CIMAREX ENERGY CO
Form 10-Q
May 05, 2016

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, 2016

Commission File No. 001-31446

CIMAREX ENERGY CO.

1700 Lincoln Street, Suite 3700

Denver, Colorado 80203

(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, 2016 was 94,815,010.

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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, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. 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, full cost ceiling impairments to the carrying values of our oil and gas properties, 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, weather 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

(Unaudited)

	March 31, 2016	December 31, 2015
	(in thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 676,639	$ 779,382
Receivables, net	192,160	225,398
Oil and gas well equipment and supplies	44,648	54,579
Derivative instruments	11,868	10,745
Prepaid expenses	5,425	7,036
Other current assets	350	790
Total current assets	931,090	1,077,930
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	15,677,599	15,546,948
Unproved properties and properties under development, not being amortized	466,497	440,166
	16,144,096	15,987,114
Less — accumulated depreciation, depletion, amortization and impairment	(13,057,470)	(12,710,968)
Net oil and gas properties	3,086,626	3,276,146
Fixed assets, net	227,343	230,009
Goodwill	620,232	620,232
Derivative instruments	422	501
Other assets, net	35,548	38,468
	$ 4,901,261	$ 5,243,286
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 39,241	$ 66,815
Accrued liabilities	229,787	247,508
Derivative instruments	3,812	—
Revenue payable	84,252	95,744
Total current liabilities	357,092	410,067
Long-term debt:		
Principal	1,500,000	1,500,000
Less—unamortized debt issuance costs	(13,789)	(14,380)
Long-term debt, net	1,486,211	1,485,620
Deferred income taxes	246,553	352,705
Other liabilities	197,074	197,216

Total liabilities	2,286,930	2,445,608
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, 94,815,010 and 94,820,570 shares issued, respectively	948	948
Paid-in capital	2,773,254	2,762,976
Retained earnings (Accumulated deficit)	(160,397)	33,313
Accumulated other comprehensive income	526	441
	2,614,331	2,797,678
	$ 4,901,261	$ 5,243,286

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Consolidated Statements of Operations and Comprehensive Income (Loss)

(Unaudited)

	For the Three Months Ended March 31,	
	2016	2015
	(in thousands, except per share data)	
Revenues:		
Oil sales	$ 117,573	$ 196,005
Gas sales	82,608	110,962
NGL sales	33,352	45,600
Gas gathering and other	7,241	8,270
Gas marketing, net	(174)	165
	240,600	361,002
Costs and expenses:		
Impairment of oil and gas properties	230,132	603,599
Depreciation, depletion and amortization	128,099	216,778
Asset retirement obligation	2,298	1,736
Production	70,702	82,211
Transportation, processing, and other operating	46,443	39,642
Gas gathering and other	8,080	8,864
Taxes other than income	13,839	21,981
General and administrative	13,897	15,938
Stock compensation	5,528	5,155
(Gain) loss on derivative instruments, net	(428)	—
Other operating, net	90	524
	518,680	996,428
Operating income (loss)	(278,080)	(635,426)
Other (income) and expense:		
Interest expense	20,805	21,256
Capitalized interest	(4,904)	(9,417)
Other, net	(1,650)	(3,585)
Income (loss) before income tax	(292,331)	(643,680)
Income tax expense (benefit)	(106,200)	(228,739)
Net income (loss)	$ (186,131)	$ (414,941)
Earnings (loss) per share to common stockholders:		
Basic	$ (2.00)	$ (4.84)
Diluted	$ (2.00)	$ (4.84)
Dividends per share	$ 0.08	$ 0.16
Comprehensive income (loss):		

Net income (loss)	$ (186,131)	$ (414,941)
Other comprehensive income (loss):		
Change in fair value of investments, net of tax	85	101
Total comprehensive income (loss)	$ (186,046)	$ (414,840)

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Three Months Ended March 31,	
	2016	2015
	(in thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (186,131)	$ (414,941)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Impairment of oil and gas properties	230,132	603,599
Depreciation, depletion and amortization	128,099	216,778
Asset retirement obligation	2,298	1,736
Deferred income taxes	(106,200)	(228,739)
Stock compensation	5,528	5,155
(Gain) loss on derivative instruments	(428)	—
Settlements on derivative instruments	5,068	—
Changes in non-current assets and liabilities	1,863	1,046
Other, net	1,362	2,311
Changes in operating assets and liabilities:		
Receivables, net	33,147	72,397
Other current assets	11,982	9,894
Accounts payable and other current liabilities	(41,660)	(156,063)
Net cash provided by operating activities	85,060	113,173
Cash flows from investing activities:		
Oil and gas expenditures	(176,395)	(371,106)
Sales of oil and gas assets and other assets	13,059	1,180
Other capital expenditures	(9,477)	(18,848)
Net cash used by investing activities	(172,813)	(388,774)
Cash flows from financing activities:		
Dividends paid	(15,104)	(13,947)
Proceeds from exercise of stock options and other	114	4,618
Net cash provided by (used in) financing activities	(14,990)	(9,329)
Net change in cash and cash equivalents	(102,743)	(284,930)
Cash and cash equivalents at beginning of period	779,382	405,862
Cash and cash equivalents at end of period	$ 676,639	$ 120,932

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2016

(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 Annual Report on Form 10-K for the year ended December 31, 2015.

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.

Use of Estimates

Areas of significance requiring the use of management's judgments relate to the estimation of proved oil and gas reserves, the use of proved reserves in calculating depletion, depreciation and amortization (DD&A), 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 also are 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 contingencies.

Oil and Gas Well Equipment and Supplies

Our oil and gas well equipment and supplies are valued at the lower of cost or net realizable value, where net realizable value is a defined estimated selling price. An analysis of our oil and gas well equipment and supplies was performed and no impairment was required. However, the continued industry-wide decline in drilling operations has put downward pressure on the price of oil and gas well equipment and supplies. Further declines in future periods could cause us to recognize impairments on these assets. An impairment would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

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. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess is 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. Estimated future net cash flows are determined by commodity prices and proved reserve quantities.

At March 31, 2016, the carrying value of our oil and gas properties subject to the test exceeded the calculated value of the ceiling limitation, and we recognized an impairment of $230.1 million ($146.2 million, net of tax). This impairment resulted primarily from the continued impact of decreases in the 12-month average trailing prices for oil, natural gas and NGLs utilized in determining the future net cash flows from proved reserves. If pricing conditions stay at current levels or decline further, or if there is a negative impact on one or more of the other components of the calculation, we will incur full cost ceiling impairments in future quarters. The ceiling calculation is not intended to be indicative of the fair market value of our proved reserves or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income (loss) and various components of our balance sheet. Any recorded impairment of oil and gas properties is not reversible at a later date.

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Notes to Consolidated Financial Statements

March 31, 2016

(Unaudited)

Accounts Receivable, Accounts Payable and Accrued Liabilities

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

(in thousands)	March 31, 2016	December 31, 2015
Receivables, net of allowance		
Trade	$ 61,591	$ 81,888
Oil and gas sales	124,189	136,537
Gas gathering, processing, and marketing	6,368	6,935
Other	12	38
Receivables, net	$ 192,160	$ 225,398
Accounts payable		
Trade	$ 25,801	$ 53,384
Gas gathering, processing, and marketing	13,440	13,431
Accounts payable	$ 39,241	$ 66,815
Accrued liabilities		
Exploration and development	$ 44,454	$ 56,721
Taxes other than income	10,731	17,545
Other	174,602	173,242
Accrued liabilities	$ 229,787	$ 247,508

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers (Topic 606). In July 2015, the FASB deferred the effective date by one year to annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. Early adoption is permitted, but not before the original effective date of reporting periods beginning after December 15, 2016. We do not intend to early adopt this standard. At this time we do not expect that the adoption of this standard will have a material effect on our consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, which requires lease assets and lease liabilities for most leases to be recognized on the balance sheet and disclosing key information about leasing arrangements. The standard is effective for reporting periods beginning after December 15, 2018, with early adoption permitted. We are currently evaluating the impact of this new guidance on our consolidated financial statements and related disclosures. We anticipate that we will not early adopt this standard.

In March 2016, the FASB issued ASU 2016-09, which will change how companies account for certain aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. The standard is effective for reporting periods beginning after December 15, 2016. Early adoption is permitted but all of the guidance must be adopted in the same period. We are currently evaluating the impact of this new guidance on our consolidated financial statements and related disclosures. We anticipate that we will not early adopt this standard.

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(Unaudited)

2.Long-Term Debt

Debt at March 31, 2016 and December 31, 2015 consisted of the following:

	March 31, 2016		December 31, 2015	
(in thousands)	Principal	Unamortized Debt Issuance Costs	Principal	Unamortized Debt Issuance Costs
5.875% Senior Notes, due May 1, 2022	$ 750,000	$ 6,649	$ 750,000	$ 6,978
4.375% Senior Notes, due June 1, 2024	750,000	7,140	750,000	7,402
Total long-term debt	$ 1,500,000	$ 13,789	$ 1,500,000	$ 14,380

All of our long-term debt is senior unsecured debt and is, therefore, pari passu with other unsecured debt with respect to the payment of both principal and interest.

Bank Debt

We have a senior unsecured revolving credit facility (Credit Facility) that matures October 16, 2020. The Credit Facility has aggregate commitments of $1.0 billion, with our option to increase aggregate commitments to $1.25 billion at any time. There is no borrowing base subject to the discretion of the lenders based on the value of our proved reserves under the Credit Facility. As of March 31, 2016, there were no borrowings outstanding under the Credit Facility. We had letters of credit outstanding under the Credit Facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

At our option, borrowings under the Credit Facility may bear interest at either (a) LIBOR plus 1.125 – 2.0% based on the credit rating for our senior unsecured long-term debt, or (b) a base rate (as defined in the credit agreement) plus 0.125 – 1.0%, based on the credit rating for our senior unsecured long-term debt. Unused borrowings are subject to a commitment fee of 0.125 – 0.35%, based on the credit rating for our senior unsecured long-term debt.

The Credit Facility contains representations, warranties, covenants and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a total debt-to-capital ratio of no greater than 65%. As of March 31, 2016, we were in compliance with all of the financial and non-financial covenants.

At March 31, 2016 and December 31, 2015, we had $5.4 million and $5.7 million, respectively, of unamortized debt issuance costs associated with our Credit Facility, which were recorded as deferred assets and included in Other assets, net in our balance sheet. These costs are being amortized to interest expense ratably over the life of the Credit Facility.

Senior Notes

Each of our senior notes is governed by an indenture containing certain covenants, events of default and other restrictive provisions with which we were in compliance as of March 31, 2016. Interest on each of the senior notes is payable semi-annually. The effective interest rate on the 4.375% notes and the 5.875% notes, including the debt issuance cost, is 4.50% and 6.04%, respectively.

3.Derivative Instruments/Hedging

We periodically use derivative instruments to mitigate volatility in commodity prices. 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. 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.

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March 31, 2016

(Unaudited)

The following tables summarize our outstanding derivative contracts as of March 31, 2016:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Collars:					
2016:					
Three-Way Collars WTI (1)					
Volume (Bbls)	—	273,000	276,000	276,000	825,000
Wtd Avg Price - Lower Floor	$ —	$ 40.00	$ 40.00	$ 40.00	$ 40.00
Wtd Avg Price - Upper Floor	$ —	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Wtd Avg Price - Ceiling	$ —	$ 60.00	$ 60.00	$ 60.00	$ 60.00
Collars WTI (1)					
Volume (Bbls)	—	364,000	368,000	368,000	1,100,000
Wtd Avg Price - Floor	$ —	$ 35.00	$ 35.00	$ 35.00	$ 35.00
Wtd Avg Price - Ceiling	$ —	$ 42.50	$ 42.50	$ 42.50	$ 42.50
2017:					
Collars WTI (1)					
Volume (Bbls)	360,000	364,000	—	—	724,000
Wtd Avg Price - Floor	$ 35.00	$ 35.00	$ —	$ —	$ 35.00
Wtd Avg Price - Ceiling	$ 42.50	$ 42.50	$ —	$ —	$ 42.50

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Gas Collars:					
2016:					
PEPL (1)					
Volume (MMBtu)	—	2,730,000	2,760,000	2,760,000	8,250,000
Wtd Avg Price - Floor	$ —	$ 2.32	$ 2.32	$ 2.32	$ 2.32
Wtd Avg Price - Ceiling	$ —	$ 2.75	$ 2.75	$ 2.75	$ 2.75
Perm EP (1)					
Volume (MMBtu)	—	3,030,000	2,760,000	2,760,000	8,550,000
Wtd Avg Price - Floor	$ —	$ 2.45	$ 2.42	$ 2.42	$ 2.43

Wtd Avg Price - Ceiling	$ —	$ 2.90	$ 2.87	$ 2.87	$ 2.88
2017:					
PEPL (1)					
Volume (MMBtu)	1,800,000	1,820,000	—	—	3,620,000
Wtd Avg Price - Floor	$ 2.13	$ 2.13	$ —	$ —	$ 2.13
Wtd Avg Price - Ceiling	$ 2.70	$ 2.70	$ —	$ —	$ 2.70
Perm EP (1)					
Volume (MMBtu)	2,700,000	2,730,000	—	—	5,430,000
Wtd Avg Price - Floor	$ 2.42	$ 2.42	$ —	$ —	$ 2.42
Wtd Avg Price - Ceiling	$ 2.97	$ 2.97	$ —	$ —	$ 2.97

(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.

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(Unaudited)

A three-way collar is a combination of three options: lower floor (sold put), upper floor (bought put) and ceiling (sold call). If the published index price is below the lower floor, we receive the difference between the two floors. If the index price is between the two floors, we receive the difference between the upper floor and the index price. If the index price is between the upper floor and the ceiling, we do not receive or pay any amounts. If the index price is above the ceiling, we pay the excess over the ceiling price.

Under a collar agreement, we receive the difference between the published index price and a floor price if the index price is below the floor. We pay the difference between the ceiling price and the index price 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 the ceiling price.

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.

The following table presents the aggregate net (gain) loss from settlements and changes in fair value of our derivative contracts and the (gains) losses only from settlements during the periods shown below.

(in thousands)	Three Months Ended March 31, 2016	2015
(Gain) loss on derivative instruments, net	$ (428)	$ —
Settlement (gains) losses	$ (5,068)	$ —

Our derivative contracts are carried at their fair value on our balance sheet using Level 2 inputs and 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

March 31, 2016

(Unaudited)

The following tables present the amounts and classifications of our derivative assets and liabilities as of March 31, 2016 and December 31, 2015, as well as the potential effect of netting arrangements on contracts with the same counterparty.

March 31, 2016:			
(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$ 5,132	$ —
Natural gas contracts	Current assets — Derivative instruments	6,736	—
Natural gas contracts	Non-current assets — Derivative instruments	422	—
Oil contracts	Current liabilities — Derivative instruments	—	3,812
Oil contracts	Non-current liabilities — Other liabilities	—	1,776
Natural gas contracts	Non-current liabilities — Other liabilities	—	96
Total gross amounts presented in accompanying balance sheet		12,290	5,684
Less: gross amounts not offset in the accompanying balance sheet		(1,802)	(1,802)
Net amount:		$ 10,488	$ 3,882

December 31, 2015:			
(in thousands)	Balance Sheet Location	Asset	Liability
Oil contracts	Current assets — Derivative instruments	$ 6,774	$ —
Natural gas contracts	Current assets — Derivative instruments	3,971	—
Natural gas contracts	Non-current assets — Derivative instruments	501	—
Total gross amounts presented in accompanying balance sheet		11,246	—
Less: gross amounts not offset in the accompanying balance sheet		—	—
Net amount:		$ 11,246	$ —

We are exposed to financial risks associated with our derivative contracts from non-performance by our counterparties. We mitigate our exposure to any single counterparty by contracting with a number of financial institutions, each of which have 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.

4.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 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

March 31, 2016

(Unaudited)

The following table provides fair value measurement information for certain assets and liabilities as of March 31, 2016 and December 31, 2015:

(in thousands)	March 31, 2016 Book Value	March 31, 2016 Fair Value	December 31, 2015 Book Value	December 31, 2015 Fair Value
Financial Assets (Liabilities):				
5.875% Notes due 2022	$ (750,000)	$ (776,250)	$ (750,000)	$ (723,750)
4.375% Notes due 2024	$ (750,000)	$ (739,095)	$ (750,000)	$ (683,318)
Derivative instruments — assets	$ 12,290	$ 12,290	$ 11,246	$ 11,246
Derivative instruments — liabilities	$ (5,684)	$ (5,684)	$ —	$ —

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 fair value (Level 1) of our 4.375% and 5.875% fixed rate notes was based on their last traded value before period end. The fair value of our derivative instruments (Level 2) was estimated using option pricing models. These models use certain variables including forward price and volatility curves and the strike prices for the instruments. The fair value estimates are adjusted relative to non-performance risk as appropriate. See Note 3 for further information on the fair value of our derivative instruments.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, 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.

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, 2016 and December 31, 2015, the allowance for doubtful accounts was $1.6 million and $1.8 million, respectively.

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

March 31, 2016

(Unaudited)

5.Capital Stock

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At March 31, 2016, there were no shares of preferred stock outstanding. A summary of our common stock activity for the three months ended March 31, 2016 follows:

(in thousands)	
Issued and outstanding as of December 31, 2015	94,821
Restricted stock forfeited and retired	(4)
Common stock reacquired and retired	(4)
Option exercises, net of cancellations	2
Issued and outstanding as of March 31, 2016	94,815

Dividends

In February 2016, the Board of Directors declared a cash dividend of $0.08 per share, a decrease from the last dividend declared of $0.16 per share. The dividend is payable on June 1, 2016, to stockholders of record on May 13, 2016. Future dividend payments will depend on our level of earnings, financing requirements, and other factors considered relevant by the Board of Directors.

6.Stock-based Compensation

We have recognized stock-based compensation cost as shown below. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts. During the second quarter of 2016, we accepted volunteers to participate in an early retirement incentive program, which includes accelerated vesting of certain service-based stock awards and stock option awards. At this time, the effect of the accelerated vesting on our total stock compensation cost for the second quarter of 2016 is not determinable.

	Three Months Ended March 31,	
(in thousands)	2016	2015
Restricted stock awards		

Performance stock awards	$ 5,694	$ 4,998
Service-based stock awards	4,165	4,937
	9,859	9,935
Stock option awards	655	639
Total stock compensation cost	10,514	10,574
Less amounts capitalized to oil and gas properties	(4,986)	(5,419)
Compensation expense	$ 5,528	$ 5,155

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7.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, 2016:

(in thousands)		
Asset retirement obligation at January 1, 2016	$	164,105
Liabilities incurred		489
Liability settlements and disposals		(3,739)
Accretion expense		1,894
Revisions of estimated liabilities		350
Asset retirement obligation at March 31, 2016		163,099
Less current obligation		(10,248)
Long-term asset retirement obligation	$	152,851

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8.Earnings (loss) per Share

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

(in thousands, except per share data)	Three Months Ended March 31, 2016	2015
Basic:		
Net income (loss)	$ (186,131)	$ (414,941)
Participating securities’ share in earnings (1)	—	—
Net income (loss) applicable to common stockholders	$ (186,131)	$ (414,941)
Diluted:		
Net income (loss)	$ (186,131)	$ (414,941)
Participating securities’ share in earnings (1)	—	—
Net income (loss) applicable to common stockholders	$ (186,131)	$ (414,941)
Shares:		
Basic shares outstanding	93,000	85,770
Dilutive effect of stock options (2)	—	—
Fully diluted common stock	93,000	85,770
Excluded (2)	2,117	2,216
Earnings (loss) per share to common stockholders:		
Basic	$ (2.00)	$ (4.84)
Diluted	$ (2.00)	$ (4.84)

(1) Participating securities are not included in undistributed earnings when a loss exists.
(2) Inclusion of certain shares would have an anti-dilutive effect.

9.Income Taxes

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

(in thousands)	Three Months Ended March 31, 2016	2015
Current taxes (benefit)	$ —	$ —
Deferred taxes (benefit)	(106,200)	(228,739)
	$ (106,200)	$ (228,739)
Combined Federal and State effective income tax rate	36.3 %	35.5 %

At December 31, 2015, we had a U.S. net tax operating loss carryforward of approximately $907.5 million, which would expire in tax years 2031 through 2035. 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 $77.2 million. We also had an alternative minimum tax credit carryforward of approximately $6.0 million.

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At March 31, 2016, we had no unrecognized tax benefits that would impact our effective tax rate and have made no provisions for interest or penalties related to uncertain tax positions. The tax years 2012 through 2014 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 tax years 2011 through 2014.

Our provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and non-deductible expenses.

10.Commitments and Contingencies

Commitments

We have commitments of $245.4 million to finish drilling and completing wells in progress at March 31, 2016. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $11.4 million.

At March 31, 2016, we had firm sales contracts to deliver approximately 65.1 Bcf of natural gas over the next 31 months. If this gas is not delivered, our financial commitment would be approximately $101.1 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 from which we can fulfill these obligations.

In connection with gas gathering and processing agreements, we have volume commitments over the next ten years. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $196.4 million. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these obligations.

We have minimum volume delivery commitments in connection with agreements to reimburse connection costs to various pipelines. The maximum amount that would be payable if no gas is delivered would be approximately $12.9 million. Of this total, we have accrued a liability of $10.6 million. Due to reduced drilling activity in 2015 and projected for 2016, we may have additional liabilities associated with these delivery commitments in the future.

We have other various transportation, delivery and facilities commitments in the normal course of business, which approximate $39.1 million. We anticipate meeting these obligations.

We have various commitments for office space and equipment under operating lease arrangements totaling $94.3 million.

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

Litigation

We have various litigation matters related to the ordinary course of our business. We assess the probability of estimable amounts related to those 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.

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11.Supplemental Disclosure of Cash Flow Information

	Three Months Ended March 31,	
(in thousands)	2016	2015
Cash paid during the period for:		
Interest expense (including capitalized amounts)	$ 594	$ 935
Interest capitalized	$ 140	$ 414
Income taxes	$ 11	$ 1
Cash received for income taxes	$ 25	$ 300

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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. Currently our operations 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. Our Mid-Continent region consists of Oklahoma and the Texas Panhandle.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our stockholders through a balanced and deep drilling inventory. Our strategy centers on maximizing cash flow from producing properties and profitably reinvesting that cash flow in exploration and development. We consider property acquisitions, dispositions and occasional mergers to enhance our competitive position.

We believe that detailed technical analysis, operational focus and a disciplined capital investment process mitigates risk and positions us to continue to achieve increases in proved reserves and production. Our drilling inventory and limited long-term commitments provide the flexibility to respond quickly to industry volatility.

Our investments are 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 has long been a part of our financial strategy. We believe that maintaining a strong balance sheet mitigates financial risk and enables us to withstand low prices.

Market Conditions

The oil and gas industry is cyclical and commodity prices can be volatile. In the second half of 2014, oil prices began a rapid and significant decline as global supply began to outpace demand. During 2015, global oil supply continued to outpace demand resulting in further deterioration in realized oil prices. Thus far in 2016, oil prices have been erratic and it is likely that they will remain erratic due to the ongoing global supply and demand imbalance, growing inventories and geopolitical factors.

Prices for domestic natural gas and NGLs began to decline during the third quarter of 2014 and continued to be weak in 2015 and thus far in 2016. The declines in these prices are primarily due to an imbalance between supply and demand across North America, which could result in further declines.

Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production. Compared to the first quarter of 2015, our first quarter 2016 realized oil price fell 34% to $28.02/Bbl. Similarly, our realized natural gas price dropped 31% to $1.92/Mcf and our realized price for NGL declined 37% to $9.84/Bbl.

The U.S. oil and gas industry continues to confront weak commodity prices, which has adverse effects on our business and financial position. Our ability to access capital markets may be restricted, which could have an impact on our flexibility to react to changing economic and business conditions. Further, the global oversupply situation could have an adverse impact on our business partners, customers and lenders, potentially causing them to fail to meet their obligations to us.

Based on current economic conditions, our 2016 exploration and development expenditures are projected to range from $650-$700 million. Investments in gathering and processing infrastructure and other fixed assets are expected to approximate an additional $50 million.

See "Risk Factors" in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2015, for a discussion of risk factors that affect our business, financial condition and results of operations. Also see CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS in this report for important information about these types of statements.

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First quarter 2016 summary of operating and financial results compared to the first quarter of 2015:

- Average daily production increased 3% to 973.1 MMcfe per day.
- Oil production declined by 10% to 46,110 barrels per day, gas volumes increased by 6% to 472.9 MMcf per day and NGL volumes rose 16% to 37,263 barrels per day.
- Production revenues declined 34% to $233.5 million.
- Cash on hand at March 31, 2016 was $676.6 million.
- Cash flow provided by operating activities declined 25% to $85.1 million.
- We incurred a net loss of $186.1 million ($2.00 per diluted share) versus a net loss of $414.9 million ($4.84 per diluted share) in 2015.

In response to continued weak commodity prices we significantly reduced our 2016 exploration and development expenditures to $147.0 million compared to $285.5 million in 2015.

Total debt at March 31, 2016 consisted of $1.5 billion of senior notes, with $750 million maturing in 2022 and $750 million maturing in 2024, unchanged from total debt at December 31, 2015.

Revenues

Almost all of our revenues are derived from sales of our oil, natural gas and NGL production. Increases or decreases in our revenue, profitability and future production growth are highly dependent on the commodity prices we receive. Prices are market driven and we expect that future prices will continue to fluctuate due to supply and demand factors, seasonality and geopolitical and economic factors.

Oil sales contributed 51% of our total production revenue for the first quarter of 2016. Gas sales accounted for 35% and NGL sales contributed 14%. A $1.00 per barrel change in our realized oil price would have resulted in a $4.2 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $4.3 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $3.4 million.

The following table presents our average realized commodity prices and certain major U.S. index prices. Our average realized prices do not include settlements of commodity derivative contracts.

	Three Months Ended March 31,	
	2016	2015
Oil Prices:		
Average realized sales price ($/Bbl)	$ 28.02	$ 42.50
Average WTI Midland price ($/Bbl)	$ 34.24	$ 46.65
Average WTI Cushing price ($/Bbl)	$ 33.45	$ 48.63

Gas Prices:		
Average realized sales price ($/Mcf)	$ 1.92	$ 2.77
Average Henry Hub price ($/Mcf)	$ 2.09	$ 2.99
NGL Prices:		
Average realized sales price ($/Bbl)	$ 9.84	$ 15.71

During the first quarter of 2016 and 2015, approximately 79% and 84%, respectively, of our oil production was in the Permian Basin, the sale of which is tied to the WTI Midland benchmark price. The majority of the remaining oil production is from our Mid-Continent region. The impact of changes in realized prices is discussed below under RESULTS OF OPERATIONS.

Operating costs and expenses

Costs associated with producing oil and natural gas are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production and others are a function of the number of wells we own.

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. If the net capitalized cost of our oil and gas properties subject to amortization (the carrying value) exceeds the ceiling limitation, the excess is 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. Estimated future net cash flows are determined by proved reserve quantities and commodity prices net of operating costs and capital expenditures. We recognized ceiling test impairments in each quarter of 2015, totaling $3.7 billion for the year.

At March 31, 2016, the carrying value of our oil and gas properties subject to the ceiling test exceeded the calculated value of the ceiling limitation, resulting in an impairment of $230.1 million ($146.2 million, net of tax). The impairment resulted primarily from the impact of decreases in the 12-month average trailing prices for oil, natural gas and NGLs utilized in determining the estimated future net cash flows from proved reserves. If pricing conditions stay at current levels or decline further, we will incur full cost ceiling impairments in future quarters, the magnitude of which will be affected by one or more of the other components of the ceiling test calculations, until prices stabilize or improve over a twelve-month period.

Commodity prices used in the March 31, 2016 ceiling calculation, based on the required trailing 12-month average prices, were $2.40 per Mcf of gas and $46.26 per barrel of oil. To demonstrate the impact of commodity prices on the ceiling calculation, had average prices of $2.23 per Mcf of gas and $41.34 per barrel of oil been used instead, our pre-tax ceiling test impairment would have been approximately $777.6 million, an increase of $547.5 million for the first quarter of 2016. The lower commodity prices for this assumption were calculated based on a 12-month simple average of the commodity prices on the first day of the month for the 10 months ended April 2016 and the prices for April 2016 were used for the remaining two months in the 12-month average.

The above calculation of the impact of lower commodity prices was prepared based on the assumption that all other inputs and assumptions are held constant with the exception of oil and natural gas prices. Therefore, this calculation strictly isolates the potential impact of commodity prices on our ceiling test limitation. An amount of any future impairment is difficult to reasonably predict and will depend upon not only commodity prices but also other factors that include, but are not limited to, incremental proved reserves that may be added each period, revisions to previous reserve estimates, capital expenditures, operating costs, and all related tax effects. There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in future periods and the estimate described above should not be construed as indicative of our development plans or future results.

The ceiling limitation calculation is not intended to be indicative of the fair market value of our proved reserves or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income (loss) and various components of our balance sheet. Any recorded impairment of oil and gas properties is not reversible at a later date.

Depletion, depreciation 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 realized sales price for future 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 DD&A rate. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, reclassifications of properties from unproved to proved and impairments of oil and gas properties will also impact depletion expense. DD&A is calculated quarterly before the ceiling test impairment calculation. The

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impairments of our oil and gas properties in 2015 resulted in lower DD&A rates in each quarter following the impairment.

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 principally consist of expenditures to prepare and transport production from the wellhead, together with gas processing costs and costs to transport production to a specified sales point. These costs vary by region and will fluctuate with increases or decreases in production volumes, contractual fees and changes in fuel and compression costs.

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.

A discussion of changes in operating costs and expenses is included in RESULTS OF OPERATIONS, below.

RESULTS OF OPERATIONS

Three Months Ended March 31, 2016 vs. March 31, 2015

In the first quarter of 2016, we had a net loss of $186.1 million ($2.00 per diluted share) compared to a net loss of $414.9 million ($4.84 per diluted share) for the same period of 2015. Both 2016 and 2015 periods were adversely affected by low realized commodity prices, which also brought about impairments of our oil and gas properties. Although the first quarter of 2016 had lower production revenue than the same period of 2015, this decrease was more than offset by lower impairment and other operating costs in 2016. Quarter-over-quarter changes are discussed further in the analysis that follows.

Production Revenue			Change Between 2016 / 2015	Price/Volume Change		
(in thousands or as indicated)	2016	2015		Price	Volume	Total
For the Three Months Ended March 31,						
Oil sales	$ 117,573	$ 196,005	(40) %	$ (60,758)	$ (17,674)	$ (78,432)
Gas sales	82,608	110,962	(26) %	(36,579)	8,225	(28,354)
NGL sales	33,352	45,600	(27) %	(19,905)	7,657	(12,248)
	$ 233,533	$ 352,567	(34) %	$ (117,242)	$ (1,792)	$ (119,034)

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	For the Three Months Ended March 31, 2016	For the Three Months Ended March 31, 2015	Change Between 2016 / 2015
Total oil volume — thousand barrels	4,196	4,612	(9) %
Oil volume — barrels per day	46,110	51,241	(10) %
Percent of total equivalent production	28 %	33 %	
Average oil price — per barrel	$ 28.02	$ 42.50	(34) %
Total gas volume — MMcf	43,034	40,125	7 %
Gas volume — MMcf per day	472.9	445.8	6 %
Percent of total equivalent production	49 %	47 %	
Average gas price — per Mcf	$ 1.92	$ 2.77	(31) %
Total NGL volume — thousand barrels	3,391	2,902	17 %
NGL volume — barrels per day	37,263	32,242	16 %
Percent of total equivalent production	23 %	20 %	
Average NGL price — per barrel	$ 9.84	$ 15.71	(37) %
Total equivalent production — MMcfe	88,555	85,206	4 %
Total equivalent production volumes — MMcfe/d	973.1	946.7	3 %

As reflected in the table above, our first quarter 2016 production revenue was 34% lower than that of 2015. Increased revenue from higher natural gas and NGL production volumes were more than offset by decreased revenues from lower realized commodity prices and lower oil production. See Revenues above for a discussion regarding realized prices. The decrease in oil production resulted primarily from capacity curtailments in the Permian Basin region due to force majeure and other events beyond our control.

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The table below reflects our regional production volumes.

	For the Three Months Ended March 31,	
	2016	2015
Oil (Bbls per day)		
Permian Basin	36,549	43,089
Mid-Continent	9,253	7,436
Other	308	716
	46,110	51,241
Gas (MMcf per day)		
Permian Basin	173.6	150.4
Mid-Continent	298.4	287.0
Other	0.9	8.4
	472.9	445.8
NGL (Bbls per day)		
Permian Basin	14,059	13,156
Mid-Continent	23,148	18,762
Other	56	324
	37,263	32,242
Total Equivalent (MMcfe per day)		
Permian Basin	477.3	487.8
Mid-Continent	492.8	444.1
Other	3.0	14.8
	973.1	946.7

Other revenues

We sometimes transport, process and market third-party gas that is associated with our equity gas. The table below reflects income from third-party gas gathering and processing and our net marketing margin (revenues less purchases) for marketing third-party gas. We market and sell natural gas for working interest owners under short-term sales and supply agreements and may earn a fee for such services.

	For the Three Months Ended March 31,	
	2016	2015
Gas Gathering and Marketing (in thousands):		
Gas gathering and other revenues	$ 7,241	$ 8,270
Gas marketing revenues, net of related costs	$ (174)	$ 165

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

Analysis of Operating Costs and Expenses

As reflected in the table below, total operating costs and expenses in the first quarter of 2016 were $477.7 million (48%) lower than those for the same period of 2015. Most of the 2016 decrease was due to a smaller ceiling test impairment of our oil and gas properties and lower DD&A expense. See Operating costs and expenses above for a discussion of the ceiling limitation and DD&A calculations. Period-over-period differences are discussed below.

	For the Three Months Ended March 31, 2016	2015	Variance Between 2016 / 2015	Per Mcfe 2016	2015
Operating costs and expenses (in thousands, except per Mcfe):					
Impairment of oil and gas properties	$ 230,132	$ 603,599	$ (373,467)	N/A	N/A
DD&A	128,099	216,778	(88,679)	$ 1.45	$ 2.54
Asset retirement obligation	2,298	1,736	562	$ 0.03	$ 0.02
Production	70,702	82,211	(11,509)	$ 0.80	$ 0.97
Transportation, processing and other operating	46,443	39,642	6,801	$ 0.52	$ 0.47
Gas gathering and other	8,080	8,864	(784)	$ 0.09	$ 0.10
Taxes other than income	13,839	21,981	(8,142)	$ 0.16	$ 0.26
General and administrative	13,897	15,938	(2,041)	$ 0.16	$ 0.19
Stock compensation	5,528	5,155	373	$ 0.06	$ 0.06
(Gain) loss on derivative instruments, net	(428)	—	(428)	N/A	N/A
Other operating, net	90	524	(434)	N/A	N/A
	$ 518,680	$ 996,428	$ (477,748)		

First quarter 2016 DD&A expense was 41% lower than the same period of 2015. Most of the decrease was due to a lower DD&A rate in 2016. Impairments of our oil and gas properties during each quarter of 2015 resulted in lower DD&A rates in each quarter following the impairment. DD&A is calculated quarterly before the ceiling test impairment calculation. We expect our DD&A rate during 2016 to fluctuate depending on average realized prices. Continued lower realized prices will result in further impairments of our oil and gas properties which would likely result in a lower DD&A rate in the quarter following an impairment.

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

(in thousands, except per Mcfe)	For the Three Months Ended March 31, 2016	2015	Variance Between 2016 / 2015	Per Mcfe 2016	2015
Lease operating expense	$ 55,694	$ 68,505	$ (12,811)	$ 0.63	$ 0.80
Workover expense	15,008	13,706	1,302	$ 0.17	$ 0.17
	$ 70,702	$ 82,211	$ (11,509)	$ 0.80	$ 0.97

Lease operating expense in the first quarter of 2016 declined 19% compared to the same quarter of 2015. The decline was primarily a result of lower salt water disposal costs, reduced costs due to property divestitures and various other decreases in costs due to concerted efforts to implement operational efficiencies.

For the three months ended March 31, 2016, workover expense was 9% higher than the same period of 2015. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Transportation, processing and other operating costs in the first quarter of 2016 were 17% greater than the first quarter of 2015. These costs will vary by product type and region. The 2016 increase is primarily due to higher processing volumes and fees in our Mid-Continent region. In addition, approximately 14% of the 2016 increase relates to accruals for expected minimum volume agreement shortfalls. See Contractual Obligations and Material Commitments below for further information.

Gas gathering and other includes costs associated with operating our gas gathering and processing infrastructure, including product costs, operating and maintenance expenses.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based production and severance taxes are our largest component of these taxes. The

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37% decrease in these taxes for the first quarter of 2016 compared to 2015 was primarily a result of the quarter-over-quarter decline in production revenue due to lower realized commodity prices.

G&A costs were as follows:

	For the Three Months Ended March 31,		Variance Between 2016 /
(in thousands)	2016	2015	2015
G&A capitalized to oil & gas properties	$ 16,162	$ 16,231	$ (69)
G&A expense	13,897	15,938	(2,041)
Total G&A cost	$ 30,059	$ 32,169	$ (2,110)
G&A expense per Mcfe	$ 0.16	$ 0.19	$ (0.03)

During the first quarter of 2016, total G&A cost declined 7% compared to the first quarter of 2015. The decrease resulted from a concerted effort to reduce our overall G&A expenditures. During the second quarter of 2016, we accepted volunteers to participate in an early retirement incentive program. As a result of this program, we expect our second quarter 2016 total G&A cost to be approximately 20% higher than that of the first quarter of 2016. Going forward these departures are expected to result in lower G&A.

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

	For the Three Months Ended March 31,		Variance Between 2016 /
(in thousands)	2016	2015	2015
Restricted stock awards			
Performance stock awards	$ 5,694	$ 4,998	$ 696
Service-based stock awards	4,165	4,937	(772)
	9,859	9,935	(76)
Stock option awards	655	639	16
Total stock compensation cost	10,514	10,574	(60)

Less amounts capitalized	(4,986)	(5,419)	433
Stock compensation	$ 5,528	$ 5,155	$ 373

Expense associated with stock compensation will fluctuate based on the grant-date fair value of awards, the number of awards and the timing of the awards. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts. During the second quarter of 2016, we accepted volunteers to participate in an early retirement incentive program, which includes accelerated vesting of certain service-based stock awards and stock option awards. At this time, the effect of the accelerated vesting on our total stock compensation cost for the second quarter of 2016 is not determinable.

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity prices and the monthly settlement (if any) of the instruments. We have chosen not to apply hedge accounting treatment to our derivative instruments. Therefore, settlements on the contracts are included as a component of operating costs and expenses as either a net gain or loss on derivative instruments.

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The following table presents the aggregate net (gain) loss from settlements and change in the fair value of our derivative contracts and the (gains) losses only from settlements during 2016 and 2015. See Note 3 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

	Three Months Ended March 31,	
(in thousands)	2016	2015
(Gain) loss on derivative instruments, net	$ (428)	$ —
Settlement (gains) losses	$ (5,068)	$ —

Other (income) and expense

	For the Three Months Ended March 31,		Variance Between 2016 /
(in thousands)	2016	2015	2015
Interest expense	$ 20,805	$ 21,256	$ (451)
Capitalized interest	(4,904)	(9,417)	4,513
Other, net	(1,650)	(3,585)	1,935
	$ 14,251	$ 8,254	$ 5,997

The majority of our interest expense relates to interest on debt and amortization of financing costs. See Long-term Debt below for further information regarding our debt.

We capitalize interest on non-producing leasehold (NPL) costs, the in-progress costs of drilling and completing wells and constructing qualified assets. Capitalized interest will fluctuate based on the current rate of interest and the amount of costs on which interest is calculated. During the first quarter of 2016, the average balance of NPL was approximately 46% lower than the cost in the first quarter of 2015 resulting in a 48% decrease in capitalized interest.

Components of “Other, net” consist of miscellaneous income and expense items that will vary from period to period, including gain or loss related to the sale or value of oil and gas well equipment and supplies, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. The 54% quarter-over-quarter decrease was primarily due to lower gains from sales of oil and gas well equipment and supplies in 2016.

An analysis of our oil and gas well equipment and supplies was performed and no impairment was required. However, the industry-wide decline in drilling operations has put downward pressure on the price of oil and gas well equipment and supplies. Further declines in future periods could cause us to recognize impairments on these assets. An impairment would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

Income Tax Expense

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

	Three Months Ended March 31,	
(in thousands)	2016	2015
Current benefit	$ —	$ —
Deferred tax expense (benefit)	$ (106,200)	$ (228,739)
	$ (106,200)	$ (228,739)
Combined Federal and State effective income tax rate	36.3 %	35.5 %

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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 9 to the Consolidated Financial Statements of this report for additional information regarding our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We strive to maintain an adequate liquidity level to address volatility and risk. Sources of liquidity include our cash flow from operations, cash on hand, available borrowing capacity under our revolving credit facility proceeds from sales of non-core assets and occasional public financings.

Our liquidity is highly dependent on prices we receive for the oil, natural gas and NGLs we produce. Prices we receive are determined by prevailing market conditions and greatly influence our revenue, cash flow, profitability, access to capital and future rate of growth. See Market Conditions, Revenues and RESULTS OF OPERATIONS above for further information and analysis of the impact realized prices have had on our 2016 earnings.

We deal with volatility in commodity prices primarily by maintaining flexibility in our capital investment program. We have a balanced and deep drilling inventory and limited long-term commitments, which enables us to respond quickly to industry volatility. See Capital Expenditures below for information regarding our 2016 exploration and development investment program.

From time to time we enter into hedging agreements. We currently have derivative contracts covering a portion of our 2016 and 2017 production. See Note 3 to the Consolidated Financial Statements of this report for information regarding our derivative instruments. Management will decide whether to enter into derivative contracts depending on their view of underlying supply and demand trends, changes in the oil and gas futures markets and other considerations.

We believe our conservative use of leverage and strong balance sheet will mitigate our exposure to lower prices. Cash and cash equivalents at March 31, 2016 totaled $676.6 million. Our long-term debt consisted of $1.5 billion of senior notes, with $750 million due in 2022 and $750 million due in 2024. We had letters of credit outstanding under our credit facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

Our debt to total capitalization at March 31, 2016 was 36%, compared to 35% at December 31, 2015. The reconciliation of debt to total capitalization, which is a non-GAAP measure, is: long-term debt of $1.50 billion divided by the sum of long-term debt of $1.50 billion plus stockholders' equity of $2.61 billion. Management believes this non-GAAP measure is useful information as it is a common statistic used in the investment community to assist with analysis of the financial condition of an entity.

We expect our operating cash flow and other capital resources to be adequate to meet our needs for planned capital expenditures, working capital, debt service and dividend payments for the remainder of 2016 and beyond.

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

Net cash flow provided by operating activities (operating cash flow) for the first quarter of 2016 was $85.1 million, down 25% from $113.2 million in the same period of 2015. The $28.1 million decrease resulted primarily from a quarter-over-quarter decrease in production revenue, which was partially offset by net decreases in operating expenses. See RESULTS OF OPERATIONS above for information regarding the 2016 decreases in production revenue and certain operating expenses.

For the first three months of 2016, net cash flow used for investing activities was $172.8 million, a decrease of $216.0 million (56%) from $388.8 million in the first three months of 2015. In 2016, oil and gas and other capital expenditures of $185.9 million were partially offset by proceeds from asset sales of $13.1 million. In 2015, oil and gas and other capital expenditures of $390.0 million were partially offset by proceeds from asset sales of $1.2 million.

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During the first quarter of 2016, net cash used in financing activities was $15.0 million, compared to $9.3 million for the same period of 2015. In 2016, dividend payments of $15.1 million were only offset by $0.1 million of proceeds from issuance of common stock from employee option exercises and other. In 2015, dividend payments of $13.9 million were partially offset by $4.6 million of proceeds from issuance of common stock from employee option exercises and other.

Reconciliation of Adjusted Cash Flow from Operations

	Three Months Ended March 31,	
(in thousands)	2016	2015
Net cash provided by operating activities	$ 85,060	$ 113,173
Change in operating assets and liabilities	(3,469)	73,772
Adjusted cash flow from operations	$ 81,591	$ 186,945

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 and dividends 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.

Capital Expenditures

The following table reflects capitalized expenditures for oil and gas acquisitions, exploration and development (E&D) activities and property sales.

	Three Months Ended March 31,	
(in thousands)	2016	2015
Acquisitions:		
Proved	$ 2,584	$ 30
Unproved	8,346	1,869
	10,930	1,899
Exploration and development:		
Land and seismic	11,162	22,690
Exploration and development	147,022	285,527
	158,184	308,217

Sales proceeds:		
Proved	(12,587)	(1,145)
Unproved	(384)	—
	(12,971)	(1,145)
	$ 156,143	$ 308,971

Amounts in the table above are presented on an accrual basis. The Condensed Consolidated Statements of Cash Flows in this report reflect activities on a cash basis, when payments are made or received.

Our 2016 E&D capital investment is presently expected to range from $650-$700 million. Our expectation is that 55% of our 2016 capital investment will be in the Permian Basin with the remaining 45% in the Mid-Continent region. Based on our current development plans, our estimates of proved reserves have yet to be materially impacted by our response to lower prices.

As has been our historical practice, we regularly review our capital expenditures throughout the year and will adjust our investments based on increases or decreases in commodity prices, service costs and drilling success.

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We have the flexibility to adjust our capital expenditures based upon market conditions. Due to the uncertainty of the duration of a low commodity price environment, with the possibility of further declines in prices, our current plan for the pace of development of our proved undeveloped reserves could change in the future.

We intend to continue to fund our capital investment program with cash on hand and cash flow from our operating activities. Sales of non-core assets and borrowings under our credit facility may also be used to supplement funding of capital expenditures. The timing of capital expenditures and the receipt of cash flows do not necessarily match, which may cause us to borrow and repay funds under our Credit Facility from time-to-time. See Bank Debt below for further information regarding our credit facility.

The following table reflects wells brought on production by region.

	Three Months Ended March 31,	
	2016	2015
Gross wells		
Permian Basin	7	42
Mid-Continent	15	11
Other	—	—
	22	53
Net wells		
Permian Basin	3	30
Mid-Continent	2	3
Other	—	—
	5	33

As of March 31, 2016, we had 93 gross wells awaiting completion: 25 Permian Basin and 68 Mid-Continent. We also had ten operated rigs running: six in the Permian Basin and four in the Mid-Continent region.

We have made, and will continue to make, expenditures to comply with environmental and safety regulations and requirements. These costs are considered a normal recurring cost of our ongoing operations. 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, based on current laws and regulations. While we expect pending or new legislation or regulations to increase the cost of business, at this time it is not possible to quantify the impact on our business. Compliance with pending or new legislation or regulations could increase our costs or adversely affect demand for oil or gas and result in a material adverse effect on our financial position or operations.

Financial Condition

During the first three months of 2016, our total assets decreased $342.0 million (7%) to $4.9 billion, compared to $5.2 billion at December 31, 2015. The decrease was mainly attributable to the $230.1 million impairment of our oil and gas properties and a $102.7 million decrease in cash and cash equivalents.

Total liabilities declined by $158.7 million (6%) to $2.3 billion at March 31, 2016, compared to $2.4 billion at December 31, 2015. Approximately $53.0 million of the decrease relates to a decrease in total current liabilities, which was primarily related to our oil and gas operations and drilling activity. The remaining decrease is mainly due to a $106.2 million decrease in deferred income taxes stemming from our net loss for the first quarter of 2016.

Stockholders' equity totaled $2.6 billion at March 31, 2016, down 7% from $2.8 billion at December 31, 2015. Decreases resulted mainly from a net loss of $186.1 million for the first three months of 2016 and accrued dividends of $7.6 million.

The decreases in our total assets, liabilities and stockholders' equity and our net loss during the first quarter of 2016 resulted primarily from the continued impact of lower realized commodity prices which resulted in lower

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production revenues and an impairment of our oil and gas properties. See RESULTS OF OPERATIONS above for further information.

Long-term Debt

Long-term debt at March 31, 2016 and December 31, 2015, consisted of the following:

	March 31, 2016		December 31, 2015	
(in thousands)	Principal	Unamortized Debt Issuance Costs	Principal	Unamortized Debt Issuance Costs
5.875% Senior Notes, due May 1, 2022	$ 750,000	$ 6,649	$ 750,000	$ 6,978
4.375% Senior Notes, due June 1, 2024	750,000	7,140	750,000	7,402
Total long-term debt	$ 1,500,000	$ 13,789	$ 1,500,000	$ 14,380

At March 31, 2016 and December 31, 2015, we had no bank debt outstanding. All of our long-term debt is senior unsecured debt and is, therefore, pari passu with other unsecured debt with respect to the payment of both principal and interest.

Bank Debt

Our senior unsecured revolving credit facility (Credit Facility) has an aggregate commitment from the lenders of $1.0 billion and matures on October 16, 2020. We have the option to increase the commitment to $1.25 billion at any time. The Credit Facility is not a borrowing base facility subject to the discretion of the lenders and is not based on the value of our proved reserves.

At March 31, 2016, we had letters of credit outstanding of $2.5 million under the Credit Facility, leaving an unused borrowing availability of $997.5 million. We did not have any bank debt outstanding during the first quarter of 2016 or 2015.

The Credit Facility contains representations, warranties, covenants and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a defined total debt-to-capital ratio of no greater than 65%. As of March 31, 2016, we were in compliance with all of the financial and non-financial covenants. For further information regarding the terms of the Credit Facility see Note 2 to the Consolidated Financial Statements of this report.

Senior Notes

Interest on our senior notes is payable semi-annually. Each of the senior notes is governed by an indenture containing customary covenants, events of default and other restrictive provisions with which we were in compliance at March 31, 2016.

Working Capital Analysis

Our working capital fluctuates primarily as a result of our realized commodity prices, increases or decreases in our production volumes, changes in receivables and payables related to our operating and E&D activities, changes in our oil and gas well equipment and supplies and changes in our cash and cash equivalents.

At March 31, 2016, we had working capital of $574.0 million, a decrease of $93.9 million compared to working capital of $667.9 million at December 31, 2015.

Working capital decreases consisted of the following:

- Cash and cash equivalents decreased by $102.7 million.
- Operations-related accounts receivable decreased by $33.2 million.
- Oil and gas well equipment and supplies decreased by $9.9 million.

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· Net derivative instruments and prepaid expenses decreased by $2.7 million and $1.6 million, respectively.

Decreases in working capital were partially offset by the following increases:

· Operations-related accounts payable and accrued liabilities decreased by $44.5 million.
  · Accrued liabilities related to our E&D expenditures decreased by $12.3 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.

Dividends

A quarterly cash dividend has been paid to stockholders every quarter since the first quarter of 2006. In February 2016, the quarterly dividend was decreased to $0.08 per share from $0.16 per share. Future dividend payments will depend on our level of earnings, financing requirements, and other factors considered relevant by our Board of Directors.

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, 2016, 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, 2016, 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)	$ 1,500,000	$ —	$ —	$ —	$ 1,500,000
Fixed-Rate interest payments (1)	565,312	76,876	153,750	153,750	180,936
Operating leases	94,259	9,371	18,473	18,605	47,810
Drilling commitments (2)	256,832	246,252	10,580	—	—
Asset retirement obligation (3)	163,099	10,248	— (3)	— (3)	— (3)
Other liabilities (4)	140,003	45,579	64,095	1,993	28,336
Firm transportation	30,902	7,155	9,903	4,427	9,417

(1)

See Item 3: Quantitative and Qualitative Disclosures About Market Risk for more information regarding fixed and variable rate debt.

(2) We have drilling commitments of approximately $245.4 million consisting of obligations to finish drilling and completing wells in progress at March 31, 2016. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $11.4 million.

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

(4) Other liabilities include the estimated value of our commitment associated with our benefit obligations and other miscellaneous commitments.

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At March 31, 2016, we had firm sales contracts to deliver approximately 65.1 Bcf of natural gas over the next 31 months. If this gas is not delivered, our financial commitment would be approximately $101.1 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 from which we can fulfill these obligations.

In connection with gas gathering and processing agreements, we have volume commitments over the next ten years. If no gas is delivered, the maximum amount that would be payable under these commitments would be approximately $196.4 million. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these obligations.

We have minimum volume delivery commitments in connection with agreements to reimburse connection costs to various pipelines. The maximum amount that would be payable if no gas is delivered would be approximately $12.9 million. Of this total, we accrued a liability of $10.6 million. Due to reduced drilling activity in 2015 and projected for 2016, we may have additional liabilities associated with these delivery commitments in the future.

We have other various transportation, delivery and facilities commitments in the normal course of business, which approximate $39.1 million. We anticipate meeting these obligations.

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

Taking into account current commodity prices and anticipated levels of production, we believe that our net cash flow generated from operations and our other capital resources will be adequate to meet future obligations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We consider accounting policies related to oil and gas reserves, full cost accounting, goodwill, contingencies, asset retirement obligations and income taxes to be critical policies and estimates. These are summarized in Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2015.

Recent Accounting Developments

Please refer to Note 1, Basis of Presentation – Recently Issued Accounting Standards, to the Consolidated Financial Statements in this report for a discussion of recent accounting pronouncements and their anticipated effect on our business.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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, gas and NGL 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, gas and NGL production has been volatile and unpredictable. Oil sales contributed 51% of our total production revenue for the first three months of 2016. Gas sales accounted for 35% and NGL sales contributed 14%. A $1.00 per barrel change in our realized oil price would have resulted in a $4.2 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $4.3 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $3.4 million.

We periodically enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production. At March 31, 2016, we have gas collars in place for the years 2016 and 2017 with a net total fair value asset of $7.1 million. We have oil collars in place for the years 2016 and 2017 with a net total fair value liability of $456 thousand. See Note 3 to the Consolidated Financial Statements in this report for additional information regarding derivative instruments.

While these contracts limit the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. For the gas contracts described above, a hypothetical $0.10 change in the price below or above the contracted price applied to the notional amounts would cause a change of $2.6 million in our gain (loss) on mark-to-market derivatives in 2016. For the oil contracts described above, a hypothetical $1.00 change in the price below or above the contracted price applied to the notional amounts would cause a change of $2.6 million in our gain (loss) on mark-to-market derivatives in 2016.

Interest Rate Risk

At March 31, 2016, our long-term debt consisted of $750 million in 5.875% senior notes that will mature on May 1, 2022 and $750 million in 4.375% senior notes that will mature on June 1, 2024. Because all of our long-term debt is at a fixed rate, we consider our interest rate exposure to be minimal. 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 2 and Note 4 to the Consolidated Financial Statements in this report for additional information regarding debt.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Cimarex management, under the supervision and with the participation of the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of 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, 2016. 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, 2016 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

The information set forth under the heading “Litigation” in Note 10 to the Consolidated Financial Statements included in Part I, Item 1 of this report is incorporated by reference in response to this item.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2015. There have been no material changes in our risk factors from those described in the Annual Report on Form 10-K for the year ended December 31, 2015. The risks described in the Annual Report on Form 10-K for the year ended December 31, 2015 are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

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ITEM 6. EXHIBITS

3.1	Corrected Amended and Restated By-laws of Cimarex Energy Co. dated November 11, 2015 (filed as Exhibits 3.1 and 3.2 to the Current Report on Form 8-K/A filed on April 21, 2016 (Commission File No. 001-31446) and incorporated herein by reference).
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 G. Mark Burford, 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 G. Mark Burford, 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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SIGNATURES

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 5, 2016

CIMAREX ENERGY CO.

/s/ G. Mark Burford
G. Mark Burford
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)