CIMAREX ENERGY CO
Form 10-Q
August 04, 2016
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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 June 30, 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 June 30, 2016 was 94,986,852.

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CIMAREX ENERGY CO.

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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)

| | June 30, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands, except share data) | |
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $ 641,739 | $ 779,382 |
| Receivables, net | 229,634 | 225,398 |
| Oil and gas well equipment and supplies | 37,852 | 54,579 |
| Derivative instruments | 1,119 | 10,745 |
| Prepaid expenses | 5,090 | 7,036 |
| Other current assets | 2,173 | 790 |
| Total current assets | 917,607 | 1,077,930 |
| Oil and gas properties at cost, using the full cost method of accounting: | | |
| Proved properties | 15,845,260 | 15,546,948 |
| Unproved properties and properties under development, not being amortized | 458,530 | 440,166 |
| | 16,303,790 | 15,987,114 |
| Less — accumulated depreciation, depletion, amortization and impairment | (13,569,032) | (12,710,968) |
| Net oil and gas properties | 2,734,758 | 3,276,146 |
| Fixed assets, net | 224,056 | 230,009 |
| Goodwill | 620,232 | 620,232 |
| Derivative instruments | — | 501 |
| Other assets, net | 35,170 | 38,468 |
| | $ 4,531,823 | $ 5,243,286 |
| Liabilities and Stockholders' Equity | | |
| Current liabilities: | | |
| Accounts payable | $ 55,564 | $ 66,815 |
| Accrued liabilities | 220,154 | 247,508 |
| Derivative instruments | 28,399 | — |
| Revenue payable | 99,209 | 95,744 |
| Total current liabilities | 403,326 | 410,067 |
| Long-term debt: | | |
| Principal | 1,500,000 | 1,500,000 |
| Less—unamortized debt issuance costs | (13,205) | (14,380) |
| Long-term debt, net | 1,486,795 | 1,485,620 |
| Deferred income taxes | 92,446 | 352,705 |
| Other liabilities | 202,454 | 197,216 |

| | | |
|---|---|---|
| Total liabilities | 2,185,021 | 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, 94,986,852 and 94,820,570 shares issued, respectively | 950 | 948 |
| Paid-in capital | 2,775,805 | 2,762,976 |
| Retained earnings (Accumulated deficit) | (430,674) | 33,313 |
| Accumulated other comprehensive income | 721 | 441 |
| Total stockholders' equity | 2,346,802 | 2,797,678 |
| | $ 4,531,823 | $ 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 June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (in thousands, except per share data) | | | |
| Revenues: | | | | |
| Oil sales | $ 162,005 | $ 259,344 | $ 279,578 | $ 455,349 |
| Gas sales | 76,615 | 106,374 | 159,223 | 217,336 |
| NGL sales | 51,939 | 49,477 | 85,291 | 95,077 |
| Gas gathering and other | 8,211 | 9,141 | 15,452 | 17,411 |
| Gas marketing, net | 103 | (53) | (71) | 112 |
| | 298,873 | 424,283 | 539,473 | 785,285 |
| Costs and expenses: | | | | |
| Impairment of oil and gas properties | 399,194 | 967,287 | 629,326 | 1,570,886 |
| Depreciation, depletion and amortization | 123,877 | 217,451 | 251,976 | 434,229 |
| Asset retirement obligation | 1,750 | 2,042 | 4,048 | 3,778 |
| Production | 57,213 | 70,600 | 127,915 | 152,811 |
| Transportation, processing, and other operating | 44,436 | 43,713 | 90,879 | 83,355 |
| Gas gathering and other | 7,492 | 11,306 | 15,572 | 20,170 |
| Taxes other than income | 14,066 | 25,980 | 27,905 | 47,961 |
| General and administrative | 21,424 | 14,054 | 35,321 | 29,992 |
| Stock compensation | 7,490 | 4,988 | 13,018 | 10,143 |
| (Gain) loss on derivative instruments, net | 33,236 | — | 32,808 | — |
| Other operating, net | 24 | 260 | 114 | 784 |
| | 710,202 | 1,357,681 | 1,228,882 | 2,354,109 |
| Operating income (loss) | (411,329) | (933,398) | (689,409) | (1,568,824) |
| Other (income) and expense: | | | | |
| Interest expense | 20,824 | 21,297 | 41,629 | 42,553 |
| Capitalized interest | (5,633) | (8,570) | (10,537) | (17,987) |
| Other, net | (2,011) | (3,854) | (3,661) | (7,439) |
| Income (loss) before income tax | (424,509) | (942,271) | (716,840) | (1,585,951) |
| Income tax expense (benefit) | (154,219) | (342,056) | (260,419) | (570,795) |
| Net income (loss) | $ (270,290) | $ (600,215) | $ (456,421) | $ (1,015,156) |
| | | | | |
| Earnings (loss) per share to common stockholders: | | | | |
| Basic | $ (2.91) | $ (6.47) | $ (4.91) | $ (10.94) |
| Diluted | $ (2.91) | $ (6.47) | $ (4.91) | $ (10.94) |
| | | | | |
| Dividends per share | $ 0.08 | $ 0.16 | $ 0.16 | $ 0.32 |
| | | | | |
| Comprehensive income (loss): | | | | |

| | | | | |
|---|---|---|---|---|
| Net income (loss) | $ (270,290) | $ (600,215) | $ (456,421) | $ (1,015,156) |
| Other comprehensive income (loss): | | | | |
| Change in fair value of investments, net of tax | 195 | (292) | 280 | (190) |
| Total comprehensive income (loss) | $ (270,095) | $ (600,507) | $ (456,141) | $ (1,015,346) |

See accompanying notes to consolidated financial statements.

CIMAREX ENERGY CO.

Condensed Consolidated Statements of Cash Flows

(Unaudited)

| | For the Six Months Ended June 30, | |
|---|---|---|
| | 2016 | 2015 |
| | (in thousands) | |
| Cash flows from operating activities: | | |
| Net income (loss) | $ (456,421) | $ (1,015,156) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Impairment of oil and gas properties | 629,326 | 1,570,886 |
| Depreciation, depletion and amortization | 251,976 | 434,229 |
| Asset retirement obligation | 4,048 | 3,778 |
| Deferred income taxes | (260,419) | (570,795) |
| Stock compensation | 13,018 | 10,143 |
| (Gain) loss on derivative instruments | 32,808 | — |
| Settlements on derivative instruments | 8,927 | — |
| Changes in non-current assets and liabilities | 2,548 | 2,942 |
| Other, net | 2,644 | 3,276 |
| Changes in operating assets and liabilities: | | |
| Receivables, net | (4,327) | 92,473 |
| Other current assets | 17,328 | 16,121 |
| Accounts payable and other current liabilities | (27,752) | (177,352) |
| Net cash provided by operating activities | 213,704 | 370,545 |
| Cash flows from investing activities: | | |
| Oil and gas expenditures | (325,058) | (599,222) |
| Sales of oil and gas assets and other assets | 12,854 | 9,233 |
| Other capital expenditures | (17,774) | (35,882) |
| Net cash used by investing activities | (329,978) | (625,871) |
| Cash flows from financing activities: | | |
| Proceeds from sale of common stock | — | 752,100 |
| Financing and underwriting fees | (1) | (22,563) |
| Dividends paid | (22,655) | (28,129) |
| Proceeds from exercise of stock options and other | 1,287 | 4,936 |
| Net cash provided by (used in) financing activities | (21,369) | 706,344 |
| Net change in cash and cash equivalents | (137,643) | 451,018 |
| Cash and cash equivalents at beginning of period | 779,382 | 405,862 |
| Cash and cash equivalents at end of period | $ 641,739 | $ 856,880 |

See accompanying notes to consolidated financial statements.

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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 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 include 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 June 30, 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 $399.2 million ($253.6 million, net of tax). Year-to-date 2016 impairments totaled $629.3 million ($400.0 million, net of tax). These impairments 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

June 30, 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) | June 30, 2016 | December 31, 2015 |
|---|---|---|
| Receivables, net of allowance | | |
| Trade | $ 54,188 | $ 81,888 |
| Oil and gas sales | 166,866 | 136,537 |
| Gas gathering, processing, and marketing | 8,568 | 6,935 |
| Other | 12 | 38 |
| Receivables, net | $ 229,634 | $ 225,398 |
| | | |
| Accounts payable | | |
| Trade | $ 39,224 | $ 53,384 |
| Gas gathering, processing, and marketing | 16,340 | 13,431 |
| Accounts payable | $ 55,564 | $ 66,815 |
| | | |
| Accrued liabilities | | |
| Exploration and development | $ 46,761 | $ 56,721 |
| Taxes other than income | 15,947 | 17,545 |
| Other | 157,446 | 173,242 |
| Accrued liabilities | $ 220,154 | $ 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 do not intend to early adopt this standard.

CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2016

(Unaudited)

## 2.Long-Term Debt

Debt at June 30, 2016 and December 31, 2015 consisted of the following:

| | June 30, 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 | $ 6,324 | $ 750,000 | $ 6,978 |
| 4.375% Senior Notes, due June 1, 2024 | 750,000 | 6,881 | 750,000 | 7,402 |
| Total long-term debt | $ 1,500,000 | $ 13,205 | $ 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 June 30, 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 defined total debt-to-capital ratio of no greater than 65%. As of June 30, 2016, we were in compliance with all of the financial and non-financial covenants.

At June 30, 2016 and December 31, 2015, we had $5.1 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 June 30, 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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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2016

(Unaudited)

The following tables summarize our outstanding derivative contracts as of June 30, 2016:

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Total |
|---|---|---|---|---|---|
| Oil Collars: | | | | | |
| 2016: | | | | | |
| Three-Way Collars WTI (1) | | | | | |
| Volume (Bbls) | — | — | 276,000 | 276,000 | 552,000 |
| Wtd Avg Price - Lower Floor | $ — | $ — | $ 40.00 | $ 40.00 | $ 40.00 |
| Wtd Avg Price - Upper Floor | $ — | $ — | $ 50.00 | $ 50.00 | $ 50.00 |
| Wtd Avg Price - Ceiling | $ — | $ — | $ 60.00 | $ 60.00 | $ 60.00 |
| Collars WTI (1) | | | | | |
| Volume (Bbls) | — | — | 828,000 | 828,000 | 1,656,000 |
| Wtd Avg Price - Floor | $ — | $ — | $ 39.17 | $ 39.17 | $ 39.17 |
| Wtd Avg Price - Ceiling | $ — | $ — | $ 47.92 | $ 47.92 | $ 47.92 |
| 2017: | | | | | |
| Collars WTI (1) | | | | | |
| Volume (Bbls) | 810,000 | 819,000 | 460,000 | — | 2,089,000 |
| Wtd Avg Price - Floor | $ 39.17 | $ 39.17 | $ 42.50 | $ — | $ 39.90 |
| Wtd Avg Price - Ceiling | $ 47.92 | $ 47.92 | $ 52.26 | $ — | $ 48.88 |

(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) | — | — | 5,520,000 | 5,520,000 | 11,040,000 |
| Wtd Avg Price - Floor | $ — | $ — | $ 2.28 | $ 2.28 | $ 2.28 |
| Wtd Avg Price - Ceiling | $ — | $ — | $ 2.82 | $ 2.82 | $ 2.82 |
| Perm EP (1) | | | | | |
| Volume (MMBtu) | — | — | 4,600,000 | 4,600,000 | 9,200,000 |
| Wtd Avg Price - Floor | $ — | $ — | $ 2.37 | $ 2.37 | $ 2.37 |

| | | | | | |
|---|---|---|---|---|---|
| Wtd Avg Price - Ceiling | $ — | $ — | $ 2.89 | $ 2.89 | $ 2.89 |
| 2017: | | | | | |
| PEPL (1) | | | | | |
| Volume (MMBtu) | 4,500,000 | 4,550,000 | 2,760,000 | — | 11,810,000 |
| Wtd Avg Price - Floor | $ 2.20 | $ 2.20 | $ 2.25 | $ — | $ 2.21 |
| Wtd Avg Price - Ceiling | $ 2.82 | $ 2.82 | $ 2.90 | $ — | $ 2.84 |
| Perm EP (1) | | | | | |
| Volume (MMBtu) | 4,500,000 | 4,550,000 | 1,840,000 | — | 10,890,000 |
| Wtd Avg Price - Floor | $ 2.37 | $ 2.37 | $ 2.30 | $ — | $ 2.36 |
| Wtd Avg Price - Ceiling | $ 2.95 | $ 2.95 | $ 2.93 | $ — | $ 2.95 |

(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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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2016

(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.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (in thousands) | 2016 | 2015 | 2016 | 2015 |
| (Gain) loss on derivative instruments, net | $ 33,236 | $ — | $ 32,808 | $ — |
| Settlement (gains) losses | $ (3,859) | $ — | $ (8,927) | $ — |

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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CIMAREX ENERGY CO.

Notes to Consolidated Financial Statements

June 30, 2016

(Unaudited)

The following tables present the amounts and classifications of our derivative assets and liabilities as of June 30, 2016 and December 31, 2015, as well as the potential effect of netting arrangements on contracts with the same counterparty.

June 30, 2016:

| (in thousands) | Balance Sheet Location | Asset | Liability |
|---|---|---|---|
| Oil contracts | Current assets — Derivative instruments | $ 1,119 | $ — |
| Oil contracts | Current liabilities — Derivative instruments | — | 17,720 |
| Natural gas contracts | Current liabilities — Derivative instruments | — | 10,679 |
| Oil contracts | Non-current liabilities — Other liabilities | — | 2,317 |
| Natural gas contracts | Non-current liabilities — Other liabilities | — | 892 |
| Total gross amounts presented in accompanying balance sheet | | 1,119 | 31,608 |
| Less: gross amounts not offset in the accompanying balance sheet | | (1,119) | (1,119) |
| Net amount: | | $ — | $ 30,489 |

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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(Unaudited)

The following table provides fair value measurement information for certain assets and liabilities as of June 30, 2016 and December 31, 2015:

| (in thousands) | June 30, 2016 Book Value | June 30, 2016 Fair Value | December 31, 2015 Book Value | December 31, 2015 Fair Value |
|---|---|---|---|---|
| Financial Assets (Liabilities): | | | | |
| 5.875% Notes due 2022 | $ (750,000) | $ (788,475) | $ (750,000) | $ (723,750) |
| 4.375% Notes due 2024 | $ (750,000) | $ (780,000) | $ (750,000) | $ (683,318) |
| Derivative instruments — assets | $ 1,119 | $ 1,119 | $ 11,246 | $ 11,246 |
| Derivative instruments — liabilities | $ (31,608) | $ (31,608) | $ — | $ — |

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 June 30, 2016 and December 31, 2015, the allowance for doubtful accounts was $1.6 million and $1.8 million, respectively.

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## 5.Capital Stock

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock.  At June 30, 2016, there were no shares of preferred stock outstanding.  A summary of our common stock activity for the six months ended June 30, 2016 follows:

| (in thousands) | |
|---|---|
| Issued and outstanding as of December 31, 2015 | 94,821 |
| Issuance of service-based restricted stock awards | 202 |
| Restricted stock forfeited and retired | (16) |
| Common stock reacquired and retired | (39) |
| Option exercises, net of cancellations | 19 |
| Issued and outstanding as of June 30, 2016 | 94,987 |

### Dividends

In May 2016, the Board of Directors declared a cash dividend of $0.08 per share.  The dividend is payable on September 1, 2016, to stockholders of record on August 15, 2016.  Dividends declared are recorded as a reduction of retained earnings to the extent retained earnings are available at the close of the period prior to the date of the declared dividend.  Dividends in excess of retained earnings are recorded as a reduction of additional paid-in capital.  For the dividends declared in May 2016, all of the dividends declared ($7.6 million) were recorded as a reduction of additional paid-in capital.  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.  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.

| | Three Months Ended | Six Months Ended |
|---|---|---|

| (in thousands) | June 30, 2016 | 2015 | June 30, 2016 | 2015 |
|---|---|---|---|---|
| Restricted stock awards | | | | |
| Performance stock awards | $ 7,215 | $ 4,645 | $ 12,909 | $ 9,643 |
| Service-based stock awards | 4,751 | 3,861 | 8,916 | 8,798 |
| | 11,966 | 8,506 | 21,825 | 18,441 |
| Stock option awards | 748 | 647 | 1,403 | 1,286 |
| Total stock compensation cost | 12,714 | 9,153 | 23,228 | 19,727 |
| Less amounts capitalized to oil and gas properties | (5,224) | (4,165) | (10,210) | (9,584) |
| Compensation expense | $ 7,490 | $ 4,988 | $ 13,018 | $ 10,143 |

During the second quarter of 2016, a voluntary Early Retirement Incentive Program (ERIP) was offered to certain employees and completed in June. In addition to those who participated in the ERIP, other individuals also retired in June. The retirement agreements included accelerated vesting of performance and service-based restricted stock awards and stock option awards. The effect of the accelerated vesting on our total stock compensation cost for the second quarter and six months ended June 30, 2016 was an increase of $2.6 million over the same periods from 2015.

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(Unaudited)

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 six months ended June 30, 2016:

| | | |
|---|---|---|
| (in thousands) | | |
| Asset retirement obligation at January 1, 2016 | $ | 164,105 |
| Liabilities incurred | | 1,502 |
| Liability settlements and disposals | | (6,210) |
| Accretion expense | | 3,806 |
| Revisions of estimated liabilities | | 2,496 |
| Asset retirement obligation at June 30, 2016 | | 165,699 |
| Less current obligation | | (9,033) |
| Long-term asset retirement obligation | $ | 156,666 |

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(Unaudited)

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 June 30, 2016 | Three Months Ended June 30, 2015 | Six Months Ended June 30, 2016 | Six Months Ended June 30, 2015 |
|---|---|---|---|---|
| Basic: | | | | |
| Net income (loss) | $ (270,290) | $ (600,215) | $ (456,421) | $ (1,015,156) |
| Participating securities’ share in earnings (1) | — | — | — | — |
| Net income (loss) applicable to common stockholders | $ (270,290) | $ (600,215) | $ (456,421) | $ (1,015,156) |
| | | | | |
| Diluted: | | | | |
| Net income (loss) | $ (270,290) | $ (600,215) | $ (456,421) | $ (1,015,156) |
| Participating securities’ share in earnings (1) | — | — | — | — |
| Net income (loss) applicable to common stockholders | $ (270,290) | $ (600,215) | $ (456,421) | $ (1,015,156) |
| | | | | |
| Shares: | | | | |
| Basic shares outstanding | 93,075 | 92,831 | 93,075 | 92,831 |
| Dilutive effect of stock options (2) | — | — | — | — |
| Fully diluted common stock | 93,075 | 92,831 | 93,075 | 92,831 |
| Excluded (2) | 2,279 | 1,931 | 2,279 | 1,931 |
| | | | | |
| Earnings (loss) per share to common stockholders (3): | | | | |
| Basic | $ (2.91) | $ (6.47) | $ (4.91) | $ (10.94) |
| Diluted | $ (2.91) | $ (6.47) | $ (4.91) | $ (10.94) |

(1) Participating securities are not included in undistributed earnings when a loss exists.
(2) Inclusion of certain shares would have an anti-dilutive effect.
(3) Earnings (loss) per share are based on actual figures rather than the rounded figures presented.

9.Income Taxes

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

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (in thousands) | 2016 | 2015 | 2016 | 2015 |
| Current taxes (benefit) | $ — | $ — | $ — | $ — |
| Deferred taxes (benefit) | (154,219) | (342,056) | (260,419) | (570,795) |
| | $ (154,219) | $ (342,056) | $ (260,419) | $ (570,795) |
| Combined Federal and State effective income tax rate | 36.3 % | 36.3 % | 36.3 % | 36.0 % |

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 June 30, 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 $222.4 million to finish drilling and completing wells in progress at June 30, 2016. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $3.8 million.

At June 30, 2016, we had firm sales contracts to deliver approximately 46.7 Bcf of natural gas over the next 28 months. If this gas is not delivered, our financial commitment would be approximately $116.9 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 $190.2 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 $12.5 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 $35.7 million. We anticipate meeting these obligations.

We have various commitments for office space and equipment under operating lease arrangements totaling $101.5 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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Notes to Consolidated Financial Statements

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(Unaudited)

11.Supplemental Disclosure of Cash Flow Information

| (in thousands) | Three Months Ended June 30, 2016 | Three Months Ended June 30, 2015 | Six Months Ended June 30, 2016 | Six Months Ended June 30, 2015 |
|---|---|---|---|---|
| Cash paid during the period for: | | | | |
| Interest expense (including capitalized amounts) | $ 39,140 | $ 39,277 | $ 39,734 | $ 40,212 |
| Interest capitalized | $ 9,917 | $ 16,583 | $ 10,057 | $ 16,997 |
| Income taxes | $ 2 | $ 555 | $ 13 | $ 556 |
| Cash received for income taxes | $ — | $ 109 | $ 25 | $ 409 |

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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 but have shown improvement during the second quarter of 2016. It is likely that oil prices will remain erratic due to the ongoing global supply and demand imbalance, high inventories and geopolitical factors.

Due to an imbalance between supply and demand across North America, prices for domestic natural gas and NGLs began to decline during the third quarter of 2014 and continued to be weak through the first quarter of 2016. While prices were stronger in the second quarter of 2016, future prices will likely continue to fluctuate.

Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production. For the first six months of 2016 our realized oil price fell 27% to $33.94 per Bbl from the same period of 2015. Similarly, our realized natural gas price dropped 29% to $1.87 per Mcf and our realized price for NGL declined 21% to $11.98 per Bbl. See Revenues below for further information regarding our realized commodity prices.

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, oversupply and high inventory storage levels could put downward pressure on commodity prices and 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 now estimated to be approximately $750 million, up from our previous expectation of $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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Summary of operating and financial results for the six months ended June 30, 2016 compared to the same period of 2015:

- Average production declined 1% to 973.7 MMcfe per day.
- Oil production declined by 16% to 45,267 barrels per day, gas volumes increased by 2% to 467.4 MMcf per day and NGL volumes rose 13% to 39,112 barrels per day.
- Production revenues declined 32% to $524.1 million.
- Cash on hand at June 30, 2016 was $641.7 million.
- Cash flow provided by operating activities declined 42% to $213.7 million.
- We incurred a net loss of $456.4 million ($4.91 per diluted share) versus a net loss of $1.02 billion ($10.94 per diluted share) in 2015.

In response to continued weak commodity prices we significantly reduced our 2016 exploration and development expenditures to $285.7 million compared to $470.5 million in 2015.

Total debt at June 30, 2016 and December 31, 2015 consisted of $1.5 billion of senior notes, with $750 million maturing in 2022 and $750 million maturing in 2024.

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 54% of our total production revenue for the first six months of 2016. Gas sales accounted for 30% and NGL sales contributed 16%. A $1.00 per barrel change in our realized oil price would have resulted in a $8.2 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $8.5 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $7.1 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 June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Oil Prices: | | | | |
| Average realized sales price ($/Bbl) | $ 40.07 | $ 50.66 | $ 33.94 | $ 46.79 |
| Average WTI Midland price ($/Bbl) | $ 45.42 | $ 57.36 | $ 39.83 | $ 52.01 |
| Average WTI Cushing price ($/Bbl) | $ 45.59 | $ 57.94 | $ 39.52 | $ 53.29 |
| | | | | |
| Gas Prices: | | | | |

| | | | | |
|---|---|---|---|---|
| Average realized sales price ($/Mcf) | $ 1.82 | $ 2.51 | $ 1.87 | $ 2.63 |
| Average Henry Hub price ($/Mcf) | $ 1.95 | $ 2.65 | $ 2.02 | $ 2.82 |
| | | | | |
| NGL Prices: | | | | |
| Average realized sales price ($/Bbl) | $ 13.93 | $ 14.67 | $ 11.98 | $ 15.15 |

During the first half of 2016 and 2015, approximately 79% and 85%, 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.

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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 ($2.4 billion, net of tax) for the year.  For the first quarter of 2016 we recognized a ceiling test impairment of $230.1 million ($146.2 million, net of tax).

At June 30, 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 $399.2 million ($253.6 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 June 30, 2016 ceiling calculation, based on the required trailing 12-month average prices, were $2.24 per Mcf of gas and $43.12 per barrel of oil.  To demonstrate the impact of commodity prices on the ceiling calculation, had average prices of $2.28 per Mcf of gas and $42.91 per barrel of oil been used instead, we would not have incurred any additional impairment for the second quarter of 2016.  The 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 July 2016 and the prices for July 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 and the first quarter of 2016 resulted in lower DD&A rates in each quarter following the impairment.

Production expense generally consists of costs for salt water disposal, labor, equipment, maintenance, 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 and Six Months Ended June 30, 2016 vs. June 30, 2015

In the second quarter of 2016, we had a net loss of $270.3 million ($2.91 per diluted share) compared to a net loss of $600.2 million ($6.47 per diluted share) for the same period of 2015. For the first six months of 2016, we had a net loss of $456.4 million ($4.91 per diluted share) down from a net loss of $1.02 billion ($10.94 per diluted share) in 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 2016 periods had lower production revenue than the same periods of 2015, this decrease was more than offset by lower impairment, DD&A and other operating costs in the 2016 periods. Period-over-period changes are discussed further in the analysis that follows.

| Production Revenue | | | Change Between 2016 / | Price/Volume Change | | |
|---|---|---|---|---|---|---|
| (in thousands or as indicated) | 2016 | 2015 | 2015 | Price | Volume | Total |
| For the Three Months Ended June 30: | | | | | | |
| Oil sales | $ 162,005 | $ 259,344 | (38) % | $ (42,815) | $ (54,524) | $ (97,339) |
| Gas sales | 76,615 | 106,374 | (28) % | (29,003) | (756) | (29,759) |
| NGL sales | 51,939 | 49,477 | 5 % | (2,758) | 5,220 | 2,462 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | $ 290,559 | $ 415,195 | (30) % | $ (74,576) | $ (50,060) | $ (124,636) |
| For the Six Months Ended June 30: | | | | | | |
| Oil sales | $ 279,578 | $ 455,349 | (39) % | $ (105,871) | $ (69,900) | $ (175,771) |
| Gas sales | 159,223 | 217,336 | (27) % | (64,652) | 6,539 | (58,113) |
| NGL sales | 85,291 | 95,077 | (10) % | (22,564) | 12,778 | (9,786) |
| | $ 524,092 | $ 767,762 | (32) % | $ (193,087) | $ (50,583) | $ (243,670) |

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The table below reflects our total production volumes.

| | For the Three Months Ended June 30, | | Change Between 2016 / 2015 | For the Six Months Ended June 30, | | Change Between 2016 / 2015 |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | | 2016 | 2015 | |
| Total oil volume — thousand barrels | 4,043 | 5,120 | (21) % | 8,239 | 9,731 | (15) % |
| Oil volume — barrels per day | 44,424 | 56,261 | (21) % | 45,267 | 53,765 | (16) % |
| Percent of total equivalent production | 28 % | 33 % | | 28 % | 33 % | |
| Average oil price — per barrel | $ 40.07 | $ 50.66 | (21) % | $ 33.94 | $ 46.79 | (27) % |
| Total gas volume — MMcf | 42,034 | 42,430 | (1) % | 85,068 | 82,555 | 3 % |
| Gas volume — MMcf per day | 461.9 | 466.3 | (1) % | 467.4 | 456.1 | 2 % |
| Percent of total equivalent production | 47 % | 45 % | | 48 % | 46 % | |
| Average gas price — per Mcf | $ 1.82 | $ 2.51 | (27) % | $ 1.87 | $ 2.63 | (29) % |
| Total NGL volume — thousand barrels | 3,727 | 3,373 | 10 % | 7,118 | 6,275 | 13 % |
| NGL volume — barrels per day | 40,961 | 37,070 | 10 % | 39,112 | 34,670 | 13 % |
| Percent of total equivalent production | 25 % | 22 % | | 24 % | 21 % | |
| Average NGL price — per barrel | $ 13.93 | $ 14.67 | (5) % | $ 11.98 | $ 15.15 | (21) % |
| Total equivalent production — MMcfe | 88,654 | 93,389 | (5) % | 177,210 | 178,595 | (1) % |
| Total equivalent production volumes — MMcfe/d | 974.2 | 1,026.2 | (5) % | 973.7 | 986.7 | (1) % |

As reflected in the table above, for the second quarter of 2016, our production revenues were 30% lower than those in the same period of 2015. In the second quarter of 2016, lower realized prices accounted for 60% of the $124.6 million quarter-over-quarter decline in production revenue. The remaining decrease resulted primarily from lower oil production in the second quarter of 2016.

Production revenues for the first six months of 2016 were 32% lower than the same period of 2015. Lower realized commodity prices accounted for 79% of the $243.7 million period-over-period decrease. The remaining $50.6 million decrease resulted as increased revenue from natural gas and NGL production was more than offset by lower revenue from oil production.

See Revenues above for a discussion regarding realized prices. The decreases in 2016 oil production were attributable to lower production from our Permian region. In the second quarter of 2016, lower oil production resulted from normal production declines, a slow-down in well completion activity and declines related to certain plant shut-ins. Production in the first six months of 2016 was also negatively impacted by capacity curtailments in the first quarter of 2016, 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 June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Oil (Bbls per day) | | | | |
| Permian Basin | 35,338 | 48,448 | 35,944 | 45,783 |
| Mid-Continent | 8,933 | 7,181 | 9,093 | 7,308 |
| Other | 153 | 632 | 230 | 674 |
| | 44,424 | 56,261 | 45,267 | 53,765 |
| Gas (MMcf per day) | | | | |
| Permian Basin | 181.2 | 189.4 | 177.4 | 170.0 |
| Mid-Continent | 279.1 | 270.2 | 288.7 | 278.6 |
| Other | 1.6 | 6.7 | 1.3 | 7.5 |
| | 461.9 | 466.3 | 467.4 | 456.1 |
| NGL (Bbls per day) | | | | |
| Permian Basin | 19,219 | 19,169 | 16,639 | 16,180 |
| Mid-Continent | 21,716 | 17,633 | 22,432 | 18,194 |
| Other | 26 | 268 | 41 | 296 |
| | 40,961 | 37,070 | 39,112 | 34,670 |
| Total Equivalent (MMcfe per day) | | | | |
| Permian Basin | 508.5 | 595.1 | 492.9 | 541.8 |
| Mid-Continent | 463.0 | 419.1 | 477.9 | 431.6 |
| Other | 2.7 | 12.0 | 2.9 | 13.3 |
| | 974.2 | 1,026.2 | 973.7 | 986.7 |

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 June 30, | | For the Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Gas Gathering and Marketing (in thousands): | | | | |
| Gas gathering and other revenues | $ 8,211 | $ 9,141 | $ 15,452 | $ 17,411 |
| Gas marketing revenues, net of related costs | $ 103 | $ (53) | $ (71) | $ 112 |

Fluctuations in revenues from gas gathering and gas marketing activities are a function of increases and decreases in volumes, commodity prices and gathering rate charges.

Analysis of Operating Costs and Expenses

Total operating costs and expenses for both the three and six months ended June 30, 2016 were 48% lower than those for the same periods of 2015. Most of the 2016 decreases resulted from lower ceiling test impairments 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.

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| | For the Three Months Ended June 30, | | Variance Between | Per Mcfe | |
|---|---|---|---|---|---|
| | 2016 | 2015 | 2016 / 2015 | 2016 | 2015 |
| Operating costs and expenses (in thousands, except per Mcfe): | | | | | |
| Impairment of oil and gas properties | $ 399,194 | $ 967,287 | $ (568,093) | N/A | N/A |
| DD&A | 123,877 | 217,451 | (93,574) | $ 1.40 | $ 2.33 |
| Asset retirement obligation | 1,750 | 2,042 | (292) | $ 0.02 | $ 0.02 |
| Production | 57,213 | 70,600 | (13,387) | $ 0.65 | $ 0.76 |
| Transportation, processing and other operating | 44,436 | 43,713 | 723 | $ 0.50 | $ 0.47 |
| Gas gathering and other | 7,492 | 11,306 | (3,814) | $ 0.09 | $ 0.12 |
| Taxes other than income | 14,066 | 25,980 | (11,914) | $ 0.16 | $ 0.28 |
| General and administrative | 21,424 | 14,054 | 7,370 | $ 0.24 | $ 0.15 |
| Stock compensation | 7,490 | 4,988 | 2,502 | $ 0.08 | $ 0.05 |
| (Gain) loss on derivative instruments, net | 33,236 | — | 33,236 | N/A | N/A |
| Other operating, net | 24 | 260 | (236) | N/A | N/A |
| | $ 710,202 | $ 1,357,681 | $ (647,479) | | |

| | For the Six Months Ended June 30, | | Variance Between | Per Mcfe | |
|---|---|---|---|---|---|
| | 2016 | 2015 | 2016 / 2015 | 2016 | 2015 |
| Operating costs and expenses (in thousands, except per Mcfe): | | | | | |
| Impairment of oil and gas properties | $ 629,326 | $ 1,570,886 | $ (941,560) | N/A | N/A |
| DD&A | 251,976 | 434,229 | (182,253) | $ 1.42 | $ 2.43 |
| Asset retirement obligation | 4,048 | 3,778 | 270 | $ 0.02 | $ 0.02 |
| Production | 127,915 | 152,811 | (24,896) | $ 0.72 | $ 0.86 |
| Transportation, processing and other operating | 90,879 | 83,355 | 7,524 | $ 0.51 | $ 0.47 |
| Gas gathering and other | 15,572 | 20,170 | (4,598) | $ 0.09 | $ 0.11 |
| Taxes other than income | 27,905 | 47,961 | (20,056) | $ 0.16 | $ 0.27 |
| General and administrative | 35,321 | 29,992 | 5,329 | $ 0.20 | $ 0.17 |
| Stock compensation | 13,018 | 10,143 | 2,875 | $ 0.07 | $ 0.06 |
| (Gain) loss on derivative instruments, net | 32,808 | — | 32,808 | N/A | N/A |
| Other operating, net | 114 | 784 | (670) | N/A | N/A |
| | $ 1,228,882 | $ 2,354,109 | $ (1,125,227) | | |

For the three and six months ended June 30, 2016, DD&A expense was 43% and 42% lower, respectively, compared to the same periods of 2015. The decreases were primarily due to lower DD&A rates in 2016. Impairments of our oil and gas properties during each quarter of 2015 and the first quarter of 2016 have 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 the remainder of 2016 to fluctuate depending on average realized prices and production volumes. 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.

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

| | For the Three Months Ended June 30, | | Variance Between 2016 / | Per Mcfe | |
|---|---|---|---|---|---|
| (in thousands, except per Mcfe) | 2016 | 2015 | 2015 | 2016 | 2015 |
| Lease operating expense | $ 46,952 | $ 61,509 | $ (14,557) | $ 0.53 | $ 0.66 |
| Workover expense | 10,261 | 9,091 | 1,170 | $ 0.12 | $ 0.10 |
| | $ 57,213 | $ 70,600 | $ (13,387) | $ 0.65 | $ 0.76 |

| | For the Six Months Ended June 30, | | Variance Between 2016 / | Per Mcfe | |
|---|---|---|---|---|---|
| (in thousands, except per Mcfe) | 2016 | 2015 | 2015 | 2016 | 2015 |
| Lease operating expense | $ 102,646 | $ 130,014 | $ (27,368) | $ 0.58 | $ 0.73 |
| Workover expense | 25,269 | 22,797 | 2,472 | $ 0.14 | $ 0.13 |
| | $ 127,915 | $ 152,811 | $ (24,896) | $ 0.72 | $ 0.86 |

Lease operating expense in the second quarter of 2016 declined 24% compared to the same quarter of 2015. Lease operating expense for the six months ended June 30, 2016 declined by 21% compared to the same period of 2015. The 2016 periods benefited from lower salt water disposal costs attributable to implementation of operational efficiencies. The 2016 periods also had reduced costs for rental equipment, labor and lower costs due to property divestitures.

For the three and six months ended June 30, 2016, workover expenses were 13% and 11% higher, respectively, than the same periods 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 second quarter of 2016 were relatively flat compared to the same period of 2015. For the first six months of 2016, these costs were 9% greater than the first six months of 2015. These costs will vary by product type and region. Approximately 12% of the increase in the first six months of 2016 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. The 2016 period-over-period decreases were primarily related to higher repair and maintenance activity in the 2015 periods.

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. During the three and six months ended June 30, 2016, these taxes decreased by 46% and 42%, respectively, compared to the same periods of 2015. The decreases were primarily a result of period-over-period declines in production revenue due to lower realized commodity prices.

G&A costs were as follows:

| (in thousands) | For the Three Months Ended June 30, 2016 | 2015 | Variance Between 2016 / 2015 | For the Six Months Ended June 30, 2016 | 2015 | Variance Between 2016 / 2015 |
|---|---|---|---|---|---|---|
| G&A capitalized to oil & gas properties | $ 17,973 | $ 17,824 | $ 149 | $ 34,135 | $ 34,055 | $ 80 |
| G&A expense | 21,424 | 14,054 | 7,370 | 35,321 | 29,992 | 5,329 |
| Total G&A cost | $ 39,397 | $ 31,878 | $ 7,519 | $ 69,456 | $ 64,047 | $ 5,409 |

During the second quarter of 2016, a voluntary Early Retirement Incentive Program (ERIP) was offered to certain employees and completed in June. Severance payments made to the participants in June resulted in higher G&A expense for the second quarter and first six months of 2016 compared to 2015. Going forward these departures are expected to result in lower G&A.

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G&A expense in the second quarter of 2016 was 52% higher than the same period of 2015. Approximately 65% of the increase resulted from the ERIP severance payments. The remaining increase resulted from an additional $3.6 million of incentive based compensation and other benefits which was partially offset by lower salaries of $1.4 million due to fewer employees quarter-over-quarter.

For the six months ended June 30, 2016, G&A expense exceeded that of the prior year by 18%. Severance payments associated with the ERIP accounted for approximately 89% of the increase. The rest of the increase resulted from higher incentive based compensation and other benefits which were mostly offset by lower consulting fees and other charges.

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 June 30, | | Variance Between 2016 / 2015 | For the Six Months Ended June 30, | | Variance Between 2016 / 2015 |
|---|---|---|---|---|---|---|
| (in thousands) | 2016 | 2015 | | 2016 | 2015 | |
| Restricted stock awards | | | | | | |
| Performance stock awards | $ 7,215 | $ 4,645 | $ 2,570 | $ 12,909 | $ 9,643 | $ 3,266 |
| Service-based stock awards | 4,751 | 3,861 | 890 | 8,916 | 8,798 | 118 |
| | 11,966 | 8,506 | 3,460 | 21,825 | 18,441 | 3,384 |
| Stock option awards | 748 | 647 | 101 | 1,403 | 1,286 | 117 |
| Total stock compensation cost | 12,714 | 9,153 | 3,561 | 23,228 | 19,727 | 3,501 |
| Less amounts capitalized | (5,224) | (4,165) | (1,059) | (10,210) | (9,584) | (626) |
| Stock compensation expense | $ 7,490 | $ 4,988 | $ 2,502 | $ 13,018 | $ 10,143 | $ 2,875 |

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, certain individuals retired in addition to those who participated in the ERIP described above in the G&A analysis. The retirement agreements included accelerated vesting of performance and service-based restricted stock awards and stock option awards. The accelerated vesting accounted for $2.0 million of the 2016 period-over-period increases in stock compensation expense.

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.

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 June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (in thousands) | 2016 | 2015 | 2016 | 2015 |
| (Gain) loss on derivative instruments, net | $ 33,236 | $ — | $ 32,808 | $ — |
| Settlement (gains) losses | $ (3,859) | $ — | $ (8,927) | $ — |

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Other (income) and expense

| (in thousands) | For the Three Months Ended June 30, 2016 | 2015 | Variance Between 2016 / 2015 | For the Six Months Ended June 30, 2016 | 2015 | Variance Between 2016 / 2015 |
|---|---|---|---|---|---|---|
| Interest expense | $ 20,824 | $ 21,297 | $ (473) | $ 41,629 | $ 42,553 | $ (924) |
| Capitalized interest | (5,633) | (8,570) | 2,937 | (10,537) | (17,987) | 7,450 |
| Other, net | (2,011) | (3,854) | 1,843 | (3,661) | (7,439) | 3,778 |
| | $ 13,180 | $ 8,873 | $ 4,307 | $ 27,431 | $ 17,127 | $ 10,304 |

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 three and six months ended June 30, 2016, capitalized interest decreased by 34% and 41%, respectively, compared to the same periods of 2015. The decreases were primarily due to lower average NPL costs in the 2016 periods.

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. For the three and six months ended June 30, 2016, Other, net decreased by 48% and 51%, respectively, compared to the same periods of 2015. The quarter-over-quarter decrease was primarily due to lower net gains from sales of oil and gas well equipment and supplies in 2016. The year-over-year decrease resulted from lower net gains from sales of oil and gas well equipment and supplies which were partially offset by higher interest income.

An analysis of our oil and gas well equipment and supplies was performed as of June 30, 2016 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 June 30, | Six Months Ended June 30, |
|---|---|---|

| (in thousands) | 2016 | 2015 | 2016 | 2015 |
|---|---|---|---|---|
| Current benefit | $ — | $ — | $ — | $ — |
| Deferred tax expense (benefit) | $ (154,219) | $ (342,056) | $ (260,419) | $ (570,795) |
| | $ (154,219) | $ (342,056) | $ (260,419) | $ (570,795) |
| Combined Federal and State effective income tax rate | 36.3 % | 36.3 % | 36.3 % | 36.0 % |

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.

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## 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 commodity prices.  Cash and cash equivalents at June 30, 2016 totaled $641.7 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 June 30, 2016 was 39% 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 $1.5 billion divided by the sum of long-term debt of $1.5 billion plus stockholders' equity of $2.3 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 six months of 2016 was $213.7 million, down 42% from $370.5 million in the same period of 2015.  The $156.8 million decrease resulted primarily from a period-over-period decrease in revenues, which was partially offset by net decreases in certain operating expenses and increased cash settlements of derivative instruments.    See RESULTS OF OPERATIONS above for information regarding the 2016 changes in revenue, operating expenses and derivative settlements.

For the first six months of 2016, net cash flow used for investing activities was $330.0 million, a decrease of $295.9 million (47%) from $625.9 million for the same period of 2015. In 2016, oil and gas and other capital expenditures were $292.3 million lower than the 2015 expenditures. In response to continued weak commodity prices we significantly reduced our 2016 oil and gas expenditures.

Net cash used in financing activities during the first six months of 2016 was $21.4 million, compared to net cash provided by financing activities of $706.3 million for the same period of 2015. In 2016, dividend payments of $22.7 million were offset by $1.3 million of proceeds from issuance of common stock from employee option exercises and other. In 2015, cash provided by financing activities included approximately $729.5 million of net

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proceeds from the sale of common stock and $4.9 million of proceeds from issuance of common stock from employee option exercises and other. The 2015 proceeds were partially offset by dividend payments of $28.1 million.

Reconciliation of Adjusted Cash Flow from Operations

| | Six Months Ended June 30, | |
|---|---|---|
| (in thousands) | 2016 | 2015 |
| Net cash provided by operating activities | $ 213,704 | $ 370,545 |
| Change in operating assets and liabilities | 14,751 | 68,758 |
| Adjusted cash flow from operations | $ 228,455 | $ 439,303 |

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 June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| (in thousands) | 2016 | 2015 | 2016 | 2015 |
| Acquisitions: | | | | |
| Proved | $ — | $ — | $ 3,324 | $ — |
| Unproved | — | 160 | 10,568 | 2,029 |
| Net purchase price adjustments (*) | 34 | (12,035) | (2,928) | (12,005) |
| | 34 | (11,875) | 10,964 | (9,976) |
| Exploration and development: | | | | |
| Land and seismic | 17,474 | 5,275 | 28,636 | 27,965 |
| Exploration and development | 138,686 | 184,999 | 285,708 | 470,526 |
| | 156,160 | 190,274 | 314,344 | 498,491 |
| Sales proceeds: | | | | |
| Proved | — | (1,129) | (12,500) | (2,399) |

| | | | | |
|---|---|---|---|---|
| Unproved | (16) | (6,211) | (16) | (6,211) |
| Net purchase price adjustments (*) | 357 | (31) | (114) | 94 |
| | 341 | (7,371) | (12,630) | (8,516) |
| | $ 156,535 | $ 171,028 | $ 312,678 | $ 479,999 |

(*) The net purchase price adjustments relate to activity in prior periods.

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 estimated to be approximately $750 million, up from our previous estimate of 650-$700 million. Our expectation is that 56% of our 2016 capital investment will be in the Permian Basin with the remainder in the Mid-Continent region.

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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. 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 June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| Gross wells | | | | |
| Permian Basin | 13 | 26 | 20 | 68 |
| Mid-Continent | 21 | 19 | 36 | 30 |
| | 34 | 45 | 56 | 98 |
| Net wells | | | | |
| Permian Basin | 9 | 18 | 12 | 48 |
| Mid-Continent | 5 | 6 | 7 | 9 |
| | 14 | 24 | 19 | 57 |

As of June 30, 2016, we had 100 gross wells awaiting completion: 26 Permian Basin and 74 Mid-Continent. We also had six operated rigs running: three in the Permian Basin and three 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 six months of 2016, our total assets decreased $711.5 million (14%) to $4.5 billion, compared to $5.2 billion at December 31, 2015. The decrease was mainly attributable to the $629.3 million of impairments to our oil and gas properties and a $137.6 million decrease in cash and cash equivalents.

Total liabilities declined by $260.6 million (11%) to $2.2 billion at June 30, 2016, compared to $2.4 billion at December 31, 2015. The decrease is primarily due to a $260.3 million decrease in deferred income taxes stemming from our net loss for the first six months of 2016.

Stockholders' equity totaled $2.3 billion at June 30, 2016, down 16% from $2.8 billion at December 31, 2015. The decrease was mainly attributable to our net loss of $456.4 million for the first six months of 2016.

The decreases in our total assets, liabilities and stockholders' equity and our net loss during the first six months of 2016 resulted primarily from the continued impact of lower realized commodity prices which resulted in lower production revenues and impairments of our oil and gas properties. See RESULTS OF OPERATIONS above for further information.

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Long-term Debt

Long-term debt at June 30, 2016 and December 31, 2015, consisted of the following:

| | June 30, 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 | $ 6,324 | $ 750,000 | $ 6,978 |
| 4.375% Senior Notes, due June 1, 2024 | 750,000 | 6,881 | 750,000 | 7,402 |
| Total long-term debt | $ 1,500,000 | $ 13,205 | $ 1,500,000 | $ 14,380 |

At June 30, 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 June 30, 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 six months of 2016. During the first six months of 2015 we had average daily bank debt outstanding of $55.2 thousand and the highest amount of bank borrowings outstanding during that period was $10.0 million, occurring in May.

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 June 30, 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 June 30, 2016.

Working Capital Analysis

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

At June 30, 2016, we had working capital of $514.3 million, a decrease of $153.6 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 $137.6 million.
- Net derivative instruments decreased by $38.0 million.
- Oil and gas well equipment and supplies decreased by $16.7 million.

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

- Operations-related accounts payable and accrued liabilities decreased by $25.2 million.
  - Accrued liabilities related to our E&D expenditures decreased by $10.0 million.
- Operations-related accounts receivable increased by $4.3 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. In May 2016, the Board of Directors declared a cash dividend of $0.08 per share. The dividend is payable on September 1, 2016 to stockholders of record on August 15, 2016. Future dividend payments will depend on our level of earnings, financing requirements, and other factors considered relevant by our Board of Directors.

Dividends declared are recorded as a reduction of retained earnings to the extent retained earnings are available at the close of the period prior to the date of the declared dividend. Dividends in excess of retained earnings are recorded as a reduction of additional paid-in capital. For the dividends declared in May 2016, all of the dividends declared ($7.6 million) were recorded as a reduction of additional paid-in capital.

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 June 30, 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 June 30, 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) | 526,875 | 76,876 | 153,750 | 153,750 | 142,499 |
| Operating leases | 101,488 | 9,435 | 20,927 | 21,426 | 49,700 |
| Drilling commitments (2) | 226,177 | 226,177 | — | — | — |
| Asset retirement obligation (3) | 165,699 | 9,033 | — (3) | — (3) | — (3) |

| | | | | | |
|---|---|---|---|---|---|
| Other liabilities (4) | 159,809 | 69,024 | 60,983 | 2,823 | 26,979 |
| Firm transportation | 29,150 | 7,030 | 8,827 | 4,427 | 8,866 |

(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 $222.4 million consisting of obligations to finish drilling and completing wells in progress at June 30, 2016. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $3.8 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, the fair value of our liabilities associated with our derivative contracts and other miscellaneous commitments.

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At June 30, 2016, we had firm sales contracts to deliver approximately 46.7 Bcf of natural gas over the next 28 months. If this gas is not delivered, our financial commitment would be approximately $116.9 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 $190.2 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 $12.5 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 $35.7 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 54% of our total production revenue for the first six months of 2016. Gas sales accounted for 30% and NGL sales contributed 16%. A $1.00 per barrel change in our realized oil price would have resulted in a $8.2 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $8.5 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $7.1 million.

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We periodically enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production. At June 30, 2016, we have gas collars in place for the years 2016 and 2017 with a net total fair value liability of $11.6 million. We have oil collars in place for the years 2016 and 2017 with a net total fair value liability of $18.9 million. 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 $4.3 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 $4.3 million in our gain (loss) on mark-to-market derivatives in 2016.

Interest Rate Risk

At June 30, 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 June 30, 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 June 30, 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

| | |
|---|---|
| 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.

August 4, 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)