CIMAREX ENERGY CO
Form 10-Q
May 07, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

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

For the Quarterly Period ended March 31, 2014

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 No

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 No

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No .

The number of shares of Cimarex Energy Co. common stock outstanding as of March 31, 2014 was 87,033,110.

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GLOSSARY

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

Bbls—Barrels (of oil or natural gas liquids)

Bcf—Billion cubic feet

Bcfe—Billion cubic feet equivalent

Btu—British thermal unit

MBbls—Thousand barrels

Mcf—Thousand cubic feet (of natural gas)

Mcfe—Thousand cubic feet equivalent

MMBbl/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 or NGLs—Natural gas liquids

Tcf—Trillion cubic feet

Tcfe—Trillion cubic feet equivalent

Energy equivalent is determined using the ratio of one barrel of crude oil, condensate or NGL to 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, gas, and NGLs 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 or areas due to mechanical, transportation, 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 economic, 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.

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PART I

ITEM 1 - Financial Statements

CIMAREX ENERGY CO.

Condensed Consolidated Balance Sheets

	March 31, 2014 (Unaudited)	December 31, 2013
	(in thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 4,530	$ 4,531
Restricted cash	818	818
Receivables, net	403,283	367,754
Oil and gas well equipment and supplies	84,339	66,772
Deferred income taxes	14,358	16,854
Derivative instruments	3	4,268
Prepaid expenses	6,939	7,867
Other current assets	408	275
Total current assets	514,678	469,139
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	13,212,174	12,863,961
Unproved properties and properties under development, not being amortized	713,195	585,361
	13,925,369	13,449,322
Less — accumulated depreciation, depletion and amortization	(7,650,755)	(7,483,685)
Net oil and gas properties	6,274,614	5,965,637
Fixed assets, net	159,824	146,918
Goodwill	620,232	620,232
Other assets, net	49,287	51,209
	$ 7,618,635	$ 7,253,135
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 140,720	$ 116,110
Accrued liabilities	411,352	412,495
Derivative instruments	7,072	389
Revenue payable	169,842	154,173
Total current liabilities	728,986	683,167
Long-term debt	1,025,000	924,000

Deferred income taxes	1,539,114	1,459,841
Other liabilities	177,798	163,919
Total liabilities	3,470,898	3,230,927
Commitments and contingencies		
Stockholders’ equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued	—	—
Common stock, $0.01 par value, 200,000,000 shares authorized, 87,033,110 and 87,152,197 shares issued, respectively	870	872
Paid-in capital	1,970,946	1,970,113
Retained earnings	2,174,692	2,050,034
Accumulated other comprehensive income	1,229	1,189
	4,147,737	4,022,208
	$ 7,618,635	$ 7,253,135

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Consolidated Statements of Income and Comprehensive Income

(Unaudited)

	For the Three Months Ended March 31, 2014	2013
	(in thousands, except per share data)	
Revenues:		
Gas sales	$ 170,097	$ 101,121
Oil sales	325,071	257,532
NGL sales	89,957	56,875
Gas gathering and other	12,464	10,727
Gas marketing, net	1,627	101
	599,216	426,356
Costs and expenses:		
Depreciation, depletion and amortization	173,931	136,438
Asset retirement obligation	3,218	2,399
Production	75,141	69,386
Transportation, processing, and other operating	44,248	18,634
Gas gathering and other	8,784	6,156
Taxes other than income	33,621	25,128
General and administrative	20,712	15,577
Stock compensation	3,724	3,605
(Gain) loss on derivative instruments, net	15,735	1,603
Other operating, net	103	2,932
	379,217	281,858
Operating income	219,999	144,498
Other (income) and expense:		
Interest expense	14,042	13,206
Capitalized interest	(7,290)	(9,195)
Other, net	(6,955)	(2,616)
Income before income tax	220,202	143,103
Income tax expense	81,745	53,176
Net income	$ 138,457	$ 89,927
Earnings per share to common stockholders:		
Basic		
Distributed	$ 0.16	$ 0.14
Undistributed	1.43	0.90
	$ 1.59	$ 1.04
Diluted		
Distributed	$ 0.16	$ 0.14

Undistributed	1.43	0.90
	$ 1.59	$ 1.04
Comprehensive income:		
Net income	$ 138,457	$ 89,927
Other comprehensive income:		
Change in fair value of investments, net of tax	40	80
Total comprehensive income	$ 138,497	$ 90,007

See accompanying notes to consolidated financial statements.

CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Three Months Ended March 31, 2014 (in thousands)		2013	
Cash flows from operating activities:				
Net income	$	138,457	$	89,927
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization		173,931		136,438
Asset retirement obligation		3,218		2,399
Deferred income taxes		81,745		53,176
Stock compensation		3,724		3,605
(Gain) loss on derivative instruments		15,735		1,603
Settlements on derivative instruments		(4,787)		726
Changes in non-current assets and liabilities		(4,207)		3,374
Other, net		1,076		1,173
Changes in operating assets and liabilities:				
Receivables, net		(35,529)		(30,576)
Other current assets		(16,772)		9,143
Accounts payable and accrued liabilities		(8,567)		(23,910)
Net cash provided by operating activities		348,024		247,078
Cash flows from investing activities:				
Oil and gas expenditures		(420,040)		(390,669)
Sales of oil and gas and other assets		104		975

Other expenditures		(19,854)		(19,523)
Net cash used by investing activities		(439,790)		(409,217)
Cash flows from financing activities:				
Net bank debt borrowings		101,000		120,000
Dividends paid		(12,143)		(10,356)
Issuance of common stock and other		2,908		1,489
Net cash provided by financing activities		91,765		111,133
Net change in cash and cash equivalents		(1)		(51,006)
Cash and cash equivalents at beginning of period		4,531		69,538
Cash and cash equivalents at end of period	$	4,530	$	18,532

See accompanying notes to consolidated financial statements.

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Notes to Consolidated Financial Statements

March 31, 2014

(Unaudited)

1. Basis of Presentation

The accompanying unaudited financial statements have been prepared by Cimarex Energy Co. ("Cimarex", "we", or "us") 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 2013 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 and as of the dates shown. We have evaluated subsequent events through the date of this filing.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas operations. Accounting rules require us to perform a quarterly ceiling test calculation to test our oil and gas properties for possible impairment. The primary components impacting this calculation are commodity prices, reserve quantities added and produced, overall exploration and development costs, depletion expense, and tax effects. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess would be charged to expense. The ceiling limitation is equal to the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects.

At March 31, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 8% in the value of the ceiling limitation would have resulted in an impairment. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters.

Oil, Gas and NGL sales

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

Under certain contracts, when NGLs are extracted from the gas stream, processors receive as compensation a portion of the sales value from both the residue gas and the NGLs as a processing fee and remit the contractual proceeds to us. Prior to 2014, revenue was recognized net of these processing fees for residue gas and NGLs sold under these contracts as allowed under EITF 00-10 Accounting for Shipping and Handling Fees and Costs. Beginning in 2014, we believe that with the increase in NGL production and the impact of recent changes to these contracts, these processing costs will become more significant in the future. Accordingly, we have changed our policy to record these processing costs with operating costs as allowed under EITF 00-10. As a result, beginning in 2014, our realized prices for sales under these contracts reflect the value of 100% of the residue gas and NGLs yielded by processing, rather than the value associated with the contractual proceeds we received. The related processing fees now are included in "transportation, processing and other" operating costs. The effect of this change

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Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

in the current period was that total revenue was $11.9 million higher with an offsetting increase in total transportation, processing and other costs. There was no impact on operating income. Financial statements for periods prior to 2014 have not been reclassified to reflect this change in accounting treatment as it was impracticable to do so.

Use of Estimates

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 (DD&A), 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 obligations, and the assessment of goodwill. Estimates and judgments are also required in determining allowance 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.

Accounts Receivable, Accounts Payable, and Accrued Liabilities

The components of our receivable accounts, accounts payable, and accrued liabilities are shown below:

(in thousands)	March 31, 2014	December 31, 2013
Receivables, net of allowance		
Trade	$ 76,471	$ 83,070

Oil and gas sales	300,902	265,050
Gas gathering, processing, and marketing	25,586	19,102
Other	324	532
Receivables, net	$ 403,283	$ 367,754
Accounts payable		
Trade	$ 89,117	$ 80,918
Gas gathering, processing, and marketing	51,603	35,192
Accounts payable	$ 140,720	$ 116,110
Accrued liabilities		
Exploration and development	$ 216,785	$ 173,298
Taxes other than income	26,543	27,509
Other	168,024	211,688
Accrued liabilities	$ 411,352	$ 412,495

Subsequent event

In May 2014, we announced our intention to acquire certain Mid-Continent properties for approximately $249 million. Also see litigation in Note 11 and Part II, Item 1 for recent events regarding H.B. Krug, et al versus H&P.

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Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

Recently Issued Accounting Standards

No significant accounting standards applicable to Cimarex have been issued during the quarter ended March 31, 2014.

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.

The following tables summarize our outstanding hedging contracts as of March 31, 2014:

Oil Contracts

				Weighted Average Price		Fair Value
Period	Type	Volume/Day	Index (1)	Floor	Ceiling	(in thousands)
Apr 14 – Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47	$ (2,438)

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

Gas Contracts

Period	Type	Volume/Day	Index (1)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value (in thousands)
Apr 14 – Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$ (2,101)
Apr 14 – Dec 14	Collars	60,000 MMBtu	Perm EP	$ 3.62	$ 4.50	$ (2,530)

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt's Inside FERC. Perm EP refers to El Paso Natural Gas Company, Permian Basin Index as quoted in Platt's Inside FERC.

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 if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

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

We have elected not to account for our derivatives as cash flow hedges. Therefore, we recognize settlements and changes in the assets or liabilities relating to our open derivative contracts in earnings. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows.

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Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

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

	Three Months Ended March 31,	
(in thousands)	2014	2013
Gain (loss) on derivative instruments, net:		
Natural gas contracts	$ (11,882)	$ —
Oil contracts	(3,853)	(1,603)
Gain (loss) on derivative instruments, net	$ (15,735)	$ (1,603)
Gains (losses) from settlement of derivative instruments:		
Natural gas contracts	$ (4,787)	$ —
Oil contracts	—	726
Settlement gains (losses)	$ (4,787)	$ 726

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs. We estimate the fair value with 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 value of our derivative instruments in an asset position includes a measure of counterparty credit risk and the fair value of instruments in a liability position includes a measure of our own non-performance risk. These credit risks are based on current published credit default swap rates.

Due to the volatility of commodity prices, the estimated fair value of our derivative instruments is subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price.

Our derivative instruments are subject to enforceable master netting arrangements, which allow us to offset recognized asset and liability fair value amounts on contracts with the same counterparty. Our policy is to not offset asset and liability positions in our accompanying balance sheets.

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Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

The following table presents the amounts and classifications of our derivative assets and liabilities as of March 31, 2014 and December 31, 2013, as well as the potential effect of netting arrangements on contracts with the same counterparty.

March 31, 2014:			
(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$ 3	$ —
Oil contracts	Current liabilities — Derivative instruments	—	2,441
Natural gas contracts	Current liabilities — Derivative instruments	—	4,631
Total gross amounts presented in accompanying balance sheet		3	7,072
Less: gross amounts not offset in the accompanying balance sheet		(3)	(3)
Net amount:		$ —	$ 7,069

December 31, 2013:			
(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$ 1,805	$ —
Natural gas contracts	Current assets — Derivative instruments	2,463	—
Oil contracts	Current liabilities — Derivative instruments	—	389
Total gross amounts presented in accompanying balance sheet		4,268	389
Less: gross amounts not offset in the accompanying balance sheet		(389)	(389)
Net amount:		$ 3,879	$ —

We are exposed to financial risks associated with our derivative contracts from non-performance by our counterparties. We have mitigated our exposure to any single counterparty by contracting with a number of financial institutions, each of which has a high credit rating and is a member of our bank credit facility. Our member banks do not require us to post collateral for our hedge liability positions. Because some of the member banks have discontinued hedging activities, in the future we may hedge with counterparties outside our bank group to obtain competitive terms and to spread counterparty risk.

3. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). 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 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

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Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

The following tables provide fair value measurement information for certain assets and liabilities as of March 31, 2014 and December 31, 2013:

March 31, 2014: (in thousands)	Carrying Amount	Fair Value
Financial Assets (Liabilities):		
Bank debt	$ (275,000)	$ (275,000)
5.875% Notes due 2022	$ (750,000)	$ (821,250)
Derivative instruments — assets	$ 3	$ 3
Derivative instruments — liabilities	$ (7,072)	$ (7,072)

December 31, 2013: (in thousands)	Carrying Amount	Fair Value
Financial Assets (Liabilities):		
Bank debt	$ (174,000)	$ (174,000)
5.875% Notes due 2022	$ (750,000)	$ (799,988)
Derivative instruments — assets	$ 4,268	$ 4,268
Derivative instruments — liabilities	$ (389)	$ (389)

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

Debt (Level 1)

The fair value of our bank debt at March 31, 2014 and December 31, 2013 was estimated to approximate the carrying amount because the floating rate interest paid on such debt was set for periods of three months or less.

The fair value for our 5.875% fixed rate notes was based on their last traded value before period end.

Derivative Instruments (Level 2)

The fair value of our derivative instruments was estimated using internal discounted cash flow calculations. Cash flows are based on the stated contract prices and current and published forward commodity price curves, adjusted for volatility. The cash flows are risk adjusted relative to non-performance for both our counterparties and our liability positions. Please see Note 2 for further information on the fair value 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 and/or liquid nature of these assets and liabilities.

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.

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Notes to Consolidated Financial Statements (Continued)

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(Unaudited)

We routinely assess the recoverability of all material accounts receivable to determine their collectability. We accrue a reserve to the allowance for doubtful accounts when it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. At March 31, 2014 and December 31, 2013, the allowance for doubtful accounts was $6.0 million.

4. Capital Stock

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At March 31, 2014, there were no shares of preferred stock outstanding. A summary of our common stock activity for the three months ended March 31, 2014 follows:

(in thousands)	
Issued and outstanding as of December 31, 2013	87,152
Restricted shares issued under compensation plans, net of reacquired stock and cancellations	(170)
Option exercises, net of cancellations	51
Issued and outstanding as of March 31, 2014	87,033

Dividends

In February 2014, the Board of Directors declared a cash dividend of $0.16 per share. The dividend is payable on June 2, 2014 to stockholders of record on May 15, 2014. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

5. Stock-based Compensation

Our 2011 Equity Incentive Plan (the 2011 Plan) was approved by stockholders in May 2011 and our previous plan was terminated at that time. Outstanding awards under the previous plan were not impacted. The 2011 Plan provides for grants of stock options, restricted stock, restricted stock units, performance stock and performance stock units. A total of 5.3 million shares of common stock may be issued under the 2011 Plan.

We have recognized non-cash stock-based compensation cost as follows:

	Three Months Ended March 31,	
(in thousands)	2014	2013
Restricted stock	$ 6,451	$ 5,906
Stock options	773	708
	7,224	6,614
Less amounts capitalized to oil and gas properties	(3,500)	(3,009)
Compensation expense	$ 3,724	$ 3,605

Historical amounts may not be representative of future amounts as additional awards may be granted.

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Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

Restricted Stock and Units

During the first quarter of 2014, we granted 2,500 service-based stock awards at a weighted average grant-date fair value of $119.11. No restricted stock awards were granted during the three months ended March 31, 2013.

From time to time performance awards are granted to eligible executives and 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. In accordance with Internal Revenue Code Section 162(m), certain of the amounts awarded may not be deductible for tax purposes. Service-based stock awards granted to other eligible employees and non-employee directors have vesting schedules of three to five years.

Compensation cost for the performance stock awards is based on the grant-date fair value of the award utilizing a Monte Carlo simulation model. Compensation cost for the service-based vesting restricted shares is based upon the grant-date market value of the award. Such costs are recognized ratably over the applicable vesting period.

The following table reflects the non-cash compensation cost related to our restricted stock:

	Three Months Ended March 31,	
(in thousands)	2014	2013
Performance stock awards	$ 2,947	$ 2,685
Service-based stock awards	3,504	3,221

	6,451	5,906
Less amounts capitalized to oil and gas properties	(3,180)	(2,784)
Restricted stock compensation expense	$ 3,271	$ 3,122

Unrecognized compensation cost related to unvested restricted shares at March 31, 2014 was $61.2 million, which we expect to recognize over a weighted average period of approximately 2.4 years.

The following table provides information on restricted stock and unit activity as of March 31, 2014 and changes during the year. A restricted unit held by an employee represents a right to an unrestricted share of common stock upon completion of defined vesting and holding periods. A restricted unit held by a non-employee director represents an election to defer payment of director fees until the time specified by the director in his deferred compensation agreement. The remaining outstanding restricted units shown below represent restricted units held by a non-employee director who has elected to defer payment of common stock represented by the units until termination of his service on the Board of Directors.

	Restricted Stock	Restricted Units
Outstanding as of January 1, 2014	1,863,834	8,838
Vested	(195,664)	N/A
Converted to stock	N/A	—
Granted	2,500	—
Canceled	(80,868)	—
Outstanding as of March 31, 2014	1,589,802	8,838
Vested included in outstanding	N/A	8,838

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

Stock Options

Options granted under our 2011 and previous plans expire seven to ten years from the grant date and have service-based vesting schedules of three to five years. The plans provide 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. No options were granted during the first quarters of 2014 and 2013.

Compensation cost related to stock options is based on the grant-date fair value of the award, recognized ratably over the applicable vesting period. We estimate the fair value 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. We use U.S. Treasury bond rates in effect at the grant date for our risk-free interest rates.

Non-cash compensation cost related to our stock options is reflected in the following table:

	Three Months Ended March 31,	
(in thousands)	2014	2013
Stock option awards	$ 773	$ 708
Less amounts capitalized to oil and gas properties	(320)	(225)
Stock option compensation expense	$ 453	$ 483

As of March 31, 2014, there was $3.5 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost pro rata over a weighted-average period of approximately 1.4 years.

Information about outstanding stock options is summarized below:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (in thousands)
Outstanding as of January 1, 2014	531,016	$ 59.78		
Exercised	(50,751)	$ 57.31		
Forfeited	(7,670)	$ 63.42		
Outstanding as of March 31, 2014	472,595	$ 59.99	5.1 Years	$ 28,075
Exercisable as of March 31, 2014	137,251	$ 50.63	4.3 Years	$ 9,438

The following table provides information regarding the options exercised:

	Three months ended March 31,	
(dollars in thousands)	2014	2013
Number of options exercised	50,751	36,829
Cash received from option exercises	$ 2,909	$ 1,490
Intrinsic value of options exercised	$ 2,650	$ 1,162

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

The following table provides information on non-vested stock option activity as of March 31, 2014 and changes during the year:

	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2014	343,014	$ 21.64	$ 63.81
Forfeited	(7,670)	$ 21.94	$ 63.42
Non-vested as of March 31, 2014	335,344	$ 21.63	$ 63.82

6. Asset Retirement Obligations

We recognize the fair value of liabilities for retirement obligations associated with tangible long-lived assets in the period in which there is a legal obligation associated with the retirement of such assets and the amount can be reasonably estimated. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This liability includes costs related to the plugging and abandonment of wells, the removal of facilities and equipment, and site restorations. 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 included as a component of the DD&A calculations.

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the three months ended March 31, 2014:

(in thousands)	
Asset retirement obligation at January 1, 2014	$ 154,026
Liabilities incurred	1,893
Liability settlements and disposals	(2,229)
Accretion expense	1,849
Revisions of estimated liabilities	7,127
Asset retirement obligation at March 31, 2014	162,666
Less current obligation	(16,719)
Long-term asset retirement obligation	$ 145,947

7. Long-Term Debt

Debt at March 31, 2014 and December 31, 2013 consisted of the following:

(in thousands)	March 31, 2014	December 31, 2013
Bank debt	$ 275,000	$ 174,000
5.875% Senior Notes due 2022	750,000	750,000
Total long-term debt	$ 1,025,000	$ 924,000

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

Bank Debt

We have a five-year senior unsecured revolving credit facility (Credit Facility), which matures July 14, 2016. The Credit Facility provides for a borrowing base of $2.25 billion with aggregate commitments of $1 billion from our lenders. The borrowing base under the Credit Facility is determined at the discretion of the lenders based on the value of our proved reserves. In May 2014, we amended the Credit Facility to extend the maturity date to July 14, 2018 and lower the margins applicable to loans and commitments. The amendment also set our borrowing base at $2.5 billion until the next regular annual redetermination date scheduled for April 15, 2015. Our aggregate commitments remain unchanged at $1 billion.

As of March 31, 2014, we had $275 million of bank debt outstanding at a weighted average interest rate of 1.986%. We also had letters of credit outstanding under the Credit Facility of $2.5 million, leaving an unused borrowing availability of $722.5 million.

At our option, borrowings under the Credit Facility, as amended in May 2014, may bear interest at either (a) LIBOR plus 1.5-2.25%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.5-1.25%, based on our leverage ratio.

The Credit Facility also has financial covenants that include the maintenance of current assets (including unused bank commitments) to current liabilities of greater than 1.0. We also must maintain a leverage ratio of total debt to earnings before interest expense, income taxes and non-cash items (such as depreciation, depletion and amortization expense, unrealized gains and losses on commodity derivatives, ceiling test write-downs, and goodwill impairments) of not more than 3.5. Other covenants could limit our ability to incur additional indebtedness, pay dividends, repurchase our common stock, or sell assets. As of March 31, 2014, we were in compliance with all of the financial and non-financial covenants.

5.875% Notes due 2022

In April 2012, we issued $750 million of 5.875% senior notes due May 1, 2022, with interest payable semiannually in May and November. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions. We may redeem the notes in whole or in part, at any time on or after May 1, 2017, at redemption prices of 102.938% of the principal amount as of May 1, 2017, declining to 100% on May 1, 2020 and thereafter.

8. Income Taxes

The components of our provision for income taxes are as follows:

	Three months ended March 31,	
(in thousands)	2014	2013
Current benefit	$ —	$ —
Deferred taxes	81,745	53,176
	$ 81,745	$ 53,176

At December 31, 2013, we had a U.S. net tax operating loss carryforward of approximately $605.4 million, which would expire in tax years 2031 through 2033. We believe that the carryforward will be utilized before it expires. The amount of U.S. net tax operating loss carryforward that will be recorded to equity when utilized to reduce taxes payable is $56.4 million. We also had an alternative minimum tax credit carryforward of approximately $4.1 million.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

At March 31, 2014, we had no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2009-2012 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 to examination for the 2009-2012 tax years.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and non-deductible expenses. The effective income tax rates for the three months ended March 31, 2014 and March 31, 2013 were 37.1% and 37.2%, respectively.

9. Supplemental Disclosure of Cash Flow Information:

	Three months ended March 31,	
(in thousands)	2014	2013
Cash paid during the period for:		
Interest expense (including capitalized amounts)	$ 2,095	$ 1,018
Interest capitalized	$ 1,088	$ 709
Income taxes	$ 1	$ 55
Cash received for income taxes	$ 209	$ 15

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

10. Earnings per Share

The calculations of basic and diluted net earnings per common share under the two-class method are presented below:

(in thousands, except per share data)	Three months ended March 31, 2014	2013
Basic:		
Net income	$ 138,457	$ 89,927
Participating securities’ share in earnings	(2,287)	(1,385)
Net income applicable to common stockholders	$ 136,170	$ 88,542
Diluted:		
Net income	$ 138,457	$ 89,927
Participating securities’ share in earnings	(2,284)	(1,383)
Net income applicable to common stockholders	$ 136,173	$ 88,544
Shares:		
Basic shares outstanding	85,443	84,920
Incremental shares from assumed exercise of stock options	136	96
Fully diluted common stock	85,579	85,016
Excluded (1)	1	156
Earnings per share to common stockholders:		
Basic	$ 1.59	$ 1.04
Diluted	$ 1.59	$ 1.04

(1) Inclusion of certain outstanding stock options would have an anti-dilutive effect.

11. Commitments and Contingencies

Commitments

We have commitments of $199.5 million to finish drilling and completing wells in progress at March 31, 2014.

In New Mexico and Texas, we are constructing gathering facilities and pipelines. At March 31, 2014, we had commitments of $11.1 million relating to these construction projects.

At March 31, 2014, we had firm sales contracts to deliver approximately 25.8 Bcf of natural gas over the next 12 months. If this gas is not delivered, our financial commitment would be approximately $110.2 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 current proved reserves and production levels.

We have other various transportation and delivery commitments in the normal course of business, which approximate $3.3 million over the next four years.

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements (Continued)

March 31, 2014

(Unaudited)

We have various commitments for office space and equipment under operating lease arrangements totaling $129.6 million for the next five years and beyond.

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

Litigation

In the normal course of business, we have various litigation matters. We assess the probability of estimable amounts related to litigation matters in accordance with guidance established by the FASB and adjust our accruals accordingly. Though some of the related claims may be significant, we believe the resolution of them, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations after consideration of current accruals.

H.B. Krug, et al versus H&P

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the H.B. Krug, et al. v. Helmerich & Payne, Inc. (H&P) case. This lawsuit originally was filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage and other related issues. Pursuant to the 2002 spin-off of H&P, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. In 2008, we recorded a litigation expense of $119.6 million plus additional post-judgment interest and costs after the trial court entered a final judgment for these amounts.

On December 10, 2013 the Oklahoma Supreme Court reversed the trial court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. In light of the Oklahoma Supreme Court's ruling, on December 31, 2013, we reduced previously recognized litigation expense and the associated long-term liability by $142.8 million.

On March 14, 2014, after denying the Plaintiffs' Petition for Rehearing, the Oklahoma Supreme Court remanded the matter back to the trial court. On March 31, 2014, the trial court entered a final Judgment on Remand for damages of $3.65 million and post-judgment interest and on April 1, 2014, Cimarex wired $15.8 million to Plaintiff's trust account in satisfaction of the judgment plus post-judgment interest and in satisfaction of the payment in lieu of bond. The only issues that now remain are what amounts, if any, Plaintiffs are entitled to receive regarding prejudgment interest, attorney's fees and costs. On April 4, 2014, Cimarex filed a motion asking the trial court to rule that the Plaintiffs are not entitled to any attorney's fees or prejudgment interest. The outcome of these remaining issues cannot be determined at this time. Our current assessments and estimates likely will change in the future as a result of subsequent legal proceedings both in the trial court and on appeal.

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

OVERVIEW

Cimarex is an independent oil and gas exploration and production company. Our operations are entirely located in the United States, mainly in Oklahoma, Texas and New Mexico.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our stock holders through a diversified drilling portfolio. Our strategy centers on maximizing cash flow from producing properties and profitably reinvesting that cash flow in exploration and development. We occasionally consider property acquisitions and mergers to enhance our competitive position.

In order to achieve a consistent rate of growth and mitigate risk, we have historically maintained a portfolio of exploration and development projects targeting both oil and gas. We seek geologic and geographic diversification by operating in multiple basins. In recent years, we have shifted our capital expenditures to oil and liquids-rich gas projects because of strong oil prices relative to gas prices. We deal with volatility in commodity prices by maintaining flexibility in our capital investment program. In addition, we periodically hedge a portion of our oil and gas production to mitigate our potential exposure to price declines and the corresponding negative impact on cash flow available for investment.

Our operations currently are focused in two main areas: the Permian Basin and the Mid-Continent region. Our Permian Basin region encompasses west Texas and southeast New Mexico. The Mid-Continent region consists of Oklahoma, the Texas Panhandle, and southwest Kansas.

Growth is generally funded with cash flow provided by operating activities together with bank borrowings, sales of non-strategic assets and occasional public financing. Conservative use of leverage and maintaining a strong balance sheet have long been part of our financial strategy. We have a long track record of profitable growth.

First quarter 2014 summary of operating and financial results:

- Average daily production was 740.4 MMcfe/d.

- Oil production grew 18%, gas production was up by 7% and NGL volumes increased by 16%.

- Oil, gas and NGL sales for the first quarter of 2014 were $585.1 million, 41% higher than a year earlier.

- Net income increased 54% to $138.5 million, or $1.59 per diluted share.

- Cash flow provided by operating activities was $348.0 million versus $247.1 million for the same period of 2013.

- Exploration and development expenditures for the quarter totaled $467.0 million.

- Total debt at March 31, 2014 was $1.025 billion, up $101 million from year-end 2013.

Revenues

Almost all of our revenues are derived from the sales of oil, gas and NGL production. Our revenue, profitability and future growth are highly dependent on the commodity prices we receive. Compared to 2013, our first quarter average realized gas price increased by 57%. Our average realized oil price increased by 7% and our

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average realized NGL price increased 36%. Prices we receive are determined by prevailing market conditions. Regional and worldwide economic and geopolitical activity, weather and other factors influence market conditions, which often result in significant volatility in commodity prices.

Prior to 2014, our average realized prices for gas and NGLs were net of certain processing fees. Beginning in 2014, these fees are no longer included in these prices, thus positively impacting gas by $0.09 per Mcf and NGLs by $4.02 per barrel. (See Note 1, Oil, Gas and NGL Sales, to the Consolidated Financial Statements in this report for additional information.)

Our realized prices do not include settlements of our commodity hedging contracts.

	Three months ended March 31,	
	2014	2013
Oil Prices:		
Average WTI Cushing price ($/Bbl)	$ 98.68	$ 94.38
Average realized sales price ($/Bbl)	$ 92.22	$ 86.31
Gas Prices:		
Average Henry Hub price ($/Mcf)	$ 4.95	$ 3.34
Average realized sales price ($/Mcf)	$ 5.32	$ 3.38
NGL Prices:		
Average realized sales price ($/Bbl)	$ 39.94	$ 29.31

On an energy equivalent basis, 52% of our aggregate 2014 production was crude oil and NGLs. A $1.00 per barrel change in our average realized sales price would have resulted in a $5.8 million change in our combined oil and NGL revenues. Similarly, 48% of our production was natural gas. A $0.10 per Mcf change in our average realized gas sales price would have resulted in a $3.2 million change in our gas revenues.

See RESULTS OF OPERATIONS below for a discussion of the impact changes in realized prices had on our 2014 revenues.

Production and other operating expenses

Costs associated with producing oil and gas are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production and some are a function of the number of wells we own. At the end of 2013, we owned interests in 12,079 gross wells.

Production expense generally consists of costs for labor, equipment, maintenance, salt water disposal, compression, power, treating and miscellaneous other costs. Production expense also includes well workover activity necessary to maintain production from existing wells.

Transportation, processing and other operating costs include processing costs and expenditures to prepare and transport production from the wellhead to a specified sales point. These costs vary by region and will fluctuate with increases or decreases in production volumes and changes in fuel and compression costs.

Depreciation, depletion and amortization (DD&A) of our producing properties is computed using the units-of-production method. The economic life of each producing well depends upon the estimated proved reserves for that well, which in turn depend upon the assumed price for future sales of production. Therefore, fluctuations in oil and gas prices will impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense. Conversely, lower prices generally have the effect of decreasing reserves, which increases depletion expense. The cost of replacing production also impacts our

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DD&A rate. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, and reclassifications of properties from unproved to proved will impact depletion expense.

We use the full cost method of accounting for our oil and gas properties. Accounting rules require us to perform a quarterly ceiling test calculation to test our oil and gas properties for possible impairment. The primary components impacting this analysis are commodity prices, reserve quantities added and produced, overall exploration and development costs, depletion expense, and tax effects. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess would be expensed. The ceiling limitation is equal to the sum of (a) the present value discounted at 10% of estimated future net cash flows from proved reserves, (b) the cost of properties not being amortized, (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and (d) all related tax effects.

At March 31, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 8% in the value of the ceiling limitation would have resulted in an impairment. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur a full cost ceiling impairment related to our oil and gas properties in future quarters. An impairment charge would have no effect on liquidity or our capital resources, but it would adversely affect our results of operations in the period incurred.

General and administrative (G&A) 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. Our G&A expense is reported net of amounts reimbursed to us by working interest owners of the oil and gas properties we operate and net of amounts capitalized pursuant to the full cost method of accounting.

See RESULTS OF OPERATIONS below for a discussion of changes in production and other operating expenses.

Derivative Instruments/Hedging

We periodically enter into derivative instruments to mitigate a portion of our potential exposure to a decline in oil and/or gas 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.

During the first three months of 2014, we had hedges covering 31% of our oil production and 36% of our gas production. Through March 31, 2014, we paid net cash settlements of $4.8 million on our gas contracts and no cash settlements on our oil contracts.

The following tables summarize our outstanding hedging contracts as of March 31, 2014:

Oil Contracts

				Weighted Average Price	
Period	Type	Volume/Day	Index (1)	Floor	Ceiling
Apr 14 – Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

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Gas Contracts

				Weighted Average Price	
Period	Type	Volume/Day	Index (1)	Floor	Ceiling
Apr 14 – Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57
Apr 14 – Dec 14	Collars	60,000 MMBtu	Perm EP	$ 3.62	$ 4.50

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt's Inside FERC. Perm EP refers to El Paso Natural Gas Company, Permian Basin Index as quoted in Platt's Inside FERC.

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

Since 2009, we have chosen not to apply hedge accounting treatment to our derivative contracts. As a result, 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 the discussion of our net gain/loss on hedging activities below, in RESULTS OF OPERATIONS. Also, see Note 2 to the Consolidated Financial Statements and Item 3 in this report for additional information regarding our derivative instruments.

RESULTS OF OPERATIONS

Quarter Ended March 31, 2014 vs. March 31, 2013

Net income for the first quarter of 2014 was $138.5 million ($1.59 per diluted share), up 54% from $89.9 million ($1.04 per diluted share) for the same period of 2013. The increase in 2014 net income was primarily a result of higher production revenue from increased production volumes and higher realized commodity prices. The increase in production revenue was partially offset by higher operating expenses and income taxes compared to the first quarter of 2013. These changes are discussed further in the analysis that follows.

Production Revenue			Percent Change Between 2014 / 2013	Price/Volume Change		
(in thousands or as indicated)	2014	2013		Price	Volume	Total
For the Three Months Ended March 31,						
Oil sales	$ 325,071	$ 257,532	26 %	$ 20,833	$ 46,706	$ 67,539
Gas sales	170,097	101,121	68 %	62,028	6,948	68,976
NGL sales	89,957	56,875	58 %	23,939	9,143	33,082
	$ 585,125	$ 415,528	41 %	$ 106,800	$ 62,797	$ 169,597

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	For the Three Months Ended March 31,		Percent Change Between 2014 / 2013
	2014	2013	
Total oil volume — thousand barrels	3,525	2,984	18 %
Oil volume — barrels per day	39,168	33,154	18 %
Average oil price — per barrel	$ 92.22	$ 86.31	7 %
Total gas volume — MMcf	31,973	29,952	7 %
Gas volume — MMcf per day	355.3	332.8	7 %
Average gas price — per Mcf	$ 5.32	$ 3.38	57 %
Total NGL volume — thousand barrels	2,252	1,941	16 %
NGL volume — barrels per day	25,028	21,562	16 %
Average NGL price — per barrel	$ 39.94	$ 29.31	36 %
Total equivalent production volumes — MMcfe per day	740.4	661.1	12 %

Revenue from our first quarter 2014 production totaled $585.1 million compared to $415.5 million for the same quarter of last year. Increased production volumes together with higher realized commodity prices resulted in the year-over-year improvement.

Our first-quarter 2014 aggregate production volumes reached a record 740.4 MMcfe per day, up 12% from 661.1 MMcfe per day for the first quarter of 2013. The growth in production resulted from our successful drilling programs in the Permian Basin and Mid-Continent region.

Oil production for the first quarter of 2014 averaged 39,168 Bbl/d, up 18% from 33,154 Bbl/d in 2013. The growth in 2014 volume provided an additional $46.7 million of oil revenue.

First-quarter 2014 gas production averaged 355 MMcf/d, compared to 333 MMcf/d in 2013. The 7% year-over-year increase resulted in additional revenue of $6.9 million.

During the first quarter of 2014, our average NGL production volumes of 25,028 Bbl/d were 16% greater than 21,562 Bbl/d for 2013 and contributed an additional $9.1 million of revenue.

Realized oil prices during the first quarter of 2014 averaged $92.22 per barrel, an increase of 7% from $86.31 per barrel received in the same period of 2013. The higher price in 2014 contributed $20.8 million of additional oil revenue.

Our average realized gas price for the first quarter of 2014 improved by 57% to $5.32 per Mcf, compared to $3.38 per Mcf in 2013. The 2014 increase in price provided additional revenue of $62.0 million. As noted above under Revenues, beginning in 2014, our realized price for gas no longer includes certain processing fees, thus positively impacting revenue by $2.9 million ($0.09 per Mcf).

In the first three months of 2014, our realized price for NGLs averaged $39.94 per barrel, which was 36% higher than the average realized price of $29.31 per barrel in the 2013 period. The higher price in 2014 accounted for additional revenues of $23.9 million. As noted above under Revenues, beginning in 2014, our realized price for NGLs no longer includes certain processing fees, thus positively impacting revenue by $9.0 million ($4.02 per barrel).

We sometimes transport, process and market third-party gas that is associated with our gas. The table below reflects our pre-tax operating margin (revenues less direct expenses) for third-party gas gathering and processing as well as the marketing margin (revenues less purchases) for marketing third-party gas.

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	For the Three Months Ended March 31,	
	2014	2013
Gas Gathering and Marketing (in thousands):		
Gas gathering and other revenues	$ 12,464	$ 10,727
Gas gathering and other costs	(8,784)	(6,156)
Gas gathering and other margin	$ 3,680	$ 4,571
Gas marketing revenues, net of related costs	$ 1,627	$ 101

Fluctuations in net margins from gas gathering and gas marketing activities are a function of increases and decreases in volumes and prices associated with third-party gas.

In the first quarter of 2014, our total operating costs and expenses (not including gas gathering and marketing costs, or income tax expense) were $370.4 million, up 34% compared to $275.7 million in the same period of 2013. Analyses of the year-over-year differences are discussed below.

	For the Three Months Ended March 31,		Variance Between 2014 /	Per Mcfe	
	2014	2013	2013	2014	2013
Operating costs and expenses (in thousands, except per Mcfe):					
Depreciation, depletion and amortization	$ 173,931	$ 136,438	$ 37,493	$ 2.61	$ 2.29
Asset retirement obligation	3,218	2,399	819	$ 0.05	$ 0.04
Production	75,141	69,386	5,755	$ 1.13	$ 1.17
Transportation, processing and other operating	44,248	18,634	25,614	$ 0.66	$ 0.31
Taxes other than income	33,621	25,128	8,493	$ 0.51	$ 0.42
General and administrative	20,712	15,577	5,135	$ 0.31	$ 0.26
Stock compensation	3,724	3,605	119	$ 0.06	$ 0.06
(Gain) loss on derivative instruments, net	15,735	1,603	14,132	N/A	N/A
Other operating, net	103	2,932	(2,829)	N/A	N/A
	$ 370,433	$ 275,702	$ 94,731		

Our first quarter 2014 DD&A expense of $173.9 million was 27% higher than the same period of 2013 and accounted for 40% of the total quarter-over-quarter increase in costs and expenses. On a unit of production basis, first quarter 2014 DD&A increased by $0.32 (14%) to $2.61 per Mcfe. About 40% of the 2014 increase in DD&A was attributable to our higher production volumes. The rest of the increase was a result of a higher DD&A rate. Our DD&A rate has increased because the per unit cost of adding new proved reserves has exceeded the net remaining book basis of proved reserves added in prior years. We expect our annual average DD&A rate to increase modestly during 2014 compared to 2013.

Production costs consist of lease operating expense and workover expense as follows:

	For the Three Months Ended March 31,		Variance Between 2014 /	Per Mcfe	
(in thousands, except per Mcfe)	2014	2013	2013	2014	2013
Lease operating expense	$ 61,078	$ 53,146	$ 7,932	$ 0.92	$ 0.89
Workover expense	14,063	16,240	(2,177)	$ 0.21	$ 0.28
	$ 75,141	$ 69,386	$ 5,755	$ 1.13	$ 1.17

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Lease operating expense in the first quarter of 2014 increased by 15% compared to 2013. As we continued to put new wells on production, we had increased costs for compression, rental equipment, chemical treating and fuel. We have also had year-over-year increased costs for site maintenance, road repairs and labor.

Our workover expense for the first quarter of 2014 was 13% lower than the same period of 2013. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period. The decrease in 2014 was primarily a result of less workover activity in the Permian Basin.

Transportation, processing and other operating costs for the first quarter of 2014 increased significantly compared to the same period of 2013. In general, these costs will vary by product type and region. Increases or decreases in sales and processing volumes, compression charges and fuel costs also have an impact. Approximately $13.7 million (53%) of the quarter-over-quarter increase resulted from new contracts with higher fees, more wells on compression and we experienced higher fuel costs related to commodity price increases in 2014. The remainder of the increase ($11.9 million) relates to the inclusion of certain processing fees which in previous periods were treated as a reduction in realized sales prices for residue gas and NGLs. See Note 1, Oil, Gas and NGL Sales, to the Consolidated Financial Statements of this report for additional information.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based severance taxes are our largest component of these taxes. During the first three months of 2014, our taxes increased by 34% compared to the same period of 2013. The increase is primarily due to increased severance taxes on higher production volumes.

General and administrative (G&A) costs were as follows:

	For the Three Months Ended March 31,		Variance Between 2014 /
(in thousands)	2014	2013	2013
G&A capitalized to oil & gas properties	$ 17,175	$ 18,679	$ (1,504)
G&A expense	20,712	15,577	5,135
	$ 37,887	$ 34,256	$ 3,631
G&A expense per Mcfe	$ 0.31	$ 0.26	$ 0.05

Our first quarter 2014 G&A costs of $37.9 million increased 11% compared to 2013. The increase was mainly attributable to higher salaries and benefits due to more employees in 2014 as well as higher rent related to new office facilities.

Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock and stock option awards, net of amounts capitalized. We have recognized non-cash stock-based compensation cost as follows:

	For the Three Months Ended March 31,		Variance Between 2014 / 2013
(in thousands)	2014	2013	
Performance-based restricted stock awards	$ 2,947	$ 2,685	$ 262
Service-based restricted stock awards	3,504	3,221	283
Restricted stock	6,451	5,906	545
Stock option awards	773	708	65
Total stock compensation	7,224	6,614	610
Less amounts capitalized to oil & gas properties	(3,500)	(3,009)	(491)
Stock compensation	$ 3,724	$ 3,605	$ 119

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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 5 to the Consolidated Financial Statements for further discussion regarding our stock-based compensation.

We have not elected hedge accounting treatment for our derivative instruments. Therefore, we recognize settlements and changes in the assets or liabilities relating to our open derivative contracts in earnings. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows.

Gains and losses on our derivative contracts are a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments. See Item 3 and Note 2 to the Consolidated Financial Statements in this report for further details regarding our derivative instruments.

The following table summarizes the net (gains) and losses from settlements and changes in fair value of our derivative contracts.

	For the Three Months Ended March 31,	
(in thousands)	2014	2013
(Gain) loss on derivative instruments, net:		
Natural gas contracts	$ 11,882	$ —
Oil contracts	3,853	1,603
(Gain) loss on derivative instruments, net	$ 15,735	$ 1,603
Settlement (gains) losses:		
Natural gas contracts	$ 4,787	$ —
Oil contracts	—	(726)
Settlement (gains) losses	$ 4,787	$ (726)

Other operating, net consists of costs related to various legal matters. See Note 11 to the Consolidated Financial Statements and Part II, Item 1, in this report for further information regarding litigation matters and recent events regarding H.B. Krug, et al versus H&P.

Other (income) and expense

(in thousands)	For the Three Months Ended March 31, 2014	2013	Variance Between 2014 / 2013
Interest expense	$ 14,042	$ 13,206	$ 836
Capitalized interest	(7,290)	(9,195)	1,905
Other, net	(6,955)	(2,616)	(4,339)
	$ (203)	$ 1,395	$ (1,598)

Interest expense includes interest on debt and amortization of financing costs. Our first quarter 2014 interest expense increased 6% compared to the first quarter of 2013. The increase was primarily a result of having higher outstanding bank debt in the first quarter of 2014.

We capitalize interest on non-producing leasehold costs, the costs of drilling and completing wells and constructing qualified assets. Period-over-period costs will fluctuate based on the current rate of interest and the amount of costs on which interest is calculated. Capitalized interest quarter-over-quarter declined 21% because of a lower average interest rate in 2014 applied to lower capitalized expenditures.

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Components of other, net consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. The $4.3 million increase in other, net (income) for the first quarter of 2014 versus 2013 is mainly due to higher gains from sales of oil and gas well equipment and supplies.

Income Tax Expense

The components of our provision for income taxes are as follows:

	Three months ended March 31,	
(in thousands)	2014	2013
Current benefit	$ —	$ —
Deferred taxes	81,745	53,176
	$ 81,745	$ 53,176
Combined Federal and State effective income tax rate	37.1 %	37.2 %

Our combined Federal and state effective tax rates differ from the statutory rate of 35% primarily due to state income taxes and non-deductible expenses. See Note 8 to the Consolidated Financial Statements of this report for additional information regarding our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our liquidity is highly dependent on the prices we receive for the oil, gas and NGLs we produce. Prices received for production heavily influence our revenue, cash flow, profitability, access to capital and future rate of growth.

In the first quarter of 2014 our average realized price for natural gas was $5.32 per Mcf, an increase of 57% over the average realized price of $3.38 for the first quarter of 2013. Average realized prices per barrel for oil and NGL in the first quarter of 2014 increased 7% and 36%, respectively, compared to the same period of 2013. The quarter-over-quarter increases in realized prices contributed $106.8 million of additional revenue for the first quarter of 2014.

Commodity prices are market driven and future prices will likely continue to fluctuate due to supply and demand factors, seasonality and other geopolitical and economic factors. We deal with volatility in commodity prices by maintaining flexibility in our capital investment program. In addition, we periodically hedge a portion of our oil and/or gas production to mitigate our potential exposure to price declines and the corresponding negative impact on cash flow available for investment.

Based on current economic conditions, our 2014 exploration and development (E&D) capital expenditures are estimated to be $1.9 billion. In May 2014, we announced our intention to acquire certain Mid-Continent properties for approximately $249 million. Our total 2014 capital expenditures are now estimated to be approximately $2.2 billion. We expect our capital expenditures to be funded mostly with cash flow provided by operating activities and long-term debt. The timing of capital expenditures and the receipt of cash flows do not necessarily match, causing us to borrow and repay funds under our bank credit facility throughout the year. Occasional sales of non-core assets may also be used to supplement funding of capital expenditures.

At March 31, 2014, our long-term debt totaled $1.025 billion and consisted of $750 million of 5.875% senior notes and $275 million of borrowings under our bank credit facility. We also had letters of credit outstanding under our bank credit facility of $2.5 million, leaving an unused borrowing availability of $722.5 million. Our debt

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to total capitalization at March 31, 2014 was 20%. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $1.025 billion divided by long-term debt of $1.025 million plus stockholders' equity of $4.147 billion. Management believes that this non-GAAP measure is useful information as it is a common statistic used in the investment community.

We believe that our operating cash flow and other capital resources will be adequate to meet our needs for planned capital expenditures, working capital, debt servicing and dividend payments in 2014 and beyond.

Analysis of Cash Flow Changes

Cash flow provided by operating activities for the first quarter of 2014 was $348.0 million compared to $247.1 million for the same period of 2013. The $100.9 million (41%) increase was a result of increased revenue from higher realized commodity prices and increased production volumes, which were partially offset by higher production related operating expenses.

During the first quarter of 2014, net cash flow used for investing activities was $439.8 million, up $30.6 million (7%) from $409.2 million for the first quarter of 2013.

In the first three months of 2014, net cash flow used for investing activities exceeded net cash flow provided by operating activities by $91.8 million. The shortfall was made up by net cash inflows from bank borrowings of $101.0 million. Bank borrowings and proceeds from issuance of common stock were partially offset by dividend payments, resulting in net cash provided by financing activities of $91.8 million.

For the first quarter of 2013, net cash flow used for investing activities was greater than net cash flow provided by operating activities by $162.1 million. Net bank borrowings of $120.0 million plus proceeds of $1.5 million from issuance of common stock from the exercise of stock options, less dividend payments of $10.4 million provided $111.1 million of net cash flow from financing activities. The remaining shortfall was made up from the use of cash and cash equivalents of $51.0 million.

Reconciliation of Adjusted Cash Flow from Operations

	Three months ended March 31,	
(in thousands)	2014	2013
Net cash provided by operating activities	$ 348,024	$ 247,078
Change in operating assets and liabilities	60,868	45,343
Adjusted cash flow from operations	$ 408,892	$ 292,421

Management believes that the non-GAAP measure of adjusted cash flow from operations is useful information for investors. It is accepted by the investment community as a means of measuring a company's ability to fund its capital program without reflecting fluctuations caused by changes in current assets and liabilities (which are included in the GAAP measure of cash flow from operating activities). It is also used by professional research analysts in providing investment recommendations pertaining to companies in the oil and gas exploration and production industry.

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Capital Expenditures

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

(in thousands)	Three months ended March 31, 2014	2013
Acquisitions:		
Proved	$ —	$ —
Unproved	—	250
	—	250
Exploration and development:		
Land and seismic	65,325	31,310
Exploration and development	401,702	377,297
	467,027	408,607
Sales proceeds:		
Proved	—	(818)
Unproved	—	(81)
	—	(899)
	$ 467,027	$ 407,958

Capital expenditures in the table above are presented on an accrual basis. Oil and gas expenditures and sales in the Condensed Consolidated Statements of Cash Flows in this report reflect capital expenditures on a cash basis, when payments are made.

Our exploration and development expenditures of $467.0 million during the first quarter of 2014 were $58.4 million (14%) higher than the $408.6 million of expenditures during the 2013 period. About 69% of our 2014 expenditures were for Permian Basin projects and almost all of the remainder was invested in projects in the Mid-Continent.

The following table reflects wells drilled by region:

	Three months ended March 31, 2014	2013
Gross wells		
Permian Basin	34	35
Mid-Continent	39	52
Other	1	—
	74	87
Net wells		
Permian Basin	21	27
Mid-Continent	14	20
Other	1	—
	36	47
% Gross wells completed as producers	99 %	100 %

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As of March 31, 2014, we had 63 gross wells awaiting completion: 40 Mid-Continent and 23 Permian Basin.

Our 2014 E&D capital expenditures are expected to be approximately $1.9 billion, most of which will again be directed towards drilling oil and liquids-rich gas wells in the Permian Basin and Mid-Continent region. At March 31, 2014 we had 20 operated rigs running: 17 in the Permian Basin and 3 in the Mid-Continent region.

We regularly review our E&D capital expenditures and will adjust our activity based on changes in commodity prices, service costs and drilling success. In addition, we actively evaluate acquisitions, particularly in our core area of operations. We also evaluate our non-core property holdings for potential divestures.

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. 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

Future cash flows and the availability of financing are subject to a number of variables including success in finding and producing new reserves, production from existing wells and realized commodity prices. To meet capital and liquidity requirements, we rely on certain resources, including cash flows from operating activities, bank borrowings, and access to capital markets. We routinely use our bank credit facility to finance our working capital needs.

During the first quarter of 2014, our total assets increased by $365.5 million to $7.6 billion, up from $7.2 billion at December 31, 2013. The increase resulted mostly from a $309.0 million increase in our net oil and gas properties and $45.5 million increase in our current assets. $35.9 million of the increase in current assets was due to increased oil and gas sales receivables resulting from increased commodity prices and production volumes.

Total liabilities at March 31, 2014 increased to $3.4 billion, up $240.0 million from $3.2 billion at year-end 2013. The increase resulted from an additional $101.0 million in bank debt, an increase in non-current deferred income taxes of $79.3 million and an increase in current liabilities of $45.8 million. $43.5 million of the increase in current liabilities related to increased accrued exploration and development costs.

Our stockholders' equity totaled $4.1 billion at March 31, 2014, up $125.5 million from $4.0 billion at December 31, 2013. The increase resulted mainly from net income of $138.5 million less dividends of $13.8 million.

Dividends

A quarterly cash dividend has been paid to stockholders every quarter since the first quarter of 2006. In February 2014, the quarterly dividend was increased to $0.16 per share from $0.14 per share. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

Working Capital Analysis

Our working capital balance fluctuates primarily as a result of our exploration and development activities, realized commodity prices, and changes related to our operating activities. Working capital is also impacted by changes in our oil and gas well equipment and supplies, our current tax provision and changes in the fair value of our outstanding derivative instruments.

At March 31, 2014, our working capital deficit of $214.3 million was flat compared to a deficit of $214.0 million at December 31, 2013.

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Working capital increases consisted of the following:

· Operations-related accounts receivable increased by $35.7 million.

· Oil and gas well equipment and supplies increased by $17.6 million.

· Operations related accounts payable and accrued liabilities decreased by $4.4 million.

Working capital increases were offset by:

· Accrued liabilities related to our E&D expenditures increased by $43.5 million.

· The net fair value of our derivative instruments declined by $10.9 million.

· Current deferred income taxes decreased by $2.7 million.

Accounts receivable are a major component of our working capital and include a diverse group of companies comprised of major energy companies, pipeline companies, local distribution companies and other end-users. The collection of receivables during the periods presented has been timely. Historically, losses associated with uncollectible receivables have not been significant.

Long-term Debt

Long-term debt at March 31, 2014 and December 31, 2013, which is guaranteed by our subsidiaries, consisted of the following:

March 31,

(in thousands)	2014	December 31, 2013
Bank debt	$ 275,000	$ 174,000
5.875% Senior Notes due 2022	750,000	750,000
Total long-term debt	$ 1,025,000	$ 924,000

Bank Debt

We have a five-year senior unsecured revolving credit facility (Credit Facility), which matures July 14, 2016. The Credit Facility provides for a borrowing base of $2.25 billion with aggregate commitments of $1 billion from our lenders. The borrowing base under the Credit Facility is determined at the discretion of the lenders based on the value of our proved reserves. In May 2014, we amended the Credit Facility to extend the maturity date to July 14, 2018 and lower the margins applicable to loans and commitments. The amendment also set our borrowing base at $2.5 billion until the next regular annual redetermination date scheduled for April 15, 2015. Our aggregate commitments remain unchanged at $1 billion.

As of March 31, 2014, we had $275.0 million of bank debt outstanding at a weighted average interest rate of 1.986%. We also had letters of credit outstanding of $2.5 million, leaving an unused borrowing availability of $722.5 million. During the first quarter of 2014, we had average daily bank debt outstanding of $259.8 million, compared to $51.8 million for the same period in 2013. Our highest amount of bank borrowings outstanding during the first three months of 2014 was $365.0 million, occurring in March. During the same period of 2013, the highest amount of outstanding bank borrowings was $178 million, also occurring in March.

At our option, borrowings under the Credit Facility, as amended in May 2014, may bear interest at either (a) LIBOR plus 1.5-2.25%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.5-1.25%, based on our leverage ratio.

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The Credit Facility has a number of financial and non-financial covenants of which we were in compliance with at March 31, 2014. See Note 7 to the Consolidated Financial Statements in this report for further information.

5.875% Notes due 2022

In April 2012, we issued $750 million of 5.875% senior notes due May 1, 2022, with interest payable semiannually in May and November. The notes were sold to the public at par. The notes are governed by an indenture containing certain covenants, events of default and other restrictive provisions. We may redeem the notes in whole or in part, at any time on or after May 1, 2017, at redemption prices of 102.938% of the principal amount as of May 1, 2017, declining to 100% on May 1, 2020 and thereafter.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of March 31, 2014, our material off-balance sheet arrangements included operating lease agreements, which are customary in the oil and gas industry and are included in the table below.

Contractual Obligations and Material Commitments

At March 31, 2014, we had contractual obligations and material commitments as follows:

	Payments Due by Period				
Contractual obligations:		1 Year or	2 - 3	4 - 5	More than
(in thousands)	Total	Less	Years	Years	5 Years
Long-term debt (1)	$ 1,025,000	$ —	$ 275,000	$ —	$ 750,000
Fixed-Rate interest payments (1)	374,531	44,063	88,125	88,125	154,218
Operating leases	129,591	12,698	21,717	20,467	74,709

Drilling commitments (2)	199,472	199,472	—	—	—
Gathering facilities and pipelines (3)	11,058	11,058	—	—	—
Asset retirement obligation (4)	162,666	16,719	— (4)	— (4)	— (4)
Other liabilities (5)	72,098	16,148	35,949	1,877	18,124
Firm transportation	490	374	116	—	—

(1) These amounts do not include interest on the $275 million of bank debt outstanding at March 31, 2014. See Item 3: Quantitative and Qualitative Disclosures About Market Risk for more information regarding fixed and variable rate debt.
(2) Our drilling commitments consist of obligations to finish drilling and completing wells in progress at March 31, 2014.
(3) We have projects in New Mexico and Texas where we are constructing gathering facilities and pipelines. At March 31, 2014, we had commitments of $11.1 million relating to this construction.
(4) We have not included the long-term asset retirement obligations because we are not able to precisely predict the timing of these amounts.
(5) Other liabilities include the estimated value of our commitment associated with our benefit obligations and other miscellaneous commitments.

At March 31, 2014, we had firm sales contracts to deliver approximately 25.8 Bcf of natural gas over the next 12 months. In total, our financial exposure would be approximately $110.2 million should we not deliver this gas. Our exposure will fluctuate with price volatility and actual volumes delivered. However, we believe Cimarex has no financial exposure from these contracts based on our current proved reserves and production levels.

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In the normal course of business we have various delivery commitments which are not material individually or in the aggregate. 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 estimated net cash generated from operations and our other capital resources will be adequate to meet future liquidity needs.

2014 Outlook

Our estimated 2014 E&D capital investment is expected to be approximately $1.9 billion. Following our May 2014 announcement of our intention to acquire certain Mid-Continent properties for approximately $249 million, our total 2014 capital expenditures are now estimated to approximate $2.2 billion.

Our total production volumes for 2014 are now projected to average 822-847 MMcfe per day, a midpoint increase of 20% over 2013. Second-quarter 2014 volumes are expected to average 810-830 MMcfe per day.

Certain expenses for 2014 on a per Mcfe basis are currently estimated as follows:

	2014		
Production expense	$ 1.12	-	$ 1.18
Transportation, processing and other operating	0.65	-	0.70
DD&A and asset retirement obligation	2.70	-	2.80
General and administrative	0.29	-	0.33
Taxes other than income (% of oil and gas revenue)	5.8%	-	6.2%

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies related to oil and gas reserves, full cost accounting, goodwill, 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

No significant accounting standards applicable to Cimarex have been issued during the quarter ended March 31, 2014.

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ITEM 3. QUANTITATIVE AND QUALITATIVE 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 enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production.

The following tables detail the financial derivative contracts we have in place as of March 31, 2014.

Oil Contracts

				Weighted Average Price		Fair Value
Period	Type	Volume/Day	Index (1)	Floor	Ceiling	(in thousands)
Apr 14 – Dec 14	Collars	12,000 Bbls	WTI	$ 85.00	$ 103.47	$ (2,438)

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

Gas Contracts

				Weighted Average Price		Fair Value
Period	Type	Volume/Day	Index (1)	Floor	Ceiling	(in thousands)
Apr 14 – Dec 14	Collars	80,000 MMBtu	PEPL	$ 3.51	$ 4.57	$ (2,101)
Apr 14 – Dec 14	Collars	60,000 MMBtu	Perm EP	$ 3.62	$ 4.50	$ (2,530)

(1) PEPL refers to Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index as quoted in Platt's Inside FERC. Perm EP refers to El Paso Natural Gas Company, Permian Basin Index as quoted in Platt's Inside FERC.

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the 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 2014 of $3.3 million. For the 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 2014 of $3.9 million.

Counterparty credit risk did not have a significant effect on our cash flow calculations and commodity derivative valuations. This is primarily because we have mitigated our exposure to any single counterparty by contracting with numerous counterparties and because 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.

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Interest Rate Risk

At March 31, 2014, our debt was comprised of the following:

(in thousands)	Fixed Rate Debt	Variable Rate Debt
Bank debt	$ —	$ 275,000
5.875% Senior Notes due 2022	750,000	—
Total long-term debt	$ 750,000	$ 275,000

As of March 31, 2014, the amounts outstanding under our five-year senior unsecured revolving credit facility bears interest at either (a) LIBOR plus 1.75-2.5%, based on our leverage ratio, or (b) the higher of (i) a prime rate, (ii) the federal funds effective rate plus 0.50%, or (iii) adjusted one-month LIBOR plus 1.0% plus, in each case, an additional 0.75-1.5%, based on our leverage ratio. In May 2014, our credit facility was amended to extend the term until July 14, 2018 and lower the LIBOR margin from 1.75-2.5% to 1.5-2.25% and lowered the overall margin from 0.75-1.5% to 0.5-1.25%. Our senior unsecured notes bear interest at a fixed rate of 5.875% and will mature on May 1, 2022.

We consider our interest rate exposure to be minimal because approximately 73% of our long-term debt obligations were at fixed rates. An increase of 100 basis points in the interest rate of our variable rate debt would increase our annual interest expense by $2.8 million. This sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 7 to the Consolidated Financial Statements in this report for additional information regarding debt.

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ITEM 4. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Cimarex's management, under the supervision and with the participation of the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of Cimarex's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of March 31, 2014. Based on that evaluation, the CEO and CFO concluded that the disclosure controls and procedures are effective in providing reasonable assurance that 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 designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow such persons to make timely decisions regarding required disclosures.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in our internal control over financial reporting that occurred during the fiscal quarter ended March 31, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II

ITEM 1. LEGAL PROCEEDINGS

In January 2009, the Tulsa County District Court issued a judgment totaling $119.6 million in the H.B. Krug, et al. v. Helmerich & Payne, Inc. (H&P) case. This lawsuit originally was filed in 1998 and addressed H&P's conduct pertaining to a 1989 take-or-pay settlement, along with potential drainage and other related issues. Pursuant to the 2002 spin-off of H&P, Cimarex assumed the assets and liabilities of H&P's exploration and production business, including this lawsuit. In 2008, we recorded a litigation expense of $119.6 million plus additional post-judgment interest and costs after the trial court entered a final judgment for these amounts. On December 10, 2013 the Oklahoma Supreme Court reversed the trial court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. In light of the Oklahoma Supreme Court's ruling, on December 31, 2013, we reduced previously recognized litigation expense and the associated long-term liability by $142.8 million. On March 14, 2014, after denying the Plaintiffs' Petition for Rehearing, the Oklahoma Supreme Court remanded the matter back to the trial court. On March 31, 2014, the trial court entered a final Judgment on Remand for damages of $3.65 million and post-judgment interest and on April 1, 2014, Cimarex wired $15.8 million to Plaintiff's trust account in satisfaction of the judgment plus post-judgment interest and in satisfaction of the payment in lieu of bond. The only issues that now remain are what amounts, if any, Plaintiffs are entitled to receive regarding prejudgment interest, attorney's fees and costs. On April 4, 2014, Cimarex filed a motion asking the trial court to rule that the Plaintiffs are not entitled to any attorney's fees or prejudgment interest. The outcome of these remaining issues cannot be determined at this time. Our current assessments and estimates likely will change in the future as a result of subsequent legal proceedings both in the trial court and on appeal.

Additional information regarding this and other litigation is included in Note 11 to the Consolidated Financial Statements included in Part I, Item 1 of this report.

ITEM 6. EXHIBITS

10.1	First Amendment to Credit Agreement dated as of July 19, 2012 (incorporated by reference from Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 5, 2014)
10.2	Second Amendment to Credit Agreement dated as of May 1, 2014 (incorporated by reference from Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on May 5, 2014)
31.1	Certification of Thomas E. Jorden, 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 Thomas E. Jorden, 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.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

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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.

May 7, 2014

CIMAREX ENERGY CO.

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

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