commodity prices during the year.

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

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 borrowing base of $1 billion and bank commitments of $800 million were reaffirmed in October 2010.

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 agreement 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, 2010, we were in compliance with all of the financial and non-financial covenants.

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.

	Percentage
2012	103.6%
2013	102.4%
2014	101.2%
2015 and thereafter	100.0%

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At any time prior to May 1, 2012, we may 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

On July 1, 2010, all remaining holders of our floating rate convertible notes elected to convert their notes for cash and shares. In July 2010 the holders received $20.5 million (principal of $19.5 million and $1.0 million for fractional shares) and 408,450 shares of common stock. We recorded a gain of $3.8 million on the settlement of the notes.

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 notes with borrowings under our credit facility. We recorded a loss of $10.1 million on the settlement of the notes.

The notes were set to mature on December 15, 2023. The notes were senior unsecured obligations and the interest was at three month LIBOR, reset quarterly.

Pursuant to FASB guidance, the debt and equity components of the instruments were accounted for separately. The value assigned to the debt component was 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 was recorded at a discount and was 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, 2010, 2009, and 2008 was 0.7%, 2.0%, and 4.4%, respectively.

Contractual Obligations and Material Commitments

At December 31, 2010, 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)		
Debt(1)	$ 350,000	$	$	$	$ 350,000
Fixed-Rate interest payments(1)	162,094	24,938	49,875	49,875	37,406
Operating leases	15,537	5,052	8,185	2,300	
Drilling commitments(2)	209,379	195,646	13,733		
Gas processing facility(3)	79,282	54,586	24,696		
Derivatives	9,587	9,587			
Asset retirement obligation	138,769	29,276	(4)	(4)	(4)
Other liabilities(5)	48,780	12,641	25,283	33	10,823

(1) See item 7A: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) We have drilling commitments of approximately $179.9 million consisting of obligations to complete drilling wells in progress at December 31, 2010. We also have minimum expenditure commitments of $29.4 million to secure the use of drilling rigs. Subsequent to year-end we entered into a minimum expenditure commitment of $50.4 million to secure certain dedicated services.

(3) 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, 2010, we had

commitments of $103.1 million relating to construction of the gas processing plant of which $79.3 million is subject to construction contracts. The total cost of the project will approximate $354 million. Pursuant to the terms of our operating agreement with our partner 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.

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

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

At December 31, 2010, we had firm sales contracts to deliver approximately 7 Bcf of natural gas over the next ten months. If this gas is not delivered, our financial commitment would be approximately $29 million. This commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our reserves and current production levels.

In connection with a gas gathering and processing agreement, we have commitments to deliver a minimum of 30.3 Bcf of gas over the next four years. Certain wells whose production is counted toward that commitment also have individual commitments for gas deliveries. If no gas was delivered, the maximum amount that would be payable under these commitments would be approximately $25.4 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements. We do not expect to make significant payments relative to these commitments.

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 $1.9 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, development and other capital expenditures.

2011 Outlook

We expect our 2011 E&D capital expenditures to be principally funded from cash flow. Based on current market prices and service costs, we expect that 2011 E&D expenditures may range from $1.2 to $1.4 billion. At year-end 2010 we have a large inventory of drilling opportunities and limited lease expirations. We anticipate approximately 55% of the capital investment to be directed toward the Permian Basin, 38% to the Mid-Continent and 7% to the Gulf Coast and other. Our future growth will continue to depend upon our ability to economically add reserves in excess of production.

As has been our historical practice, we regularly review our capital expenditures throughout the year and will adjust our investments based on changes in commodity prices, service cost and drilling success. Operationally we have the flexibility to adjust our capital expenditures based upon market conditions.

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.

Production for 2011 is projected to be in the range of 615 to 645 MMcfe per day, or a 3-8% increase over 2010. 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 2010, our realized prices averaged $4.92 per Mcf of gas, $76.76 per barrel of oil, and $34.91 per barrel of NGL. Commodity prices can be very volatile and the possibility of realized 2011 prices varying from prices in 2010 is high.

Certain expenses for 2011 on a per Mcfe basis are currently estimated as follows:

	2011
Production expense	$0.95 - $1.15
Transportation expense	0.22 - 0.27
DD&A and asset retirement obligation	1.65 - 1.80
General and administrative	0.22 - 0.28
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.

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% of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, 50% are related to a project in Wyoming and 48% 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% of the discounted future net cash flows before income taxes.

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 about production history, well performance and production costs.

Net revisions during 2010 added 148.4 Bcfe, which included 44.8 Bcfe driven by higher commodity prices. The rest of the net revisions relate primarily to increases in our NGL volumes. The determination of whether to record and separately disclose NGL volumes is based on where title transfer occurs during processing of the well stream. New gas processing contracts and certain contractual amendments resulted in title of NGL volumes transferring to the Company. In addition, increased gas volumes with high Btu content have contributed to higher estimated NGL reserves.

	Years Ended December 31,					
	2010		2009		2008	
	Bcfe Change	Percent of total Reserves	Bcfe Change	Percent of total Reserves	Bcfe Change	Percent of total Reserves
Revisions resulting from price changes	44.8	2.92%	(30.8)	(2.30)%	(145.2)	(9.86)%
Other changes in estimates	103.6	6.75%	104.7	7.82%	(11.6)	(0.79)%
Total	148.4	9.67%	73.9	5.52%	(156.8)	(10.65)%

Non-price related revisions added 196.7 Bcfe over the three-year period 2008-2010. Over the same period we have seen a 131.2 Bcfe decrease resulting from lower prices. See Note 17, Unaudited Supplemental Oil and Gas Disclosures in this report 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.

Companies that follow the full cost accounting method are required to make quarterly "ceiling test" calculations. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects. We currently do not have any unproven properties that are being amortized. For year-end 2009, new SEC rules were implemented for future net revenues which require revenue calculations to be based on the unweighted average first-day-of-the-month prices for the prior twelve months adjusted for designated cash flow hedges. In periods prior to 2009 we used prices in effect at year-end. Changes in proved reserve estimates (whether based upon quantity revisions or commodity 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.

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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 in 2008. As a result of further declines in natural gas 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. Our quarterly and annual ceiling test are 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, 2010 would not have resulted in a ceiling test impairment. Decreases in commodity prices can also impact our goodwill impairment analyses.

Goodwill

At December 31, 2010, 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, 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, 2010, the market price per share of our common stock was greater than the book value by $58 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%. 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, 2010 (adjusted for estimated delivery point price differentials). As of December 31, 2010, 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

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matters. Only $6.9 million of the judgment pertained to damages, with the remainder being disgorgement of H&P's estimated potential compounded profit since 1989 resulting from the noted damages. 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 and 2010, we have accrued an additional $9.4 million and $8.9 million, respectively. 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. 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 2010, we revised our existing estimated asset retirement obligation by $8.9 million, or approximately 6% of the asset retirement obligation at December 31, 2010, due to changes in the various related attributes. Over the past three years, revisions to the estimated asset retirement obligation averaged approximately 10.6%. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to 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

There have been no significant accounting standards applicable to Cimarex issued during 2010.

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.

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The following table details the contracts we have in place as of December 31, 2010:

Natural Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Ceiling	Swap	Fair Value (000's)
Jan 11 - Dec 11	Swap	20,000 MMBtu	PEPL			$ 5.05	$ 5,731

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Ceiling	Fair Value (000's)
Jan 11 - Dec 11	Collar	12,000 Bbls	WTI	$ 65.00	$ 105.44	$ (9,587)

(1) PEPL refers to Panhandle Eastern Pipe Line Company price 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 2011 gas 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 $0.7 million. For the 2011 oil contracts listed above, a hypothetical $1.00 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 $4.4 million.

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. 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, 2010, our debt was our senior unsecured notes that bear interest at a fixed rate of 7.125% and will mature on May 1, 2017.

At December 31, 2010, we consider our interest rate exposure to be minimal because all of our long-term debt obligations were at fixed rates. This assessment 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.

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.

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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, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, 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 25, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver, Colorado

February 25, 2011

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CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share information)

	December 31, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 114,126	$ 2,544
Restricted cash	699	593
Accounts receivable:		
Trade, net of allowance	60,298	41,252
Oil and gas sales, net of allowance	218,543	176,551
Gas gathering, processing, and marketing, net of allowance	7,127	6,292
Other	25,000	3,801
Oil and gas well equipment and supplies	81,871	145,153
Deferred income taxes	4,293	15,837
Derivative instruments	5,731	1,238
Prepaid Expenses	33,886	3,907
Other current assets	10,193	10,090
Total current assets	561,767	407,258
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	8,421,768	7,549,861
Unproved properties and properties under development, not being amortized	547,609	399,724
	8,969,377	7,949,585
Less accumulated depreciation, depletion and amortization	(6,047,019)	(5,764,669)
Net oil and gas properties	2,922,358	2,184,916
Fixed assets, less accumulated depreciation of $97,066 and $88,544	156,579	127,237
Goodwill	691,432	691,432
Other assets, net	26,111	33,694
	$ 4,358,247	$ 3,444,537
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 34,120	$ 18,309
Gas gathering, processing, and marketing	13,122	11,905
Accrued liabilities:		
Exploration and development	122,422	52,781
Taxes other than income	35,489	27,956
Other	163,078	155,078
Derivative instruments	9,587	13,902
Revenue payable	134,495	108,832
Total current liabilities	512,313	388,763
Long-term debt		

	350,000	392,793
Deferred income taxes	619,040	348,897
Asset retirement obligation	109,493	129,785
Other liabilities	157,569	146,193
Total liabilities	1,748,415	1,406,431
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, 85,234,721 and 83,541,995 shares issued, respectively	852	835
Paid-in capital	1,883,065	1,859,255
Retained earnings	725,651	178,035
Accumulated other comprehensive (loss) income	264	(19)
	2,609,832	2,038,106
	$ 4,358,247	$ 3,444,537

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

	For the Years Ended December 31, 2010	2009	2008
Revenues:			
Gas sales	$ $653,793	$ 485,448	$ 1,074,705
Oil sales	755,618	468,833	797,382
NGL Sales	149,151	8,162	8,804
Gas gathering, processing and other	54,662	46,763	87,757
Gas marketing, net of related costs of $99,713, $68,719 and $141,668 respectively	459	588	1,699
	$ 1,613,683	1,009,794	1,970,347
Costs and expenses:			
Impairment of oil and gas properties		791,137	2,242,921
Depreciation, depletion and amortization	304,222	265,699	547,404
Asset retirement obligation	7,322	12,313	8,796
Production	194,015	178,215	218,736
Transportation	49,968	33,758	38,107
Gas gathering and processing	22,162	20,560	43,838
Taxes other than income	121,781	75,634	130,490
General and administrative	48,620	41,724	44,500
Stock compensation, net	12,353	9,254	10,090
(Gain) loss on derivative instruments, net	(62,696)	13,059	
Other operating, net	4,575	24,263	126,433
	702,322	1,465,616	3,411,315
Operating income (loss)	911,361	(455,822)	(1,440,968)
Other (income) and expense:			
Interest expense	36,613	39,777	33,079
Capitalized interest	(29,215)	(23,408)	(22,108)
(Gain) loss on early extinquishment of debt	(3,776)		10,058
Other, net	(5,992)	16,290	(10,348)
Income (loss) before income tax	913,731	(488,481)	(1,451,649)
Income tax expense (benefit)	338,949	(176,538)	(536,404)
Net income (loss)	$ 574,782	$ (311,943)	$ (915,245)
Earnings (loss) per share to common shareholders:			
Basic			
Distributed	$ 0.32	$ 0.24	$ 0.24
Undistributed	6.42	(4.06)	(11.46)
	$ 6.74	$ (3.82)	$ (11.22)

Diluted			
Distributed	$ 0.32	$ 0.24	$ 0.24
Undistributed	6.38	(4.06)	(11.46)
	$ 6.70	$ (3.82)	$ (11.22)

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income (loss)	$ 574,782	$ (311,943)	$ (915,245)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairments and other valuation losses		806,039	2,259,687
Depreciation, depletion and amortization	304,222	265,699	547,404
Asset retirement obligation	7,322	12,313	8,796
Deferred income taxes	292,612	(164,760)	(602,593)
Stock compensation, net	12,353	9,254	10,090
Derivative instruments, net	(10,598)	14,453	
Gain on liquidation of equity investees			(39)
Changes in non-current assets and liabilities	12,772	8,948	119,562
Other, net	(5,334)	18,478	15,557
Changes in operating assets and liabilities			
(Increase) decrease in receivables, net	(83,386)	29,881	56,245
(Increase) decrease in oil and gas well equipment and supplies and other current assets	34,250	49,894	(155,222)
Increase (decrease) in accounts payable and other current liabilities	(8,563)	(63,079)	23,246
Net cash provided by operating activities	1,130,432	675,177	1,367,488
Cash flows from investing activities:			
Oil and gas expenditures	(959,751)	(535,308)	(1,594,775)
Sales of oil and gas and other assets	34,075	119,735	39,096
Distributions received from equity investees			39
Sales of short-term investments		3,328	10,679
Other capital expenditures	(51,882)	(31,849)	(51,757)
Net cash used by investing activities	(977,558)	(444,094)	(1,596,718)
Cash flows from financing activities:			
Net Increase (decrease) in bank debt	(25,000)	(195,000)	220,000
Decrease in other long-term debt	(19,450)		(105,550)
Financing costs incurred	(101)	(18,001)	(158)
Dividends paid	(25,499)	(20,172)	(20,040)
Issuance of common stock and other	28,758	3,421	13,141
Net cash provided by (used in) financing activities	(41,292)	(229,752)	107,393
Net change in cash and cash equivalents	111,582	1,331	(121,837)
Cash and cash equivalents at beginning of period	2,544	1,213	123,050
Cash and cash equivalents at end of period	$ 114,126	$ 2,544	$ 1,213

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

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CIMAREX ENERGY CO.

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

(In thousands)

	Common Stock				Accumulated Other Comprehensive		Total
	Shares	Amount	Paid-in Capital	Retained Earnings	Income (loss)	Treasury Stock	Stockholders' Equity
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				
Exercise of stock options	414	4	6,425				6,429
Vesting of restricted stock units	45						
Stock-based compensation			17,222				17,222
Stock-based compensation tax benefit			6,712				6,712
Comprehensive (loss):							
Net (loss)				(915,245)			(915,245)
Net change from hedging activity					(7,652)		(7,652)
Unrealized change in fair value of investments, 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				
Exercise of stock options	134	1	2,212				2,213
Vesting of restricted stock units	5						
Stock-based compensation			16,778				16,778
Stock-based compensation tax benefit			1,208				1,208
Comprehensive (loss):							
Net (loss)				(311,943)			(311,943)
Unrealized change in fair value of investments, 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
Dividends				(27,166)			(27,166)
Stock issued due to conversion of convertible debt (see Note 7)	408	4	30,126				30,130
Issuance of restricted stock awards	638	6	(6)				
Common stock reacquired and retired	(428)	(4)	(32,200)				(32,204)
Restricted stock forfeited and retired	(76)	(1)	1				
Exercise of stock options	596	6	17,985				17,991
Vesting of restricted stock units	555	6	(6)				
Stock-based compensation			21,688				21,688
Stock-based compensation tax benefit			22,767				22,767
Equity attributable to Floating rate convertible notes			(36,545)				(36,545)

Comprehensive income:							
Net income				574,782			574,782
Unrealized change in fair value of investments, net of tax					283		283
Total comprehensive income							575,065
Balance, December 31, 2010	85,235	$ 852	$ 1,883,065	$ 725,651	$ 264	$	$ 2,609,832

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 2010 financial statement presentation.

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 79% of our total proved reserves and approximately 85% of our 2010 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.

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

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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.

Companies that follow the full cost accounting method are required to make quarterly "ceiling test" calculations. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects. We currently do not have any unproven properties that are being amortized. For year-end 2009, new Securities and Exchange Commission ("SEC") rules were implemented for future net revenues which require revenue calculations to be based on the unweighted average first-day-of-the-month prices for the prior twelve months adjusted for designated cash flow hedges. In periods prior to 2009 we used prices in effect at period end. Changes in proved reserve estimates (whether based upon quantity revisions or commodity 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 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 in 2008. As a result of further declines in gas 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. Our quarterly and annual ceiling tests are 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, 2010 would not have resulted in a ceiling test impairment. 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, including future development costs and asset retirement obligations, are amortized over total estimated proved reserves. The capitalized costs of unproved properties, including wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized resulting from the determination of proved reserves or impairments. 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, 2010, 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

Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

(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, 2010, the market price per share of our common stock was greater than the book value by $58 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%. 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, 2010 (adjusted for estimated delivery point price differentials). As of December 31, 2010, 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, Gas and NGL Sales

Revenues from oil, gas and NGL sales are based on the sales method, with revenue recognized on actual volumes sold to purchasers. There is a ready market for our production, with sales occurring soon after production. The determination to record and separately disclose NGL volumes is based on the location at which both title contractually transfers from Cimarex to a buyer and the associated volumes can be physically quantified. For those NGL volumes that we have recorded and disclosed separately, contractual title of the volumes has passed from Cimarex to a buyer at a point where the NGL volumes have been physically separated from the production stream. Should title contractually transfer before NGL volumes can be physically separated and quantified (typically at the wellhead), we do not report separate NGL volumes, and the value of the NGLs are included in the reported value of the disclosed gas volumes.

Marketing Sales

We market and sell natural gas for working interest owners 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.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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. 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, 2010 and 2009 was $4.0 million and $4.3 million, respectively. At December 31, 2010 and 2009, 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 our reserve estimates 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.

At year-end, 23% of our total proved reserves are categorized as proved undeveloped. Of these proved undeveloped reserves, a significant percentage is 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.

We use the units-of-production method to amortize the cost of our oil and gas properties. Changes in our estimate of 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.

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

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 2008 were all related to natural gas and were designated 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. At December 31, 2008, there were no remaining contracts outstanding.

During 2009 and 2010, we entered into additional derivative contracts which cover a portion of our anticipated production through December 2011. We did not choose to apply hedge accounting treatment to any of the contracts we have entered into during these periods. 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 Financial Accounting Standards Board ("FASB"). At December 31, 2010 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. See Note 15 for additional information regarding our contingencies.

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.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Accrued liabilities, other

Included in Accrued liabilities, other at December 31, 2010 and 2009, respectively, are liabilities of approximately $31.3 million and $27.7 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Also included in accrued liabilities, other at December 31, 2010 and 2009, respectively, are accrued payroll related general and administrative of $44.8 million and $33.8 million, and the current portion of the Asset retirement obligation of $29.3 million and $19.5 million.

Stock-based Compensation

We recognize compensation related to all stock-based awards, including stock options, in the financial statements based on their estimated grant-date fair value. We grant various types of stock-based awards including stock options, restricted stock (includes service-based vesting and market condition-based vesting) and restricted stock units. The fair value of stock option awards is determined using the Black-Scholes option pricing model. Service-based restricted stock and units are valued using the market price of our common stock on the grant date. 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 to estimate the percentage of awards that will vest at the end of the vesting period. Compensation cost is recognized ratably over the applicable vesting period. See Note 9 for additional information regarding our stock-based compensation.

Earnings per Share

We calculate earnings (loss) per share based on FASB guidance which holds that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are "participating securities" 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. Under this guidance, our unvested share based payment awards, consisting of restricted stock and restricted stock units, qualify as participating securities.

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 GAAP

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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, 2008	$ 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)
2010 activity		283	283
Balance at December 31, 2010	$	$ 264	$ 264

(1) Net of tax

Segment Information

Cimarex has one reportable segment (exploration and production).

Recently Issued Accounting Standards

There have been no significant accounting standards applicable to Cimarex issued during 2010.

Subsequent Events

The accompanying financial disclosures include an evaluation of subsequent events through the date of this filing.

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.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

At December 31, 2010, 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 Swap	Fair Value (000's)
Jan 11 - Dec 11	Swap	20,000 MMBtu	PEPL	$ 5.05	$ 5,731

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (000's)
Jan 11 - Dec 11	Collar	12,000 Bbls	WTI	$ 65.00	$ 105.44	$ (9,587)

(1) PEPL refers to Panhandle Eastern Pipe Line Company price 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.

Oil contracts that expire in 2011 represent approximately 40-45% of our anticipated oil production for 2011. Our gas swap contracts presently in place represent approximately 5-6% of expected 2011 gas sales volumes.

For 2011, management has been authorized to hedge up to 50% of our anticipated equivalent oil and gas production. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our current hedging positions.

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. 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.

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 published forward commodity price curves for the underlying commodity as of the date of the estimate. For collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract terms. The fair values of our derivative instruments in an asset position include a measure of counterparty credit risk, and the fair values of instruments in a liability position include a measure of our own nonperformance risk. 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

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

ultimate settlement price. The following tables present the estimated fair values of our derivative assets and liabilities as of December 31, 2010 and 2009:

December 31, 2010:	Balance Sheet Location		Asset	Liability
			(In thousands)	
Natural gas contracts	Current assets	Derivative instruments	$ 5,731	$
Oil contracts	Current liabilities	Derivative instruments		9,587
			$ 5,731	$ 9,587

December 31, 2009:	Balance Sheet Location		Asset	Liability
			(In thousands)	
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
			$ 1,238	$ 13,902

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 natural gas 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.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. DERIVATIVE INSTRUMENTS/HEDGING (Continued)

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

	2010	2009	2008
Derivatives not designated as hedging instruments:			
Settlements gains (losses):			
Natural gas contracts	$ 53,985	$ 1,394	$
Oil contracts	(1,887)		
Total settlements gains (losses)	52,098	1,394	
Unrealized gains (losses) on fair value change:			
Natural gas contracts	8,802	(3,070)	
Oil contracts	1,796	(11,383)	
Total net unrealized gains (losses) on fair value change	10,598	(14,453)	
Gain (loss) on derivative instruments, net	$ 62,696	$ (13,059)	$
Derivatives designated as cash flow hedges:			
Natural gas contracts gains:			
Cash receipts included in gas sales	$	$	$ 11,272
Unrealized gains on fair value change included in other comprehensive income (loss)	$	$	$

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 mitigated our exposure to any single counterparty by contracting with a number of 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.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FAIR VALUE MEASUREMENTS (Continued)

The following tables provide fair value measurement information for certain assets and liabilities as of December 31, 2010 and 2009:

December 31, 2010:	**Carrying Amount**	**Fair Value**
	(In thousands)	
Financial Assets (Liabilities):		
7.125% Notes due 2017	$ (350,000)	$ (358,750)
Derivative instruments assets	$ 5,731	$ 5,731
Derivative instruments liabilities	$ (9,587)	$ (9,587)

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

Assessing the significance of a particular input to the fair value measurement requires judgment, including the consideration of 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.

Debt

Bank Debt

We had no bank debt at December 31, 2010. The fair value of our bank debt at December 31, 2009 was estimated to approximate the carrying amount because the floating rate interest paid on such debt was set for periods of three months or less.

Other Debt

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

In July 2010 the convertible notes were tendered and paid. Please see Note 7 for further information on the payout of our convertible notes.

There was not an observable market for our convertible notes. At December 31, 2009, the closing price of our common stock (as defined by the indenture) 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 fair value of the face amount of the notes was estimated to approximate the face value of the notes because the notes bear interest at LIBOR, and reset quarterly. The fair value of the conversion feature was calculated using the conversion formula for the notes, based on the closing price per share for our common stock at December 31, 2009.

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Cimarex Energy Co.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. FAIR VALUE MEASUREMENTS (Continued)

Derivative Instruments

The fair values of our derivative instruments at December 31, 2010 were 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. Please see Note 4 for further information on the fair values of our derivative instruments.

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, 2010, the allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $6.3 million, $0.5 million, and zero, respectively. 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.

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.

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, 2010 and 2009 (in thousands):

	2010	2009
Asset retirement obligation at January 1,	$ 149,310	$ 139,948
Liabilities incurred	4,555	3,730
Liability settlements and disposals	(31,514)	(15,598)
Accretion expense	7,535	7,819