CIMAREX ENERGY CO
Form 10-Q
August 04, 2010
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **Quarterly Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934**

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

For the Quarterly Period ended June 30, 2010

Commission File No. 001-31446

CIMAREX ENERGY CO.

1700 Lincoln Street, Suite 1800

Denver, Colorado 80203-4518

(303) 295-3995

Incorporated in the State of Delaware	**Employer Identification No. 45-0466694**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark 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 x No 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 x	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 Exchange Act). Yes o No x.

The number of shares of Cimarex Energy Co. common stock outstanding as of June 30, 2010 was 84,094,582.

Table of Contents

CIMAREX ENERGY CO.

Table of Contents

		Page
PART I		
Item 1 Financial Statements		
	Consolidated balance sheets (unaudited) as of June 30, 2010 and December 31, 2009	4
	Consolidated statements of operations (unaudited) for the three and six months ended June 30, 2010 and 2009	5
	Consolidated statements of cash flows (unaudited) for the six months ended June 30, 2010 and 2009	6
	Notes to consolidated financial statements (unaudited)	7
Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations		24
Item 3 Qualitative and Quantitative Disclosures about Market Risk		41
Item 4 Controls and Procedures		43
PART II		
Item 6 Exhibits		44
Signatures		45

Table of Contents

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

MBbls Thousand barrels

Mcf Thousand cubic feet (of natural gas)

Mcfe Thousand cubic feet equivalent

MMBbls Million barrels

MMBtu Million British Thermal Units

MMcf Million cubic feet

MMcf/d Million cubic feet per day

MMcfe Million cubic feet equivalent

MMcfe/d Million cubic feet equivalent per day

Net Acres Gross acreage multiplied by working interest percentage

Net Production Gross production multiplied by net revenue interest

NGL Natural gas liquids

Tcf Trillion cubic feet

Tcfe Trillion cubic feet equivalent

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

CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS

Throughout this Form 10-Q, 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 and Exchange Act of 1934. These forward-looking statements include, among others, statements concerning our outlook with regard to timing and amount of future production of oil and gas, price realizations, amounts, nature and timing of capital expenditures for exploration and development, plans for funding operations and capital expenditures, drilling of wells, operating costs and other expenses, marketing of oil and gas and other statements of expectations, beliefs, future plans and strategies, anticipated events or trends, and similar expressions concerning matters that are not historical facts. The forward-looking statements in this report are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in or implied by the statements.

These risks and uncertainties include, but are not limited to, fluctuations in the price we receive for our oil and gas production, reductions in the quantity of oil and gas sold due to decreased industry-wide demand and/or curtailments in production from specific properties due to mechanical, marketing or other problems, operating and capital expenditures that are either significantly higher or lower than anticipated because the actual cost of identified projects varied from original estimates and/or from the number of exploration and development opportunities being greater or fewer than currently anticipated, and increased financing costs due to a significant increase in interest rates. In addition, exploration and development opportunities that we pursue may not result in productive oil and gas properties. There are also numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and the timing of development expenditures. These and other risks and uncertainties affecting us are discussed in greater detail in this report and in our other filings with the Securities and Exchange Commission.

Table of Contents

PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Consolidated Balance Sheets

	June 30, 2010 (Unaudited)	December 31, 2009
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 142,057	$ 2,544
Restricted cash	659	593
Receivables, net	217,822	227,896
Oil and gas well equipment and supplies	111,143	145,153
Deferred income taxes		15,837
Derivative instruments	23,570	1,238
Other current assets	32,308	13,997
Total current assets	527,559	407,258
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	7,909,086	7,549,861
Unproved properties and properties under development, not being amortized	475,899	399,724
	8,384,985	7,949,585
Less accumulated depreciation, depletion and amortization	(5,896,323)	(5,764,669)
Net oil and gas properties	2,488,662	2,184,916
Fixed assets, net	130,722	127,237
Goodwill	691,432	691,432
Other assets, net	32,258	33,694
	$ 3,870,633	$ 3,444,537
Liabilities and Stockholders Equity		
Current liabilities:		
Current maturities of long-term debt	$ 17,871	$
Accounts payable	38,437	30,214
Accrued liabilities	251,630	235,815
Derivative instruments	109	13,902
Revenue payable	113,430	108,832
Total current liabilities	421,477	388,763
Long-term debt	350,000	392,793
Deferred income taxes	455,987	348,897
Other liabilities	275,517	275,978
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, 84,094,582 and 83,541,995 shares issued, respectively	841	835
Paid-in capital	1,873,414	1,859,255
Retained earnings	493,565	178,035

Accumulated other comprehensive loss		(168)		(19)
		2,367,652		2,038,106
	$	3,870,633	$	3,444,537

See accompanying notes to consolidated financial statements.

Table of Contents

CIMAREX ENERGY CO.

Consolidated Statements of Operations

(Unaudited)

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
	(In thousands, except per share data)			
Revenues:				
Gas sales	$ 151,375	$ 100,539	$ 377,012	$ 217,163
Oil sales	180,664	110,850	372,224	190,187
NGL sales	32,851	1,979	48,060	3,247
Gas gathering, processing and other	13,602	9,363	29,452	20,433
Gas marketing, net	9	(46)	323	834
	378,501	222,685	827,071	431,864
Costs and expenses:				
Impairment of oil and gas properties				791,137
Depreciation, depletion and amortization	73,146	56,885	142,856	146,551
Asset retirement obligation	1,641	2,096	4,285	4,641
Production	45,356	46,031	87,339	96,445
Transportation	10,825	7,764	21,992	16,473
Gas gathering and processing	6,100	4,411	12,605	9,517
Taxes other than income	28,410	15,252	60,768	30,797
General and administrative	11,817	9,519	24,862	17,281
Stock compensation, net	2,993	2,097	5,771	4,354
(Gain) loss on derivative instruments, net	(3,289)	358	(55,886)	256
Other operating, net	1,876	6,091	30	16,183
	178,875	150,504	304,622	1,133,635
Operating income (loss)	199,626	72,181	522,449	(701,771)
Other (income) and expense:				
Interest expense	9,101	11,254	18,563	19,521
Capitalized interest	(7,285)	(5,422)	(14,709)	(10,935)
Other, net	1,851	5,535	(79)	7,890
Income (loss) before income tax	195,959	60,814	518,674	(718,247)
Income tax expense (benefit)	71,339	22,007	189,693	(262,954)
Net income (loss)	$ 124,620	$ 38,807	$ 328,981	$ (455,293)
Earnings (loss) per share to common stockholders:				
Basic				
Distributed	$ 0.08	$ 0.06	$ 0.16	$ 0.12
Undistributed	1.39	0.40	3.72	(5.70)
	$ 1.47	$ 0.46	$ 3.88	$ (5.58)
Diluted				
Distributed	$ 0.08	$ 0.06	$ 0.16	$ 0.12
Undistributed	1.38	0.40	3.68	(5.70)
	$ 1.46	$ 0.46	$ 3.84	$ (5.58)

See accompanying notes to consolidated financial statements.

Table of Contents

CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Six Months Ended June 30, 2010	2009
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ 328,981	$ (455,293)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairments and other valuation losses		801,905
Depreciation, depletion and amortization	142,856	146,551
Asset retirement obligation	4,285	4,641
Deferred income taxes	125,303	(234,120)
Stock compensation, net	5,771	4,354
Derivative instruments, net	(38,775)	3,625
Changes in non-current assets and liabilities	5,614	5,879
Other, net	(934)	13,212
Changes in operating assets and liabilities:		
Decrease in receivables, net	10,049	76,306
(Increase) decrease in other current assets	16,587	(26,000)
Decrease in accounts payable and accrued liabilities	(27,477)	(146,714)
Net cash provided by operating activities	572,260	194,346
Cash flows from investing activities:		
Oil and gas expenditures	(426,941)	(292,742)
Sales of oil and gas and other assets	28,905	18,563
Sales of short-term investments		1,230
Other expenditures	(14,808)	(10,727)
Net cash used by investing activities	(412,844)	(283,676)
Cash flows from financing activities:		
Net increase (decrease) in bank debt	(25,000)	119,000
Financing costs incurred	(100)	(17,961)
Dividends paid	(11,835)	(10,076)
Issuance of common stock and other	17,032	114
Net cash (used in) provided by financing activities	(19,903)	91,077
Net change in cash and cash equivalents	139,513	1,747
Cash and cash equivalents at beginning of period	2,544	1,213
Cash and cash equivalents at end of period	$ 142,057	$ 2,960

See accompanying notes to consolidated financial statements.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2010

(Unaudited)

1. Basis of Presentation

The accompanying unaudited financial statements have been prepared by Cimarex Energy Co. pursuant to rules and regulations of the Securities and Exchange Commission (SEC). Accordingly, certain disclosures required by accounting principles generally accepted in the United States and normally included in annual reports on Form 10-K have been omitted. Although management believes that our disclosures in these interim financial statements are adequate, they should be read in conjunction with the financial statements, summary of significant accounting policies, and footnotes included in our 2009 Annual Report on Form 10-K.

In the opinion of management, the accompanying financial statements reflect all adjustments necessary to present fairly our financial position, results of operations, and cash flows for the periods shown. We have evaluated subsequent events after the balance sheet date of June 30, 2010, through the filing of this report.

Full Cost Accounting Method and Ceiling Limitation

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration, and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities, and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of properties, as well as other internal costs that can be directly identified with acquisition, exploration, and development activities, are also capitalized. Under the full cost method of accounting, no gain or loss is recognized upon the disposition of oil and gas properties unless such disposition would significantly alter the relationship between capitalized costs and proved reserves.

At the end of each quarter, we make a full cost ceiling limitation calculation, whereby net capitalized costs related to proved properties less associated deferred income taxes may not exceed the amount of the present value discounted at 10% of estimated future net revenues from proved reserves less estimated future production and development costs and related income tax expense. Future net revenues used in the calculation of the full cost ceiling limitation have previously been determined based on current commodity prices adjusted for designated cash flow hedges. Beginning in December 2009, new SEC rules were implemented requiring reserve calculations to be based on the unweighted average first-day-of-the-month prices for the prior twelve months. Changes in proved reserve estimates (whether based upon quantity revisions or 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. In periods prior to year-end 2009 we used prices in effect at period end.

Due to decreases in period end commodity prices at March 31, 2009, our ceiling limitation calculation resulted in excess capitalized costs of $791 million ($502 million, net of tax), for which we recorded a non-cash impairment of oil and gas properties. No further impairments have been recorded since 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 June 30, 2010 would not have resulted in a ceiling test impairment. Decreases in commodity prices can also impact our goodwill impairment analyses.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, as adjusted for future development costs and asset retirement obligations, are amortized over the total estimated proved reserves. The costs of wells in progress and certain unevaluated properties are not being amortized. On a quarterly basis, we evaluate such costs for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments, or reductions in value. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Goodwill

At June 30, 2010, we had $691.4 million of goodwill recorded in conjunction with past business combinations. Goodwill is subject to annual reviews for impairment, but we continuously monitor the economic environment throughout the year to determine if additional impairment assessments are necessary. These assessments are 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 done.

Disruptions continue in the credit markets and global economic activity which impact stock markets and commodity prices. Management must apply judgment in determining the estimated fair value of the Company for purposes of assessing goodwill impairment. As of June 30, 2010, the market price per share of our common stock was greater than the book value by $43 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 the fair value 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. Should lower prices or quantities result in the future, or higher discount rates are necessary, the carrying value of our net assets may exceed the estimated fair value, resulting in an impairment of goodwill.

Use of Estimates

We make certain estimates and assumptions to prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. Those estimates and assumptions affect the reported amounts of assets, liabilities, revenues, and expenses during the reporting period and in disclosures of commitments and contingencies. 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.

The more significant areas requiring the use of management s estimates and judgments relate to the estimation of proved oil and gas reserves, the use of these oil and gas reserves in calculating depletion, depreciation, and amortization, the use of the estimates of future net revenues in computing ceiling test limitations and estimates of future abandonment obligations used in recording asset retirement

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

obligations, and the assessment of goodwill. Estimates and judgments are also required in determining reserves for bad debt, impairments of undeveloped properties and other assets, purchase price allocation, valuation of deferred tax assets, fair value measurements and commitments and contingencies.

Accounting Changes

Certain amounts in prior years financial statements have been reclassified to conform to the 2010 financial statement presentation.

Recently Issued Accounting Standards

There have been no significant accounting standards applicable to Cimarex issued during the quarter ended June 30, 2010.

2. 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.

At June 30, 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 Floor	Ceiling	Swap	Fair Value (000 s)
Jul 10 - Dec 10	Collar	100,000 MMBtu	PEPL	$ 5.00	$ 6.62		$ 13,655
Jul 10 - Dec 10	Swap	40,000 MMBtu	PEPL			$ 5.18	$ 5,436
Jul 10 - Dec 10	Collar	20,000 MMBtu	HSC	$ 5.00	$ 6.85		$ 2,107
Jan 11 Dec 11	Swap	10,000 MMBtu	PEPL			$ 5.10	$ 401

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Ceiling	Fair Value (000 s)
Jul 10 - Dec 10	Collar	10,000 Bbls	WTI	$ 60.03	$ 92.07	$ (456)
Jul 10 - Dec 10	Put/Floor	1,000 Bbls	WTI	$ 60.00	$	$ 153
Jan 11 - Dec 11	Collar	6,000 Bbls	WTI	$ 65.00	$ 106.20	$ 3,927

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

The combined gas and oil contracts that expire in 2010 represent approximately 37% of our equivalent oil and gas production for the remainder of 2010. During the six months ended June 30, 2010, we entered into additional oil and gas contracts relative to our 2011 production, as noted in the table above. Management has been authorized to hedge up to 50% of our anticipated equivalent oil and gas production for 2011. Subsequent to June 30, 2010 we entered into additional derivative contracts relative to our 2011 oil and gas production.

Under a collar agreement, we receive the difference between the published index price and a floor price if the index price is below the floor. We pay the difference between the ceiling price and the index price only if the index price is above the contracted ceiling price. No amounts are paid or received if the

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

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

Our derivative contracts are carried at their fair value on our balance sheet. We estimate the fair value using internal risk adjusted discounted cash flow calculations. Cash flows are based on 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. Due to the volatility of commodity prices, the estimated fair values of our derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. The following tables present the estimated fair values of our derivative assets and liabilities as of June 30, 2010 and December 31, 2009.

	Balance Sheet Location		Asset		Liability
			(In thousands)		
June 30, 2010:					
Natural gas contracts	Current assets Derivative instruments	$	21,584	$	
Oil contracts	Current assets Derivative instruments		1,986		
Natural gas contracts	Noncurrent assets Other assets, net		15		
Oil contracts	Noncurrent assets Other assets, net		1,747		
Oil contracts	Current liabilities Derivative instruments				109
		$	25,332	$	109

	Balance Sheet Location		Asset		Liability
			(In thousands)		
December 31, 2009:					
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. Cash settlements of our derivative contracts are included in cash flows from operating activities in our statements of cash flows.

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

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(In thousands)			
Cash settlements gains (losses):				
Natural gas contracts	$ 17,016	$ 3,369	$ 17,998	$ 3,369
Oil contracts	(446)		(887)	
Total cash settlements gains (losses)	16,570	3,369	17,111	3,369
Unrealized gains (losses) on fair value change:				
Natural gas contracts	(25,898)	(2,415)	24,670	(2,313)
Oil contracts	12,617	(1,312)	14,105	(1,312)
Total unrealized losses on fair value change	(13,281)	(3,727)	38,775	(3,625)
Gain (loss) on derivative instruments, net	$ 3,289	$ (358)	$ 55,886	$ (256)

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

3. *Fair Value Measurements*

The Financial Accounting Standards Board (FASB) has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 inputs are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for an asset or liability.

The following tables provide fair value measurement information for certain assets and liabilities as of June 30, 2010 and December 31, 2009.

	Carrying Amount	Fair Value
	(In thousands)	
June 30, 2010:		
Financial Assets (Liabilities):		
7.125% Notes due 2017	$ (350,000)	$ (353,500)

Floating rate convertible notes due 2023	$	(17,871)	$	(50,646)
Derivative instruments - assets	$	25,332	$	25,332
Derivative instruments - liabilities	$	(109)	$	(109)

		Carrying Amount		**Fair Value**
		(In thousands)		
December 31, 2009:				
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, considering factors specific to the asset or liability. The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

Bank Debt and Notes

Debt

We had no bank debt at June 30, 2010. The fair value of our bank debt at December 31, 2009 was estimated to approximate the carrying amount because the floating rate interest rate paid on such debt was set for periods of three months or less.

Notes

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

On July 1, 2010, the convertible notes were tendered; therefore, the June 30, 2010 fair value of the convertible notes was valued using the cash and equity payout made in July 2010.

There has not been 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 attributable to the conversion feature ($28.59); 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 the London Interbank Offered Rate, 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.

Derivative Instruments (Level 2)

The fair values of our derivative instruments at June 30, 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 2 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 June 30, 2010 and December 31, 2009, the aggregate allowance for doubtful accounts for trade, oil and gas sales, and gas gathering, processing, and marketing receivables was $6.9 million.

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.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

4. Capital Stock

A summary of our common stock activity for the six months ended June 30, 2010 follows:

	Number of Shares (in thousands)		
	Issued	**Treasury**	**Outstanding**
December 31, 2009	83,542		83,542
Restricted shares issued under compensation plans, net of cancellations	257		257
Option exercises, net of cancellations	296		296
June 30, 2010	84,095		84,095

Stock-based Compensation

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

Restricted Stock and Units

During the six months ended June 30, 2010, we issued a total of 450,024 restricted shares to non-employee directors, officers, and other employees. Included in that amount are 396,000 shares issued to certain executives that are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group s stock price performance. After three years of continued service, an executive will be entitled to vest in 50% to 100% of the award. The material terms of performance goals applicable to these awards were approved by stockholders in May 2006. The other shares granted in 2010 have service-based vesting schedules of five years.

The following table presents restricted stock activity as of June 30, 2010 and changes during the year:

Outstanding as of January 1, 2010	1,727,250
Vested	(379,443)
Granted	450,024
Canceled	(55,720)
Outstanding as of June 30, 2010	1,742,111

The following table presents restricted unit activity as of June 30, 2010 and changes during the year:

Outstanding as of January 1, 2010	649,843
Converted to Stock	(2,336)
Granted	
Canceled	
Outstanding as of June 30, 2010	647,507
Vested included in outstanding	646,243

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

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

Compensation expense for service-based vesting restricted shares or units is based upon amortization of the grant-date market value of the award. The fair value of the market condition-based restricted stock awards is based on the grant-date market value of the award utilizing a Monte Carlo simulation model to estimate the percentage of awards that will vest at the end of a three-year period. Compensation expense related to the restricted stock and unit awards is recognized ratably over the applicable vesting period. Compensation expense (including capitalized amounts) for the quarters ended June 30, 2010 and 2009 was $4.4 million and $3.6 million, respectively. For the six months ended June 30, 2010 and 2009, compensation expense (including capitalized amounts) totaled $8.2 million and $5.9 million, respectively.

Unamortized compensation cost related to unvested restricted shares and units at June 30, 2010 and 2009 was $37.2 million and $33.5 million, respectively.

Stock Options

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

There were 21,500 stock options granted to employees during the six months ended June 30, 2010. There were 150,575 stock options granted to employees during the six months ended June 30, 2009.

Information about outstanding stock options is summarized below:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (000)
Outstanding as of January 1, 2010	1,573,974	$ 29.93		
Exercised	(362,629)	$ 23.54		
Granted	21,500	$ 71.49		
Canceled	(1,699)	$ 56.74		
Forfeited	(22,664)	$ 46.34		
Outstanding as of June 30, 2010	1,208,482	$ 32.24	5.5 Years	$ 48,303

Exercisable as of June 30, 2010	737,908	$ 23.15	3.8 Years	$	36,177

There were 362,629 and 5,973 stock options exercised during the six months ended June 30, 2010 and June 30, 2009, respectively. Cash received from option exercises during the six months ended June 30, 2010 and June 30, 2009 was $8.5 million and $70 thousand, respectively. The related tax benefits realized from option exercises totaled $ 5.1 million and $45 thousand, respectively, and were recorded to paid-in capital. The total intrinsic value of stock options exercised during the three and six months ended June 30, 2010 was $12.8 million and $16.1 million, respectively. The total intrinsic value of stock options exercised during the three and six months ended June 30, 2009 was $123 thousand.

We estimate the fair value of options as of the date of grant using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the probability of option exercise, expected years until exercise and potential forfeitures. The risk-free interest rate we use is the five-year U.S. Treasury bond in effect at the date of the grant.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

The following summary reflects the status of non-vested stock options as of June 30, 2010 and changes during the year:

	Options	Weighted Average Grant Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2010	544,345	$ 15.66	$ 42.99
Vested	(72,607)	$ 11.11	$ 27.74
Granted	21,500	$ 27.95	$ 71.49
Forfeited	(22,664)	$ 16.45	$ 46.34
Non-vested as of June 30, 2010	470,574	$ 16.89	$ 46.49

We recognize compensation cost related to stock options ratably over the vesting period. Historical amounts may not be representative of future amounts as additional options may be granted. Compensation cost (including capitalized amounts) for the three months ended June 30, 2010 and 2009 totaled $967 thousand and $757 thousand, respectively. For the six months ended June 30, 2010 and 2009, compensation cost (including capitalized amounts) totaled $1.8 million and $1.4 million, respectively.

As of June 30, 2010, there was $5.5 million of unrecognized compensation cost related to non-vested stock options granted under our stock incentive plan. We expect to recognize that cost pro rata over a weighted-average period of 1.5 years.

Stockholder Rights Plan

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

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

Dividends and Stock Repurchases

In May 2010, the Board of Directors declared a cash dividend of $0.08 per share on our common stock. The dividend is payable on September 1, 2010 to stockholders of record on August 13, 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.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

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

Issuer Purchases of Equity Securities for the Quarter Ended June 30, 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
April 2010	None	NA	None	2,635,700
May 2010	None	NA	None	2,635,700
June 2010	None	NA	None	2,635,700

5. 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. 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 six months ended June 30, 2010 (in thousands):

Asset retirement obligation at January 1, 2010	$	149,310
Liabilities incurred		2,286
Liability settlements and disposals		(11,787)
Accretion expense		3,892
Revisions of estimated liabilities		1,066
Asset retirement obligation at June 30, 2010		144,767
Less current obligation		(21,263)
Long-term asset retirement obligation	$	123,504

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

6. Debt

Debt at June 30, 2010 and December 31, 2009 consisted of the following (in thousands):

	June 30, 2010	December 31, 2009
Bank debt	$	$ 25,000
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023 (face value $19,450)	17,871	17,793
Total debt	367,871	392,793
Less current maturities	(17,871)	
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 provided by a syndicate of banks led by JP Morgan Chase Bank, N.A., matures on April 14, 2012 and is secured by mortgages on certain of our oil and gas properties and the stock of certain wholly-owned operating subsidiaries.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations. The borrowing base of $1 billion and bank commitments of $800 million were reaffirmed in April 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 June 30, 2010, we were in compliance with all of the financial and non-financial covenants.

At Cimarex s option, borrowings under the credit facility may bear interest at either (a) a London Interbank Offered Rate (LIBOR) plus 2% to 3%, 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% to 2.125% based on borrowing base usage.

At June 30, 2010, there were no outstanding borrowings under the credit facility. We had letters of credit outstanding of $10.5 million leaving an unused borrowing availability of $789.5 million.

7.125% Notes due 2017

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

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 at the following redemption prices (expressed as percentages of the principal amount) plus accrued interest, if any, thereon to the date of redemption.

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

At any time prior to May 1, 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

The floating rate convertible senior notes mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On June 30, 2010, the interest rate was approximately 0.54%.

We previously repurchased $105.5 million of these borrowings at the option of the holders. On July 1, 2010, all remaining holders 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 will record a gain of approximately $3.7 million on the settlement of the notes in July 2010. As of June 30, 2010 the notes are classified as a current liability.

The debt and equity components of the instruments are accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as of the issuance date, with the remaining proceeds allocated to the equity component and recorded as additional paid-in capital. The debt component was recorded at a discount and was subsequently accreted, thereby reflecting an overall market rate of interest in the income statement. The effective interest rate for the quarters ended June 30, 2010 and 2009 was 1.2% and 2.2%, respectively. The effective interest rate for the six months ended June 30, 2010 and 2009 was 1.2% and 2.6%, respectively.

7. Income Taxes

The components of our provision for income taxes are as follows (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010		2009		2010		2009	
Current provision (benefits)	$	31,026	$	(13,625)	$	64,390	$	(28,834)
Deferred taxes (benefits)		40,313		35,632		125,303		(234,120)
	$	71,339	$	22,007	$	189,693	$	(262,954)

We account for uncertainty in our income tax provisions in accordance with rules promulgated by the FASB. At June 30, 2010 we have no unrecognized tax benefits that would impact our effective rate

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2005 2008 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities which remain open for tax years 2005 2008 for examination.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes, non-deductible expenses, and special deductions. The effective income tax rates for the six months ended June 30, 2010 and June 30, 2009 was 36.6%.

8. Supplemental Disclosure of Cash Flow Information (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Cash paid during the period for:				
Interest expense (including capitalized amounts)	$ 13,702	$ 15,513	$ 15,073	$ 17,350
Interest capitalized	$ 10,868	$ 8,494	$ 11,944	$ 9,719
Income taxes	$ 61,912	$ 1,650	$ 84,857	$ 1,670
Cash received for income taxes	$ 809	$	$ 2,675	$ 41,982

9. Earnings (Loss) per Share and Comprehensive Income (Loss)

Earnings (Loss) 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. We adopted this guidance in the first quarter of 2009.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net income (loss)	$ 124,620	$ 38,807	$ 328,981	$ (455,293)
Less distributed earnings (dividends declared during the period)	(6,774)	(5,039)	(13,533)	(10,077)
Undistributed earnings (loss) for the period	$ 117,846	$ 33,768	$ 315,448	$ (465,370)
Allocation of undistributed earnings(loss):				
Basic allocation to unrestricted common stockholders	$ 114,523	$ 32,823	$ 306,553	$ (465,370)
Basic allocation to participating securities	$ 3,323	$ 945	$ 8,895	$ (2)
Diluted allocation to unrestricted common stockholders	$ 114,558	$ 32,827	$ 306,645	$ (465,370)
Diluted allocation to participating securities	$ 3,288	$ 941	$ 8,803	$ (2)
Basic Shares Outstanding				
Unrestricted outstanding common shares (3)	82,352	81,701	82,352	81,701
Add Participating securities:				
Restricted stock outstanding	1,742	1,700	1,742	1,700
Restricted stock units outstanding	648	652	648	652
Total participating securities	2,390	2,352	2,390	2,352(2)
Total Basic Shares Outstanding	84,742	84,053	84,742	84,053
Fully Diluted Shares				
Unrestricted outstanding common shares	82,352	81,701	82,352	81,701
Incremental shares from assumed exercise of stock options	490	346	481	(1)
Incremental shares from assumed conversion of the convertible senior notes (3)	409		409	(1)
Fully diluted common stock	83,251	82,047	83,242	81,701
Participating securities	2,390	2,352	2,390	2,352(2)
Total Fully Diluted Shares	85,641	84,399	85,632	84,053
Basic earnings (loss) per share (3)				
Unrestricted common stockholders:				
Distributed earnings	$ 0.08	$ 0.06	$ 0.16	$ 0.12
Undistributed earnings (loss)	1.39	0.40	3.72	(5.70)
	$ 1.47	$ 0.46	$ 3.88	$ (5.58)
Participating securities:				

Distributed earnings	$	0.08	$	0.06	$	0.16	$	0.12
Undistributed earnings		1.39		0.40		3.72		0.00
	$	1.47	$	0.46	$	3.88	$	0.12
Fully diluted earnings (loss) per share								
Unrestricted common stockholders:								
Distributed earnings	$	0.08	$	0.06	$	0.16	$	0.12
Undistributed earnings (loss)		1.38		0.40		3.68		(5.70)
	$	1.46	$	0.46	$	3.84	$	(5.58)
Participating securities:								
Distributed earnings	$	0.08	$	0.06	$	0.16	$	0.12
Undistributed earnings		1.38		0.40		3.68		0.00
	$	1.46	$	0.46	$	3.84	$	0.12

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

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

(3) Subsequent to June 30, 2010, 408,450 shares of common stock were issued to the convertible senior note holders. Had this conversion occurred prior to June 30, 2010, it would lower the basic earnings per share by $0.01 and $0.02 for the three and six months ended June 30, 2010, respectively.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

The following table presents the amounts of outstanding stock options, restricted stock and units as follows:

	June 30,	
	2010	**2009**
Stock options	1,208,482	1,635,718
Restricted stock	1,742,111	1,700,150
Restricted units	647,507	651,672

Certain stock options and restricted units and shares were considered to be anti-dilutive as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Stock options	31,562	552,388	46,196	1,635,718
Restricted stock				1,700,150
Restricted stock units				651,672
	31,562	552,388	46,196	3,987,540

Comprehensive Income (Loss)

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

The components of comprehensive income (loss) are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss)	$ 124,620	$ 38,807	$ 328,981	$ (455,293)
Other comprehensive income (loss):				

Change in fair value of investments, net of tax		(248)		281		(149)		516
Total comprehensive income (loss)	$	124,372	$	39,088	$	328,832	$	(454,777)

10. Commitments and Contingencies

Litigation

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million 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. 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 the first half of 2010, we have accrued an additional $9.4 million and $4.4 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

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

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.

Other

We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At June 30, 2010, we had commitments of $127.9 million relating to construction of the gas processing plant of which $72.8 million is subject to a construction contract. The total cost of the project will approximate $351 million. Pursuant to the terms of our operating agreement with our partners in this project, we will be reimbursed by them for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

We have drilling commitments of approximately $79.6 million consisting of obligations to complete drilling wells in progress at June 30, 2010. We also have minimum expenditure contractual commitments of $41.1 million to secure the use of drilling rigs.

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

At June 30, 2010, we had firm sales contracts to deliver approximately 8.5 Bcf of natural gas over the next nine months. If this gas is not delivered, our financial commitment would be approximately $33.6 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 47.4 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 $40.5 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 $3.1 million, some of which would 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.

11. Property Sales and Acquisitions

During the first half of 2010 we had property acquisitions of $33.9 million, primarily for additional interests in our Anadarko Basin, Cana-Woodford shale play.

Table of Contents

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

June 30, 2010

(Unaudited)

Various interests in oil and gas properties were sold during the first six months of 2010 for $28.8 million, which was recorded as a reduction to oil and gas properties. Most of these divestments were our Mississippi assets.

Table of Contents

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS OVERVIEW

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

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

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

Our exploration and development capital investment is projected to be in the range of $900 million to $1 billion in 2010, depending on commodity prices and corresponding operating cash flow. Due to lower commodity prices in 2009 we sharply reduced our capital investments. In 2009, our investments in exploration, development and acquisition activities totaled $528 million. At June 30, 2009 we had seven operated rigs running. At June 30, 2010 we had 19 operated rigs running. Our 2010 drilling is primarily directed towards our western Oklahoma, Cana-Woodford shale, southeast New Mexico Permian Basin horizontal oil and southeast Texas Gulf Coast Yegua programs.

Second quarter 2010 summary financial and operating results:

- Second quarter production volumes averaged 594.4 MMcfe/d, up from 453.9 MMcfe/d for second quarter 2009.

- Second quarter sales of oil, gas and NGLs increased 71% to $364.9 million from $213.4 million a year earlier.

- The average realized oil price increased 36% to $75.26 per barrel compared to $55.27 per barrel in 2009.

- The average realized gas price increased 29% to $4.48 per Mcf versus $3.48 per Mcf in 2009.

- The average realized NGL price increased 2% to $33.45 per barrel compared to $32.69 per barrel in 2009.

- Cash flow from operating activities was $273.2 million, up from $111.8 million a year earlier.

Table of Contents

- Net income of $124.6 million ($1.46 per diluted share) increased from net income of $38.8 million ($0.46 per diluted share) in 2009.

- Debt totaled $367.9 million at June 30, 2010, down from $392.8 million at year-end 2009.

- Second quarter 2010 drilling included 52 gross (32.4 net) wells, with 50 gross (31.1 net) completed as producers. In the second quarter of 2009 we drilled 24 gross (11 net) wells with 96% completed as producers. At June 30, 2010, 33 gross (16.5 net) wells were in the process of being completed or were awaiting completion.

Commodity Prices

While our revenues are a function of both production and prices, wide swings in prices have had the greatest impact on our results of operations. The following table presents our average realized commodity prices for the second quarter and first six months of 2010, versus the same periods of 2009.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Gas Prices:				
Average Henry Hub price ($/Mcf)	$ 4.09	$ 3.51	$ 4.70	$ 4.21
Average realized sales price ($/Mcf)	$ 4.48	$ 3.48	$ 5.47	$ 3.66
Oil Prices:				
Average WTI Cushing price ($/Bbl)	$ 78.04	$ 59.63	$ 78.38	$ 51.35
Average realized sales price ($/Bbl)	$ 75.26	$ 55.27	$ 75.69	$ 45.09
NGL Prices:				
Average realized sales price ($/Bbl)	$ 33.45	$ 32.69	$ 35.07	$ 30.66

On an energy equivalent basis, 65% of our aggregate 2010 production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in approximately a $6.9 million change in our gas revenues. Similarly, 35% of our production was crude oil and NGLs. A $1.00 per barrel change in our average realized sales price would have resulted in approximately a $6.3 million change in our combined 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 March 2009 we entered into derivative gas contracts covering the period April 2009 through December 2009. During the second and third quarters of 2009 we entered into derivative contracts for a portion of our 2010 oil and gas production. As of June 30, 2010, the remaining 2010 contracts cover approximately 37% of our anticipated remaining 2010 oil and gas production volumes.

In the first and second quarters of 2010 we entered into derivative contracts for a portion of our 2011 oil and gas production. Management has been authorized to hedge up to 50% of our anticipated 2011 equivalent oil and gas production. Subsequent to June 30, 2010 we entered into additional derivative contracts relative to our 2011 oil and gas production.

Table of Contents

We had the following outstanding contracts as of June 30, 2010:

Natural Gas Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Ceiling	Swap	Fair Value (000 s)
Jul 10 - Dec 10	Collar	100,000 MMBtu	PEPL	$ 5.00	$ 6.62		$ 13,655
Jul 10 - Dec 10	Swap	40,000 MMBtu	PEPL			$ 5.18	$ 5,436
Jul 10 - Dec 10	Collar	20,000 MMBtu	HSC	$ 5.00	$ 6.85		$ 2,107
Jan 11 Dec 11	Swap	10,000 MMBtu	PEPL			$ 5.10	$ 401

Oil Contracts

Period	Type	Volume/Day	Index(1)	Weighted Average Price Floor	Ceiling	Fair Value (000 s)
Jul 10 - Dec 10	Collar	10,000 Bbls	WTI	$ 60.03	$ 92.07	$ (456)
Jul 10 - Dec 10	Put/Floor	1,000 Bbls	WTI	$ 60.00	$	$ 153
Jan 11 - Dec 11	Collar	6,000 Bbls	WTI	$ 65.00	$ 106.20	$ 3,927

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

We have chosen not to apply hedge accounting treatment to any of our derivative contracts 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 Note 2 to the Consolidated Financial Statements and Item 3 of this report for additional information regarding our derivative instruments.

Production and other operating expenses

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

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 commodity 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

Table of Contents

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.

Table of Contents

RESULTS OF OPERATIONS

Three months and six months ended June 30, 2010 vs. June 30, 2009

Net income for the second quarter of 2010 was $124.6 million, or $1.46 per diluted share. This compares to $38.8 million, or $0.46 per diluted share, for the same period in 2009. The increase in net income is mainly due to the improvement of realized commodity prices and increased production in the second quarter of 2010 compared to 2009. For the six months ended June 30, 2010 net income was $329.0 million, or $3.84 per diluted share. In 2009 we recognized a net loss of $455.3 million, or $5.58 per share, for the first six months of the year. The increase in net income is primarily driven by the improvement of realized commodity prices and increased production in the first six months of 2010 compared to 2009. In addition, in the first quarter of 2009 we recorded a 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 (In thousands or as indicated)	**2010**	**2009**	**Percent Change Between 2010/2009**	**Price/Volume Analysis** Price	Volume	Variance
For the Three Months Ended June 30,						
Gas sales	$ 151,375	$ 100,539	51%	$ 33,793	$ 17,043	$ 50,836
Oil sales	180,664	110,850	63%	47,996	21,818	69,814
NGL Sales	32,851	1,979	1560%	746	30,126	30,872
	$ 364,890	$ 213,368		$ 82,535	$ 68,987	$ 151,522
For the Six Months Ended June 30,						
Gas sales	$ 377,012	$ 217,163	74%	$ 124,832	$ 35,017	$ 159,849
Oil sales	372,224	190,187	96%	150,491	31,546	182,037
NGL Sales	48,060	3,247	1380%	6,042	38,771	44,813
	$ 797,296	$ 410,597		$ 281,365	$ 105,334	$ 386,699

	For the Three Months Ended June 30, 2010	2009	**Percent Change Between 2010/2009**	**For the Six Months Ended June 30,** 2010	2009	**Percent Change Between 2010/2009**
Total gas volume MMcf	33,793	28,910	17%	68,968	59,375	16%
Gas volume - MMcf per day	371.4	317.7		381.04	328.04	
Average gas price - per Mcf	$ 4.48	$ 3.48	29%	$ 5.47	$ 3.66	49%
Total oil volume - thousand barrels	2,401	2,006	20%	4,918	4,218	17%
Oil volume - barrels per day	26,381	22,040		27,170	23,304	
Average oil price - per barrel	$ 75.26	$ 55.27	36%	$ 75.69	$ 45.09	68%
Total NGL volume thousand barrels	982	61	1510%	1,370	106	1192%
NGL volume barrels per day	10,792	665		7,570	585	
Average NGL price per barrel	$ 33.45	$ 32.69	2%	$ 35.07	$ 30.66	14%

Commodity sales for the second quarter of 2010 totaled $364.9 million, compared to $213.4 million in 2009. The increase of $151.5 million between the two periods resulted from higher commodity prices, which had a positive impact of $82.5 million. In addition, higher production volumes during the current quarter contributed an increase of $69 million, compared to the prior year.

For the first six months of 2010 commodity sales totaled $797.3 million. For the same period in 2009, commodity sales were $410.6 million. The $386.7 million increase resulted from higher commodity prices ($281.4 million) and higher production volumes ($105.3 million).

In the second quarter of 2010 our gas production averaged 371.4 MMcf per day, compared to 317.7 MMcf per day in 2009. This 17% increase resulted in $17 million of incremental revenues for the quarter. During the first six months of 2010 our daily gas production averaged 381 MMcf per day, or a

Table of Contents

16% increase over the 2009 average of 328 MMcf per day. This increase contributed an additional $35 million of revenue to the first six months of 2010.

Our oil production during the second quarter of 2010 averaged 26.4 thousand barrels per day. For the same period of 2009 our average daily oil production was 22 thousand barrels per day. The 20% increase in oil production for the quarter contributed an additional $21.8 million of sales revenue. During the first six months of 2010 we averaged 27.2 thousand barrels per day, up from 23.3 thousand barrels per day in 2009, a 17% increase, which added $31.5 million of revenue.

Our second quarter 2010 NGL volumes increased to 10.8 thousand barrels per day compared to 665 barrels per day in 2009. This increase contributed $30.1 million of revenue. NGL production for the first six months of 2010 averaged 7.6 thousand barrels a day, compared to 585 barrels a day in 2009. This increase provided $38.8 million of revenue. NGL production volumes are recorded based on where title transfer occurs. Ongoing contract amendments have contributed to a higher level of NGL sales in 2010. In prior years these volumes were reported as gas sales.

The increases in our 2010 production volumes reflect our positive drilling results in our Yegua/Cook Mountain play in the southeast Texas Gulf Coast area, and in our western Oklahoma Cana-Woodford shale play. The increase in our 2010 NGL production is also primarily attributable to production from these two areas.

In the second quarter of 2010 we realized an average gas price of $4.48 per Mcf, or an increase of 29% compared to the average price received of $3.48 per Mcf for the second quarter of 2009. Our average realized gas price for the first six months of 2010 of $5.47 per Mcf was 49% higher than the 2009 average realized price of $3.66. These price increases resulted in increased gas sales revenues of $33.8 million for the second quarter of 2010 and $124.8 million for the first six months of 2010.

We realized an average oil price of $75.26 per barrel for the second quarter of 2010 versus $55.27 for the same period of 2009. This 36% increase resulted in additional oil sales revenue of $48 million. For the first six months of 2010 we realized an average oil price of $75.69 per barrel, which was 68% higher than the average price of $45.09 we received for the same period in 2009. This increase contributed an additional $150.5 million of oil sales revenue for the six months ended June 30, 2010.

Our average realized price for NGL s in the first quarter of 2010 was $33.45 per barrel. This price was 2% higher than the $32.69 average price received in the first quarter of 2009, and accounted for additional NGL revenue of $746 thousand. In the first six months of 2010 the average NGL price we received was $35.07, up from $30.66 for the same period of 2009. The 14% price increase for 2010 raised NGL sales by $6 million for the first six months of 2010.

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

Gas Gathering, Processing, Marketing and Other	For the Three Months Ended June 30,	For the Six Months Ended June 30

(In Thousands):		2010		2009		2010		2009
Gas gathering, processing and other revenues	$	13,602	$	9,363	$	29,452	$	20,433
Gas gathering and processing costs		(6,100)		(4,411)		(12,605)		(9,517)
Gas gathering, processing and other margin	$	7,502	$	4,952	$	16,847	$	10,916
Gas marketing revenues, net of related costs	$	9	$	(46)	$	323	$	834

We sometimes transport, process and market third-party gas that is associated with our gas. In the second quarter of 2010, third-party gas gathering, processing and other contributed $7.5 million of pre-tax cash operating margin (revenues less direct cash expenses) versus $5.0 million in 2009. For the

Table of Contents

six months ended June 30, 2010 and 2009, such revenues less direct cash expenses totaled $16.8 million and $10.9 million, respectively. Our gas marketing margin (revenues less purchases) was $9 thousand for the second quarter of 2010, compared to a net loss of $46 thousand in 2009. For the first six months of 2010 our gas marketing margin decreased to $323 from $834 thousand in the 2009 period. Changes in net margins from gas gathering, processing, marketing and other activities are the direct result of changes in volumes and overall market conditions.

Operating costs and expenses (In Thousands):	**For the Three Months Ended June 30, 2010**	**2009**	**Variance Between 2010/2009**	**For the Six Months Ended June 30, 2010**	**2009**	**Variance Between 2010/2009**
Impairment of oil and gas properties	$	$	$	$	$ 791,137	$ (791,137)
Depreciation, depletion and amortization	73,146	56,885	16,261	142,856	146,551	(3,695)
Asset retirement obligation	1,641	2,096	(455)	4,285	4,641	(356)
Production	45,356	46,031	(675)	87,339	96,445	(9,106)
Transportation	10,825	7,764	3,061	21,992	16,473	5,519
Taxes other than income	28,410	15,252	13,158	60,768	30,797	29,971
General and administrative	11,817	9,519	2,298	24,862	17,281	7,581
Stock compensation	2,993	2,097	896	5,771	4,354	1,417
(Gain) loss on derivative instruments, net	(3,289)	358	(3,647)	(55,886)	256	(56,142)
Other operating, net	1,876	6,091	(4,215)	30	16,183	(16,153)
	$ 172,775	$ 146,093	$ 26,682	$ 292,017	$ 1,124,118	$ (832,101)

Total operating costs and expenses (not including gas gathering, marketing and processing costs, or income tax expense) increased to $172.8 million in the second quarter of 2010 compared to $146.1 million for the second quarter of 2009.

For the first six months of 2010 total operating costs and expenses decreased $832.1 million to $292 million versus $1.1 billion in 2009. The largest component of the decrease is the non-cash impairment of oil and gas properties of $791 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. (See Note 1 to the Consolidated Financial Statements where the full cost method of accounting is discussed in detail.) Excluding the $791.1 million impairment, operating costs and expenses for the 2009 six month period were $333 million, or $41 million more than the $292 million for the first six months of 2010.

DD&A increased from $56.9 million in the second quarter of 2009 to $73.1 million in the same period of 2010. On a unit of production basis, DD&A was $1.35 per Mcfe for both periods. The increase in expense is primarily a result of higher production for the second quarter of 2010. For the first six months of 2010 DD&A was $142.9 million, compared to $146.6 million in 2009. On a unit of production basis, the six month rate for 2010 was $1.34 per Mcfe, down from $1.72 per Mcfe for the 2009 period. The decrease in the rate per Mcfe is due to the impairment of oil and gas properties in the first quarter of 2009. The decrease in expense resulting from the decrease in the DD&A rate was partially offset by increased expense related to higher production volumes for the 2010 period.

Our production costs consist of workover expense and lease operating expense. Aggregate costs for the second quarter of 2010 compared to those of 2009 remained relatively flat. However, our cost per Mcfe decreased $0.27 per Mcfe from $1.11 in the second quarter of 2009 to $0.84 per Mcfe for 2010. Production costs for the first six months of 2010 were $87.3 million ($0.82 per Mcfe), down 9 percent from $96.4 million ($1.13 per Mcfe) for the same period of 2009. Both the quarter and first six months of 2010 had lower lease operating expenses as a result of decreases in service costs due to a continuing focus on efficiencies in production operations. Property divestitures of non-core producing properties subsequent to June 30, 2009 also contributed to the decreases in lease operating expense in 2010. Workover expenses were relatively constant for both periods of 2010, compared to 2009.

Table of Contents

Transportation costs rose to $10.8 million ($0.20 per Mcfe) in the second quarter of 2010 from $7.8 million ($0.19 per Mcfe) in 2009. For the first six months of 2010 transportation costs were $22 million ($0.21 per Mcfe) versus $16.5 million ($0.19 per Mcfe) for 2009. Transportation costs will fluctuate based on increases or decreases in sales volumes and fluctuation in the price of the fuel cost component. Also, in the first six months of 2010 we recorded $1.3 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 in the second quarter of 2010 were $13.2 million higher, increasing from $15.3 million in the second quarter of 2009 to $28.4 million in 2010. For the six months ended June 30, 2010, taxes other than income were $60.8 million, up $30 million compared to $30.8 million for the 2009 period. The increased taxes between periods resulted from increases in production volumes and from higher realized commodity prices in the 2010 periods.

For the second quarter of 2010 our general and administrative (G&A) expense was $11.8 million, up $2.3 million compared to G&A expense of $9.5 million for the same period of 2009. G&A expense for the first half of 2010 increased $7.6 million from $17.3 million in 2009 to $24.9 million in 2010. Higher employee benefits related to increases in accrued bonus and profit sharing expenses in the 2010 periods contributed to the increases in G&A expense. Charitable contributions were also higher in the second quarter and first six months of 2010, compared to 2009.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock, restricted stock units and stock option awards. Stock compensation expense in the second quarter of 2010 was $3 million, up from $2.1 million in the second quarter of 2009. For the first six months of 2010, stock compensation expense rose $1.4 million to $5.8 million, compared to $4.4 million for the same period of 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 4 to the Consolidated Financial Statements 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 2009 and 2010. (See Note 2 to the Consolidated Financial Statements for a complete discussion of our derivative instruments).

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
Realized (gain) loss on settlement of derivative instruments	$ (16,570)	$ (3,369)	$ (17,111)	$ (3,369)
Unrealized (gain) loss from changes to the fair value of the derivative instruments	13,281	3,727	(38,775)	3,625

(Gain) loss on derivative instruments, net	$	(3,289)	$	358	$	(55,886)	$	256

Table of Contents

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. For the second quarter of 2010 these costs were $1.9 million compared to $6.1 million for 2009. Other operating, net decreased from $16.2 million for the first six months of 2009 to $30 thousand for the same period of 2010. The decreases resulted primarily from contract settlements and the resolution of certain legal matters in 2010.

Other income and expense

Interest expense for the second quarter of 2010 was $9.1 million compared to $11.3 million for 2009. The decrease of $2.2 million is primarily due to lower interest expense for bank debt. During the second quarter of 2010 we did not have any bank debt outstanding. During the second quarter of 2009 our average bank debt outstanding was $375 million. For the first six months of 2010 our interest expense was $18.6 million versus $19.5 million for the same period of 2009. The $900 thousand decrease resulted primarily from lower average bank debt outstanding during the first half of 2010 compared to 2009. The lower interest expense was mostly offset by additional expense in 2010 for deferred financing costs associated with our credit facility, which we entered into in April of 2009.

Components of other, net consist of miscellaneous income and expense items that will vary from period to period, including income and loss from equity investees, gain or loss on the sale or value of oil and gas well equipment and interest income. For the second quarter of 2010 other, net decreased to $1.9 million of expense, down from $5.5 million in the second quarter of 2009. Other, net decreased from $7.9 million of expense in the first six months of 2009 to $79 thousand of income in the second quarter of 2010. The decreases in expense from 2009 compared to 2010 are primarily the result of losses in the 2009 periods related to oil and gas well equipment. Due to the significant slowing of drilling activity across the industry in 2009, the value of drill pipe decreased.

Income tax expense

In the second quarter of 2010 we recognized $71.3 million of income tax expense, of which $31 million is current. This compares with second quarter 2009 income tax expense of $22 million which included a $13.6 million current tax benefit. The combined Federal and state effective income tax rates were 36.4% and 36.2% for the second quarters of 2010 and 2009, respectively. For the first six months of 2010 we recognized net income tax expense of $189.7 million (of which $64.4 million is current). For the same period of 2009 we recorded an income tax benefit of $263 million (including a current tax benefit of $28.8 million). The combined Federal and state effective income tax rates for the first six months of 2010 and 2009 was 36.6% for both periods. Our effective tax rates differ from the statutory rate of 35% due to state income taxes, non-deductible expenses and special deductions.

Table of Contents

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 ongoing turmoil in our economy and the global financial system may negatively impact realized commodity prices. Volatility in prices may reduce the amount of oil and gas that we can economically produce. Commodity prices also affect the amount of cash flow available for capital expenditures as well as our ability to borrow and raise additional capital. These conditions could impact third parties with whom we do business, causing them to fail to meet their obligations to us.

We intend to deal with volatility in the current economic environment by maintaining a portfolio of exploration and development opportunities including our Anadarko Basin, Cana-Woodford shale gas development, our Permian Basin horizontal oil plays and our higher-risk geo-physically driven Gulf Coast drilling program.

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

In addition, we will consider attractive acquisition opportunities. However, the timing and size of acquisitions are unpredictable. To ready ourselves for potential acquisitions and further 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.

At June 30, 2010, our total debt outstanding was $367.9 million, with long-term debt of $350 million. Our debt to total capitalization ratio was 13%. 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 $2.368 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 2010 and beyond.

Analysis of Cash Flow Changes

Cash flow provided by operating activities for the first six months of 2010 was $572.3 million, compared to $194.4 million for the same period of 2009. The $378 million increase in 2010 resulted primarily from higher revenues attributable to higher commodity prices and production volumes.

Cash flow used in investing activities for the first six months of 2010 was $412.8 million, compared to $283.7 million for 2009. Changes in the cash flow used in investing activities are generally the result of changes in our exploration and development programs, acquisitions and property sales. The $129.1 million increase from second quarter 2009 to 2010 was due mainly to increased cash expenditures related to property acquisitions and increased exploration and development activity in 2010. See the discussion below for further information regarding our capital expenditures.

Table of Contents

Net cash flow used for financing activities in the first six months of 2010 was $19.9 million versus net cash flow provided by financing activities of $91.1 million for the same period of 2009. In 2009 we had net borrowings under our credit facility of $119.0 million. In the first six months of 2010 we had net payments to our credit facility of $25 million, resulting in zero bank debt outstanding at June 30, 2010.

Reconciliation of Cash Flow from Operations

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
	(In thousands)			
Net cash provided by operating activities	$ 273,153	$ 111,790	$ 572,260	$ 194,346
Change in operating assets and liabilities	(13,259)	41,318	841	96,408
Cash flow from operations	$ 259,894	$ 153,108	$ 573,101	$ 290,754

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.

Capital Expenditures

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

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
Acquisitions:				
Proved	$ 6,630	$ 49	$ 13,786	$ 124
Unproved	4,022		20,066	
	10,652	49	33,852	124
Exploration and development:				
Land and seismic	38,258	10,757	63,161	27,036
Exploration and development	199,200	87,948	366,886	213,700
	237,458	98,705	430,047	240,736
Sales proceeds:				
Proved	(24,861)	(14,664)	(24,861)	(15,394)
Unproved	(3,917)		(3,917)	(3,034)
	(28,778)	(14,664)	(28,778)	(18,428)
	$ 219,332	$ 84,090	$ 435,121	$ 222,432

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

Our exploration and development expenditures increased 79% in the first half of 2010 compared to the same period of 2009. Due to significantly lower commodity prices in 2009, we sharply reduced our development and exploration activities, especially in the first half of the year. At June 30, 2009 we had seven operated rigs running. At June 30, 2010 we had 19 operated rigs running.

In the first half of 2010 we drilled and completed 89 gross (55.5 net) wells, with 84 gross (52.2 net) completed as producers. At June 30, 2010 we also had 33 gross (16.5 net) wells that were in

Table of Contents

the process of being completed or were awaiting completion. During the same period of 2009 we drilled and completed 65 gross (35 net) wells, completing 95% as producers.

Our planned exploration and development program for 2010 is expected to range from $900 million to $1 billion, depending on commodity prices and corresponding cash flow. Although our capital budget is set at a level that we believe corresponds with our anticipated cash flows, the timing of capital expenditures and the receipt of cash flows do not necessarily match. We may borrow and repay funds under our credit arrangement throughout the year. For example, our planned capital expenditures are front-end loaded and we may outspend cash flows for a period of time. If we start to see a significant change in commodity prices from our current forecasts, we have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations.

During the first six months of 2010 we had property acquisitions of $33.9 million, primarily for additional interests in our Anadarko Basin, Cana-Woodford shale play. We also had land and seismic purchases of $63.2 million, of which nearly 70% was in the Permian Basin. Subsequent to June 30, 2010, we agreed to acquire additional interests in our Cana-Woodford shale play for approximately $1 million.

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 $351 million. Pursuant to the terms of our operating agreement with our partners in this project, we are reimbursed by them for 42.5% of the costs. Through June 30, 2010 our cumulative investment in this project is approximately $89 million, of which $67 million is included in our fixed assets. At present we expect to initiate gas sales from this project in 2011.

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.

Financial Condition

During the first half of 2010 our total assets increased by $426 million to $3.8 billion, up from $3.4 billion at December 31, 2009. Our current assets contributed $120 million to the total increase. The increase in current assets resulted from increases in our cash and cash equivalents and derivative instruments, which were partially offset by a decrease in our oil and gas well equipment and supplies. In addition, our net oil and gas assets increased during the first six months of 2010 by $304 million. Our liability for deferred income taxes increased over the first six months of the year by $107 million, as a result of our increase in net income for the period. As of June 30, 2010, stockholders equity totaled $2.4 billion, up from $2.0 billion at December 31, 2009. The increase is also a result of our net income for the first half of 2010.

Dividends

On February 25, 2010 the Board of Directors increased our regular cash dividend on our common stock from $0.06 to $0.08 per common share. Future dividend payments will depend on the Company s level of earnings, financial requirements, and other factors considered relevant by our Board of Directors.

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

Table of Contents

of $37.93. Cumulative purchases through December 31, 2007 total 1,364,300 shares at an average price of $39.05. There were no shares repurchased in the first half of 2010, or since the quarter ended September 30, 2007.

Working Capital

Working capital increased $88 million from year-end 2009 to $106 million at June 30, 2010. Working capital increased primarily because of the following:

- Cash and cash equivalents increased by $140 million primarily due to increases in commodity prices and production volumes.
- The aggregate fair value of our derivative instruments increased by $22 million.
- Other current assets increased by $18 million due to increases in advances and prepaid expenses.

These working capital increases were partially offset by:

- Oil and gas well equipment and supplies decreased by $34 million as supplies were used in the first half of the year s drilling activities.
- A decrease of $16 million related to our deferred tax asset as of June 30, 2010.
- As of June 30, 2010 we had $18 million of current maturity of long-term debt related to our floating rate convertible notes. At December 31, 2010 we did not have any debt that was classified as current.
- An increase of $33 million of accrued liabilities related to our increased drilling activity.

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 June 30, 2010 and December 31, 2009 consisted of the following (in thousands):

	June 30, 2010	December 31, 2009
Bank debt	$	$ 25,000
7.125% Notes due 2017	350,000	350,000
Floating rate convertible notes due 2023 (face value $19,450)	17,871	17,793
Total debt	367,871	392,793
Less current maturities	(17,871)	
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 provided by a syndicate of banks led by JP Morgan Chase Bank, N.A., matures on April 14, 2012 and is secured by mortgages on certain of our oil and gas properties and the stock of certain wholly-owned operating subsidiaries.

Table of Contents

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 April 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 June 30, 2010, we were in compliance with all of the financial and non-financial covenants.

At Cimarex s option, borrowings under the credit facility may bear interest at either (a) a London Interbank Offered Rate (LIBOR) plus 2% to 3%, 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% to 2.125% based on borrowing base usage.

At June 30, 2010, there were no outstanding borrowings under the credit facility. We had letters of credit outstanding of $10.5 million leaving an unused borrowing availability of $789.5 million.

7.125% Notes due 2017

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

The notes are redeemable at our option, in whole or in part, at any time on and after May 1, 2012 at the following redemption prices (expressed as percentages of the principal amount) plus accrued interest, if any, thereon to the date of redemption.

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

At any time prior to May 1, 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

The floating rate convertible senior notes mature on December 15, 2023. The notes are senior unsecured obligations and bear interest at the three month LIBOR, reset quarterly. On June 30, 2010, the interest rate was approximately 0.54%.

We previously repurchased $105.5 million of these borrowings at the option of the holders. On July 1, 2010, all remaining holders elected to convert their notes for cash and shares. In July 2010 the

Table of Contents

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 will record a gain of approximately $3.7 million on the settlement of the notes in July 2010. As of June 30, 2010 the notes are classified as a current liability.

The debt and equity components of the instruments are accounted for separately. The value assigned to the debt component is the estimated value of similar debt without a conversion feature as of the issuance date, with the remaining proceeds allocated to the equity component and recorded as additional paid-in capital. The debt component was recorded at a discount and was subsequently accreted, thereby reflecting an overall market rate of interest in the income statement. The effective interest rate for the quarters ended June 30, 2010 and 2009 was 1.2% and 2.2%, respectively. The effective interest rate for the six months ended June 30, 2010 and 2009 was 1.2% and 2.6%, respectively.

Contractual Obligations and Material Commitments

At June 30, 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)	$ 369,450	$ 19,450	$	$	$ 350,000
Fixed-Rate interest payments(1)	174,563	24,938	49,875	49,875	49,875
Operating leases	20,058	5,684	10,251	4,123	
Drilling commitments(2)	120,707	98,624	22,083		
Purchase commitments(3)	11,051	11,051			
Gas processing facility(4)	72,848	30,327	17,825	24,696	
Asset retirement obligation	144,767	21,263	(5)	(5)	(5)
Other liabilities(6)	61,409	10,748	21,279	20,029	9,353

(1) See item 3: Interest Rate Risk for more information regarding fixed and variable rate debt.

(2) We have drilling commitments of approximately $79.6 million consisting of obligations to complete drilling wells in progress at June 30, 2010. We also have minimum expenditure contractual commitments of $41.1 million to secure the use of drilling rigs.

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

(4) We have a large development project in Sublette County, Wyoming where we are developing the deep Madison gas formation and constructing a gas processing plant. At June 30, 2010, we had commitments of $127.9 million relating to construction of the gas processing plant of which $72.8 million is subject to a construction contract. The total cost of the project will approximate $351 million. Pursuant to the

terms of our operating agreement with our partners in this project, we will be reimbursed by them for 42.5% of the costs. The gas processing plant is subject to a delivery commitment agreement over a 20 year period, commencing December, 2011. If no deliveries were made, the maximum amount that would be payable under the agreement would be approximately $43 million.

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

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

At June 30, 2010, we had firm sales contracts to deliver approximately 8.5 Bcf of natural gas over the next nine months. If this gas is not delivered, our financial commitment would be approximately $33.6 million. This commitment will fluctuate due to price volatility and actual volumes delivered.

Table of Contents

However, we believe no significant 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 47.4 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 $40.5 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 $3.1 million, some of which would be reimbursed by working interest owners who are selling with us under our marketing agreements.

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

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

2010 Outlook

Our exploration and development expenditures program for 2010 is projected to range from $900 million to $1 billion, which we expect to be less than 2010 cash flow. Though there are a variety of factors that could curtail, delay or even cancel some of our planned operations, we believe our projected program is likely to occur. The majority of projects are in hand, drilling rigs are being scheduled, and the historical results of our drilling efforts warrant pursuit of the projects. It is also possible that we may increase our level of planned capital investment if our commodity prices exceed our current expectation or if attractive new opportunities arise. Our 2010 drilling is primarily directed towards our western Oklahoma, Cana-Woodford shale, southeast New Mexico Permian Basin horizontal oil and southeast Texas Gulf Coast Yegua programs.

Production estimates for 2010 range from 585 to 605 MMcfe per day. Revenues from production will be dependent not only on the level of oil and gas actually produced, but also the prices that will be realized. During 2009, our realized prices averaged $4.12 per Mcf of gas, $56.63 per barrel of oil, and $37.11 per barrel of NGL. Prices can be very volatile. The possibility of 2010 realized prices being different than they were in 2009 is high.

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

	2010			
Production expense	$ 0.80	-	$	1.00
Transportation expense	0.19	-		0.24
DD&A and Asset retirement obligation	1.30	-		1.60
General and Administrative	0.22	-		0.28
Production taxes (% of oil and gas revenue)	7.5%	-		8.5%

Table of Contents

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies related to oil and gas reserves, full cost accounting, goodwill, derivatives, contingencies and asset retirement obligations to be critical policies and estimates. These critical policies and estimates are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K.

Recent Accounting Developments

There have been no significant accounting standards applicable to Cimarex issued during the quarter ended June 30, 2010.

Table of Contents

ITEM 3. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

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

Price Fluctuations

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

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

The following table details the contracts we have in place as of June 30, 2010:

Natural Gas Contracts

				Weighted Average Price			Fair Value
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**Swap**	**(000 s)**
Jul 10 - Dec 10	Collar	100,000 MMBtu	PEPL	$ 5.00	$ 6.62		$ 13,655
Jul 10 - Dec 10	Swap	40,000 MMBtu	PEPL			$ 5.18	$ 5,436
Jul 10 - Dec 10	Collar	20,000 MMBtu	HSC	$ 5.00	$ 6.85		$ 2,107
Jan 11 Dec 11	Swap	10,000 MMBtu	PEPL			$ 5.10	$ 401

Oil Contracts

				Weighted Average Price		Fair Value
Period	**Type**	**Volume/Day**	**Index(1)**	**Floor**	**Ceiling**	**(000 s)**
Jul 10 - Dec 10	Collar	10,000 Bbls	WTI	$ 60.03	$ 92.07	$ (456)
Jul 10 - Dec 10	Put/Floor	1,000 Bbls	WTI	$ 60.00	$	$ 153
Jan 11 - Dec 11	Collar	6,000 Bbls	WTI	$ 65.00	$ 106.20	$ 3,927

---

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

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the 2010 and 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 $3.3 million. For the 2010 and 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 $4.2 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. Our commodity derivative contracts are held with eight separate counterparties. Second, our derivative contracts are held with investment grade counterparties that are a part of our credit facility. See Note 2 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Table of Contents

Interest Rate Risk

At June 30, 2010, our debt was comprised of the following (in thousands):

	Fixed Rate Debt	Variable Rate Debt
7.125% Notes due 2017	350,000	
Floating rate convertible notes due 2023 (face value $19,450)		17,871
Total debt	$ 350,000	$ 17,871

Our senior unsecured notes bear interest at a fixed rate of 7.125% and will mature on May 1, 2017. Our unsecured convertible senior notes were paid out in July, 2010. Therefore, no interest rate exposure exists for the convertible notes.

At June 30, 2010 we consider our interest rate exposure to be minimal because significantly all of our debt was at a fixed rate. This assessment for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 6 to the Consolidated Financial Statements in this report for additional information regarding debt.

Table of Contents

ITEM 4. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our management, with the participation of our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e)) as of June 30, 2010 and concluded that the disclosure controls and procedures are effective in providing reasonable assurance that the information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow such persons to make timely decisions regarding required disclosures.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is also based upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives, and our CEO and CFO have concluded, as of June 30, 2010, that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in our internal controls over financial reporting or in other factors that occurred during the fiscal quarter ended June 30, 2010, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Table of Contents

PART II

ITEM 6 EXHIBITS

31.1 Certification of F. H. Merelli, Chief Executive Officer of Cimarex Energy Co. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of F. H. Merelli, Chief Executive Officer of Cimarex Energy Co. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.

32.2 Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.

101 The following materials from the Cimarex Energy Co. Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, formatted in XBRL (eXtensible Business Reporting Language) includes (i) the Consolidated Statements of Operations, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, and (iv) Notes to the Consolidated Financial Statements, tagged as blocks of text.*

---

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

Table of Contents

SIGNATURE

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

August 4, 2010

CIMAREX ENERGY CO.

/s/ Paul Korus
Paul Korus
Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ James H. Shonsey
James H. Shonsey
Vice President, Chief Accounting Officer and Controller
(Principal Accounting Officer)