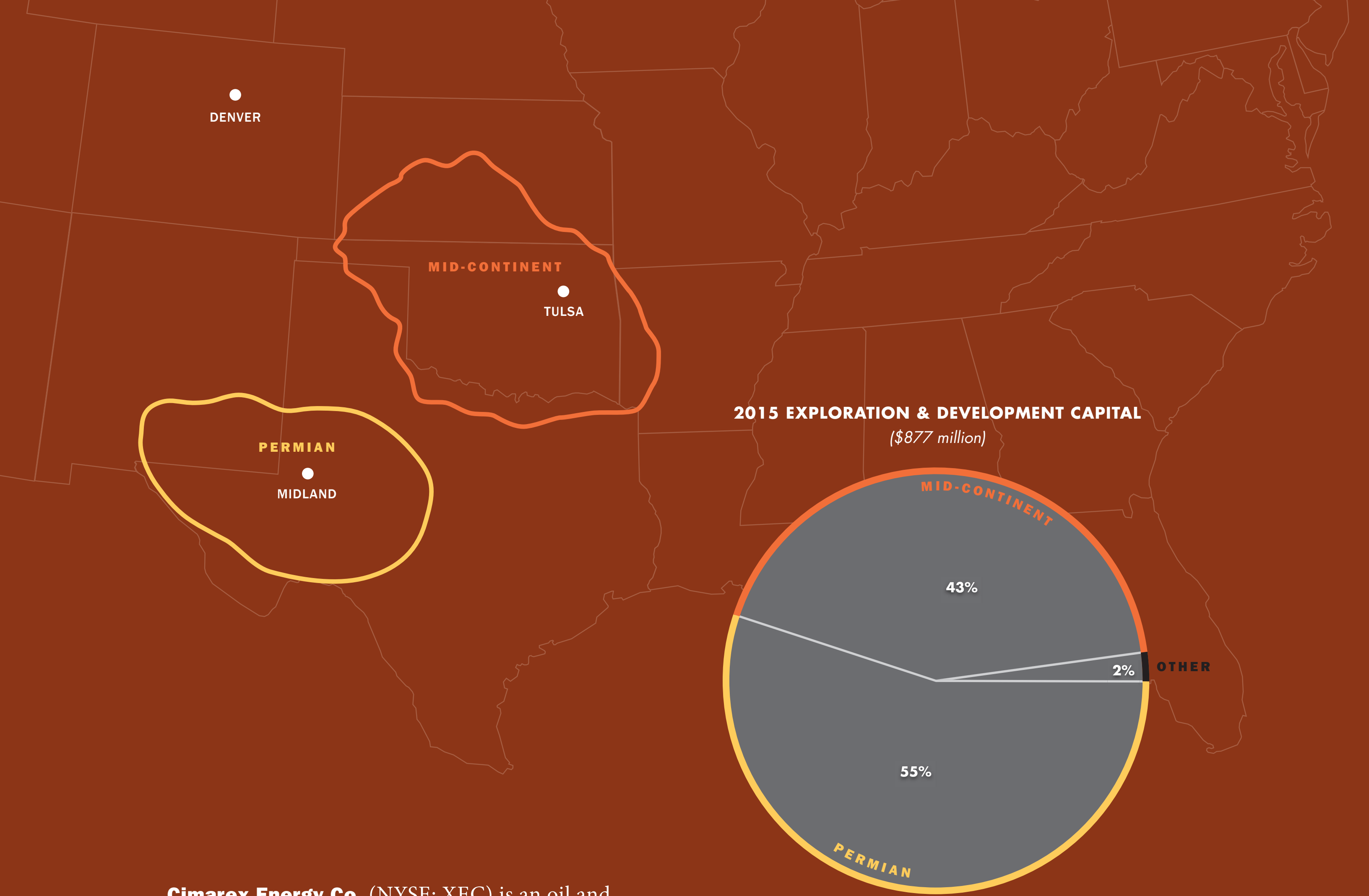
IDEAS

# *Strategies for Good Times and Bad*

*Value*

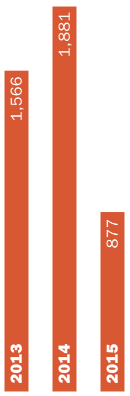
ANNUAL REPORT 2015

RETURNS

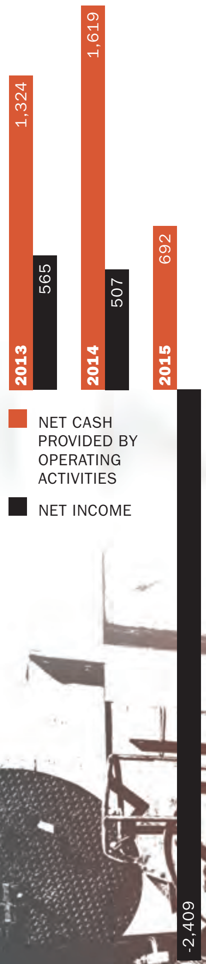



**Cimarex Energy Co.** (NYSE: XEC) is an oil and gas exploration and production company with operations mainly located in Oklahoma, Texas and New Mexico. We pride ourselves on having strong technical teams with the common goal of adding shareholder value through drilling and production. The cornerstone to our approach is detailed pre- and post-drill economic evaluation of after-tax rate-of-return on invested capital. We continually strive to maximize our cash flow from producing properties for reinvestment in growth opportunities.

**_EXPLORATION AND DEVELOPMENT CAPITAL INVESTMENT_**
*(Millions of Dollars)*




**_NET INCOME AND CASH FLOW_**
*(Millions of Dollars)*




# *Performance Summary*

| | YEAR ENDED DECEMBER 31, | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| **FINANCIAL** *(In millions, except per share data)* | | | |
| Oil, gas & NGL sales | $1,417.5 | $2,372.8 | $1,952.5 |
| Net income (loss) | (2,408.9) | 507.2 | 564.7 |
| Net income (loss) per diluted share | (25.92) | 5.78 | 6.47 |
| Net cash provided by operating activities | 691.5 | 1,619.4 | 1,324.3 |
| Capital investment: | | | |
| Exploration and development | 877.0 | 1,881.0 | 1,565.5 |
| Acquisition | (5.0)* | 249.7 | 37.1 |
| | 872.0 | 2,130.7 | 1,602.6 |

| | DECEMBER 31, | | |
|---|---|---|---|
| | **2015** | **2014** | **2013** |
| Total assets | 5,243.3 | 8,708.5 | 7,243.3 |
| Debt (principal) | 1,500.0 | 1,500.0 | 924.0 |
| Stockholders' equity | 2,797.7 | 4,500.6 | 4,022.2 |

**Includes purchase price adjustments.*

| | **2015** | **2014** | **2013** |
|---|---|---|---|
| **OPERATIONAL** | | | |
| Proved reserves: | | | |
| Oil (MMBbls) | 107.8 | 119.0 | 108.5 |
| NGL (MMBbls) | 124.3 | 125.3 | 92.0 |
| Gas (Bcf) | 1,517.0 | 1,666.7 | 1,293.5 |
| Total (Bcfe) | 2,909.4 | 3,132.3 | 2,497.0 |
| Proved developed (Bcfe) | 2,189.9 | 2,402.0 | 1,995.2 |
| Daily production: | | | |
| Oil (Bbls) | 51,132 | 42,846 | 36,659 |
| NGL (Bbls) | 35,789 | 31,078 | 21,578 |
| Gas (MMcf) | 463.0 | 425.0 | 343.1 |
| Total (MMcfe) | 984.5 | 868.6 | 692.6 |
| Realized price: | | | |
| Oil (per Bbl) | $ 43.38 | $ 83.70 | $ 93.44 |
| NGL (per Bbl) | $ 13.75 | $ 33.14 | $ 29.36 |
| Gas (per Mcf) | $ 2.53 | $ 4.43 | $ 3.76 |

# Fellow Shareholders

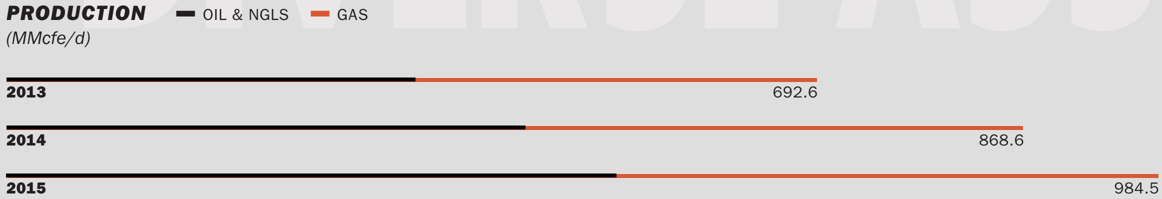
It has been a challenging year. When I wrote to you in March 2015, WTI crude oil was trading at $50 per barrel and natural gas was trading at $2.68 per Mcf. As I write to you today, oil is selling for $33.53 per barrel and natural gas now trades at $1.73 per Mcf. We thought we were facing a headwind. It turned out to be a hurricane.

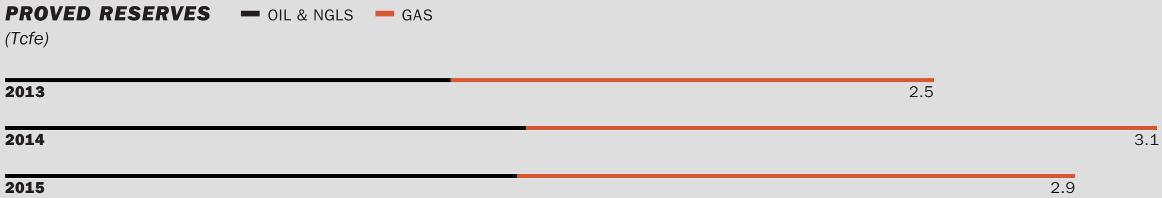
We entered 2015 with strong operational momentum, with 22 rigs deployed. By May our rig count was reduced to six. Ultimately, we invested $877 million on exploration and development during 2015, a significant reduction from the $1.9 billion invested in 2014. Cimarex was able to grow production thirteen percent in 2015, a testament to the quality of our opportunity set. But the deterioration in prices caused total proved reserves to decline from 3.1 to 2.9 trillion cubic feet equivalent. Had it not been for the negative price revision of .4 Tcfe, reserves would have reached another high watermark for Cimarex.

the size and scope of the Cimarex property base and can manage accordingly.

We have never been more bullish on our assets and the quality of our drilling inventory. Our core assets in the Delaware Basin and Meramec/Woodford plays in the Anadarko Basin are top tier. We are pleased with our well results and associated returns. Delaware Basin Wolfcamp well performance continues to improve and we believe there is room to achieve further performance improvements. Our multi-basin approach allows us to leverage new ideas and innovations from each basin and apply it to the other. We are positioned to capitalize on the technology arbitrage between basins. In both the Delaware Basin and the Meramec/Woodford plays, long horizontal wells are an increasingly important part of our strategy and our acreage in both basins is well configured to allow for them. We have manageable lease expirations and we will preserve our prime acreage.

DIVERSE ASSETS




We are adapting to this environment. Over the past two years, we have put a lot of energy into long range planning, including detailed iterations on future swings in commodity prices, future capital investments, and associated future production. This proved extremely useful in the tumultuous commodity price environment we experienced in 2015 and continue to experience today. We scrubbed our assets so that we can more fully understand

The challenge before us is to preserve our assets, our balance sheet, and our organization so that shareholders of Cimarex will fully benefit from a future recovery. We don't have any special insight on when or how commodity prices will recover. We do know that we will probably be as surprised by the recovery as we were by the collapse. When prices recover, Cimarex will be ready and will be stronger having risen to the challenge.

*innovation*

Our core strengths continue to be idea generation and innovation. Our teams are hard at work developing new plays and new concepts. We have faced challenges in the past. In 2009, the financial crisis caused an extraordinary drop in commodity prices so we reduced our activity level from 43 operated rigs to three. We then challenged our organization to be innovative and creative to find ways to make a living in the downturn. We were not victims. That year we developed plays that would carry us in the ensuing years, and are still among our core programs today. Our challenge in 2016 is do it again. Fortunately we have an organization that is ready to face these challenges, however difficult they may be. We will remain disciplined and preserve our assets and the deep inventory that is our future. We will also seek to build new things and to take advantage of this downturn. No one is hanging their head at Cimarex. We are hard at work to control our own destiny. Fully burdened rate-of-return focused investment is our rudder in capital investment decisions and activity levels. It is a core belief that our focus on rate-of-return provides us the clearest path forward in creating shareholder value. We measure ourselves objectively, look back on prior years' programs, and strive to learn lessons along the way. Our experience in navigating past downturns gives us confidence that we will see our way through this one.

We live in extraordinary times. World energy markets have been turned upside down by changing supply-demand dynamics. International relationships are being reset in ways that are redefining long standing strategic partnerships and trade cooperatives. The world is as volatile as ever, and increasing security threats have the potential to change the energy dynamic overnight.

We remain optimistic. The world needs energy. The growing demand for electrification, refrigeration, transportation, heating, and cooling are inevitable as the world modernizes. We celebrate this and are proud to be part of an industry that provides the opportunity for a better life through affordable, abundant energy.

Despite the challenges, we love this business. Cimarex has a hard-working, dedicated staff that is second to none. Our Board of Directors understands our business, shares our values and shares our pride in what we are building. Cimarex has long term owners that have supported us through the cycles and offer us their perspectives and their wisdom. We will continue to honor these relationships, to work valiantly for the sake of our owners, our organization and the communities within which we operate.

There will be better days in our industry. Until then, we will continue to distinguish ourselves as a premier player. Thank you for your support. We never forget our purpose.

Sincerely,

Thomas E. Jorden
*Chief Executive Officer, President and Chairman of the Board*
March 2, 2016

ABILITY TO ADAPT

# Board of Directors

**THOMAS E. JORDEN** – CHAIRMAN

**JOSEPH R. ALBI**

**HANS HELMERICH** (**) (***)

**DAVID A. HENTSCHEL** (**) (***)

**HAROLD R. LOGAN, JR.** – LEAD DIRECTOR (*) (***)

**FLOYD R. PRICE** (**) (***)

**MONROE W. ROBERTSON** (*) (***)

**LISA A. STEWART** (*) (***)

**MICHAEL J. SULLIVAN** (*) (***)

**L. PAUL TEAGUE** (**) (***)

* MEMBER OF THE AUDIT COMMITTEE
** MEMBER OF THE COMPENSATION AND GOVERNANCE COMMITTEE
*** MEMBER OF THE NOMINATING COMMITTEE

## Corporate Management

THOMAS E. JORDEN
*CHIEF EXECUTIVE OFFICER, PRESIDENT AND CHAIRMAN OF THE BOARD*

JOSEPH R. ALBI
*EXECUTIVE VICE PRESIDENT – OPERATIONS, CHIEF OPERATING OFFICER*

G. MARK BURFORD
*VICE PRESIDENT – CHIEF FINANCIAL OFFICER*

STEPHEN P. BELL
*EXECUTIVE VICE PRESIDENT – BUSINESS DEVELOPMENT*

FRANCIS B. BARRON
*SENIOR VICE PRESIDENT – GENERAL COUNSEL, CORPORATE SECRETARY*

JOHN LAMBUTH
*SENIOR VICE PRESIDENT – EXPLORATION*

GARY R. ABBOTT
*VICE PRESIDENT – CORPORATE ENGINEERING*

RICHARD S. DINKINS
*VICE PRESIDENT – HUMAN RESOURCES*

KRISTA L. JOHNSON
*VICE PRESIDENT – GOVERNMENTAL AND EXTERNAL AFFAIRS*

JAMES H. SHONSEY
*VICE PRESIDENT – CONTROLLER, CHIEF ACCOUNTING OFFICER*

## Exploration Management

ROGER G. ALEXANDER
*VICE PRESIDENT – PERMIAN BASIN*

EDWARD J. FETKOVICH
*REGIONAL EXPLORATION MANAGER – MID-CONTINENT*

MARK HOLLAND
*MANAGER – NEW VENTURES EXPLORATION*

## Operations Management

WAYNE C. CHANG
*VICE PRESIDENT – MARKETING AND MIDSTREAM*

THOMAS F. McCOY
*VICE PRESIDENT – PRODUCTION*

STEVEN J. SIMONTON
*VICE PRESIDENT – DRILLING AND COMPLETION OPERATIONS*

**Investor Contact**
KAREN ACIERNO
*DIRECTOR – INVESTOR RELATIONS*

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D C 20549**

## Form 10-K

**(Mark One)**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the fiscal year ended December 31, 2015**
**OR**
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**Commission file number 001-31446**

## CIMAREX ENERGY CO.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **45-0466694** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**1700 Lincoln Street, Suite 3700, Denver, Colorado 80203**
(Address of principal executive offices including ZIP code)

**(303) 295-3995**
(Registrant's telephone number)

Securities Registered Pursuant to Section 12(b) of the Act:

| Title of Each Class | Name of each exchange on which registered |
|---|---|
| Common Stock ($0.01 par value) | New York Stock Exchange |

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☒ NO ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☒

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 Act). YES ☐ NO ☒

Aggregate market value of the voting stock held by non-affiliates of Cimarex Energy Co. as of June 30, 2015 was approximately $10.2 billion.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 12, 2016 was 94,819,854. Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2016 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

**TABLE OF CONTENTS**
**DESCRIPTION**

## 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

**GAAP**—Generally accepted accounting principles in the U.S.

**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

**PUD**—Proved undeveloped

**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*

## PART I

### Cautionary Information about Forward-Looking Statements

Throughout this Form 10-K, we make statements that may be deemed "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. In particular, in our Management's Discussion and Analysis of Financial Condition and Results of Operations, we are providing "*2016 Outlook,*" which contains projections for certain 2016 operational activities. All statements, other than statements of historical facts, that address activities, events, outcomes and other matters that Cimarex plans, expects, intends, assumes, believes, budgets, predicts, forecasts, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10- K. Forward-looking statements include statements with respect to, among other things:

- Fluctuations in the price we receive for our oil and gas production;
- Timing and amount of future production of oil and natural gas;
- Reductions in the quantity of oil and gas sold due to decreased industrywide demand and/or curtailments in production from specific properties or areas due to mechanical, transportation, marketing, weather or other problems;
- Reserve estimates;
- Cash flow and anticipated liquidity;
- Amount, nature and timing of capital expenditures;
- Access to capital markets;
- Legislation and regulatory changes;
- Operating costs and other expenses;
- 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;
- Exploration and development opportunities that we pursue may not result in economic, productive oil and gas properties;
- Drilling of wells;
- Estimates of proved reserves, exploitation potential or exploration prospect size;
- Increased financing costs due to a significant increase in interest rates;
- De-risking of acreage.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and gas. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures and other risks described herein.

Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of such data by our engineers. As a result, estimates made by different engineers often vary from one another. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the timing of future production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K cause our underlying assumptions to be incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, express or implied, included in this Form 10-K and attributable to Cimarex are qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that Cimarex or persons acting on its behalf may issue. Cimarex does not undertake any obligation to update any forward-looking statements to reflect events or circumstances after the date of filing this Form 10-K with the Securities and Exchange Commission, except as required by law.

## ITEMS 1 AND 2. BUSINESS AND PROPERTIES

### *General*

Cimarex Energy Co., a Delaware corporation formed in 2002, is an independent oil and gas exploration and production company. Our operations are located mainly in Oklahoma, Texas and New Mexico. On our website -- www.cimarex.com -- you will find our annual reports, proxy statements and all of our Securities and Exchange Commission (SEC) filings. Throughout this Form 10-K we use the terms "Cimarex," "company," "we," "our," and "us" to refer to Cimarex Energy Co. and its subsidiaries.

Our principal business objective is to profitably grow proved reserves and production for the long-term benefit of our shareholders. Our strategy centers on maximizing cash flow from producing properties to reinvest in exploration and development opportunities. We consider merger and acquisition opportunities that enhance our competitive position and we occasionally divest non-core assets. Key elements to our approach include:

- Maintaining a strong financial position
- Investment in a diversified portfolio of drilling opportunities with varying geologic characteristics, in different geographic areas and with assorted exposure to oil, natural gas and NGLs
- Detailed evaluation and ranking of investment decisions based on rate of return
- Tracking predicted versus actual results in a centralized exploration management system, providing feedback to improve results
- Attracting quality employees and maintaining integrated teams of geoscientists, landmen and engineers
- Maximizing profitability by efficiently operating our properties

Conservative use of leverage has long been the key to our financial strategy. We believe that low leverage and our full-cycle returns mitigate financial risk, which enables us to better withstand volatility in commodity prices and provide competitive returns to shareholders. See Item 5 Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities – Stock Performance Graph and Item 6 Selected Financial Data for additional financial and operating information for fiscal years 2011 – 2015.

### *Proved Oil and Gas Reserves*

Our total proved reserves declined 7% to 2.9 Tcfe in 2015, largely as a result of 399 Bcfe of negative price related revisions. Proved undeveloped reserves as a percentage of total proved reserves increased to 25% from 23% a year ago. We added 571 Bcfe of new reserves through extensions and discoveries and net positive performance revisions, replacing 159% of production. The change in our proved reserves is as follows (in Bcfe):

| | |
|---|---|
| Reserves at December 31, 2014 | 3,132.3 |
| Revisions of previous estimates | (276.2) |
| Extensions and discoveries | 428.7 |
| Purchases of reserves | — |
| Production | (359.3) |
| Sales of reserves | (16.1) |
| Reserves at December 31, 2015 | 2,909.4 |

Revisions of previous estimates in the above table include negative commodity price and operating cost related revisions of 399 and 19 Bcfe, respectively, partially offset by net positive performance revisions of 142 Bcfe.

A breakdown by commodity of our proved oil and gas reserves follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Total Proved Reserves: | | | |
| Gas (Bcf) | 1,517.0 | 1,666.7 | 1,293.5 |
| Oil (MMBbls) | 107.8 | 119.0 | 108.5 |
| NGL (MMBbls) | 124.3 | 125.3 | 92.0 |
| Equivalent (Bcfe) | 2,909.4 | 3,132.3 | 2,497.0 |
| % Developed | 75 | 77 | 80 |

See "Supplemental Oil and Gas Information" in Item 8 of this report for further information.

Production volumes totaled 985 MMcfe of natural gas equivalent per day, a 13% increase over 2014. Production volumes are comprised of 47% natural gas, 31% oil and 22% NGLs. The following tables show our production volumes by region, the average commodity prices received and production cost per unit of production (Mcfe). Separate data also is included for our Cana-Woodford project, which is part of our Mid-Continent region and is part of our largest producing field.

| | Production Volumes | | | | Net Average Daily Volumes | | | |
|---|---|---|---|---|---|---|---|---|
| Years Ended December 31, | Gas (MMcf) | Oil (MBbls) | NGL (MBbls) | Equivalent (MMcfe) | Gas (MMcf) | Oil (MBbls) | NGL (MBbls) | Equivalent (MMcfe) |
| **2015** | | | | | | | | |
| Permian Basin | 66,006 | 15,719 | 6,220 | 197,644 | 180.8 | 43.1 | 17.0 | 541.5 |
| Mid-Continent | 100,801 | 2,746 | 6,757 | 157,821 | 276.2 | 7.5 | 18.5 | 432.4 |
| Other | 2,180 | 198 | 86 | 3,878 | 6.0 | 0.5 | 0.3 | 10.6 |
| Total Company | 168,987 | 18,663 | 13,063 | 359,343 | 463.0 | 51.1 | 35.8 | 984.5 |
| Cana-Woodford | 77,882 | 2,206 | 5,957 | 126,865 | 213.4 | 6.0 | 16.3 | 347.6 |
| **2014** | | | | | | | | |
| Permian Basin | 45,200 | 12,552 | 4,187 | 145,636 | 123.8 | 34.4 | 11.5 | 399.0 |
| Mid-Continent | 106,711 | 2,682 | 6,980 | 164,682 | 292.4 | 7.3 | 19.1 | 451.2 |
| Other | 3,217 | 405 | 176 | 6,704 | 8.8 | 1.1 | 0.5 | 18.4 |
| Total Company | 155,128 | 15,639 | 11,343 | 317,022 | 425.0 | 42.8 | 31.1 | 868.6 |
| Cana-Woodford | 76,915 | 1,903 | 5,937 | 123,952 | 210.7 | 5.2 | 16.3 | 339.6 |
| **2013** | | | | | | | | |
| Permian Basin | 35,414 | 10,739 | 2,823 | 116,783 | 97.0 | 29.4 | 7.7 | 320.0 |
| Mid-Continent | 84,779 | 2,171 | 4,757 | 126,345 | 232.3 | 5.9 | 13.0 | 346.1 |
| Other | 5,055 | 470 | 296 | 9,659 | 13.8 | 1.4 | 0.9 | 26.5 |
| Total Company | 125,248 | 13,380 | 7,876 | 252,787 | 343.1 | 36.7 | 21.6 | 692.6 |
| Cana-Woodford | 50,919 | 1,150 | 3,863 | 81,000 | 139.5 | 3.2 | 10.6 | 221.9 |

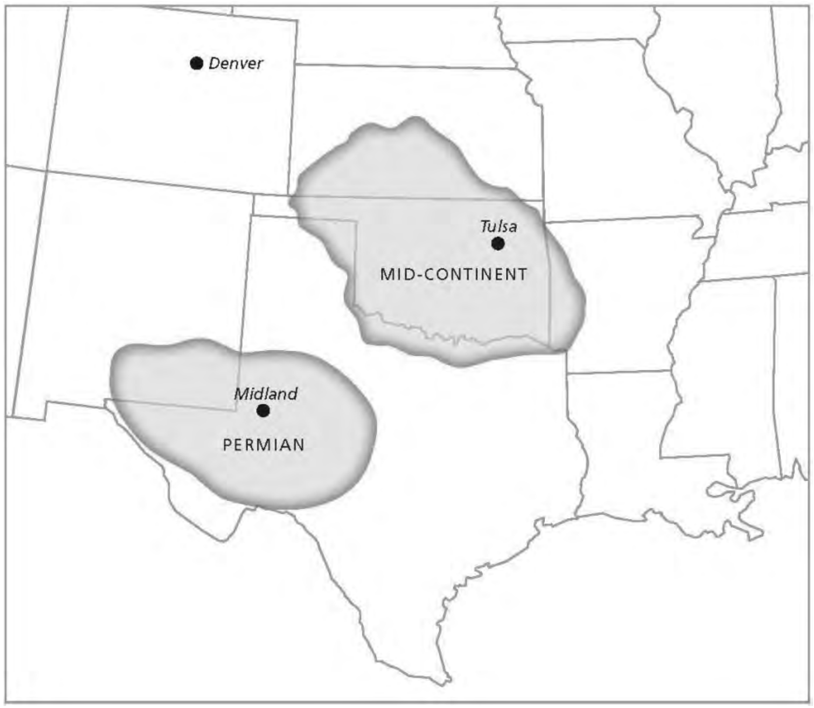
| Years Ended December 31, | Average Realized Price Gas (per Mcf) | Oil (per Bbl) | NGL (per Bbl) | Production Cost (per Mcfe) |
|---|---|---|---|---|
| **2015** | | | | |
| Permian Basin | $ 2.55 | $ 43.58 | $ 11.94 | $ 1.06 |
| Mid-Continent | $ 2.51 | $ 41.90 | $ 15.41 | $ 0.52 |
| Other | $ 3.16 | $ 48.01 | $ 14.72 | $ 1.72 |
| Total Company | $ 2.53 | $ 43.38 | $ 13.75 | $ 0.83 |
| Cana-Woodford | $ 2.51 | $ 41.54 | $ 15.59 | $ 0.26 |
| **2014** | | | | |
| Permian Basin | $ 4.48 | $ 82.44 | $ 30.04 | $ 1.58 |
| Mid-Continent | $ 4.42 | $ 88.23 | $ 35.03 | $ 0.58 |
| Other | $ 4.40 | $ 92.82 | $ 32.09 | $ 2.31 |
| Total Company | $ 4.43 | $ 83.70 | $ 33.14 | $ 1.08 |
| Cana-Woodford | $ 4.32 | $ 88.21 | $ 34.89 | $ 0.24 |
| **2013** | | | | |
| Permian Basin | $ 3.91 | $ 93.02 | $ 26.13 | $ 1.48 |
| Mid-Continent | $ 3.70 | $ 93.48 | $ 31.25 | $ 0.76 |
| Other | $ 3.74 | $ 102.67 | $ 29.81 | $ 1.85 |
| Total Company | $ 3.76 | $ 93.44 | $ 29.36 | $ 1.13 |
| Cana-Woodford | $ 3.57 | $ 94.33 | $ 30.64 | $ 0.27 |

***Acquisitions and Divestitures***

In 2015 we sold interests in various non-core oil and gas properties for $41 million. Cimarex made no material property acquisitions in 2015.

***Exploration and Production Overview***

Cimarex has one reportable segment, exploration and production (E&P). Our E&P activities take place primarily in two areas: the Permian Basin and the Mid-Continent region. Almost all of our exploration and development (E&D) capital is allocated between these two areas. In 2015, E&D investment totaled $877 million. Of that, 55% was invested in the Permian Basin and 43% in the Mid-Continent region.




In 2015, Cimarex drilled or participated in 219 gross (99 net) wells, of which we operated 123 gross (81.9 net) wells. At year-end, we were in the process of drilling or participating in 20 gross (9.9 net) wells and there were 49 gross (20 net) wells waiting on completion. A summary of our 2015 exploration and development activity by region is as follows:

| | E&D Capital (in millions) | Gross Wells Drilled | Net Wells Drilled | % Completed As Producers |
|---|---|---|---|---|
| Permian Basin | $ 482 | 85 | 60 | 99 |
| Mid-Continent | 381 | 134 | 39 | 99 |
| Other | 14 | — | — | — |
| | $ 877 | 219 | 99 | 99 |

The Permian region encompasses west Texas and southeast New Mexico. Cimarex's Permian Basin efforts are located in the western half of the Permian Basin known as the Delaware Basin. In 2015, we focused on drilling horizontal wells that yielded oil and liquids-rich gas from the Wolfcamp shale, the Bone Spring formation, and the Avalon shale. Cimarex saw improved results in its Wolfcamp shale wells, as measured by production and reserves, with the implementation of long laterals and continued improvement in well completion design and in the Bone Spring wells via upsized well completions.

The Permian region produced 542 MMcfe per day in 2015, which was 55% of our total company production. Oil production in the Permian Basin in 2015 averaged a record 43,067 barrels per day, a 25% increase over 2014.

Our Mid-Continent region consists of Oklahoma and the Texas Panhandle. Our activity in 2015 in the Mid-Continent was focused in the Cana-Woodford shale and the Meramec horizon, both in Oklahoma. We continued to implement larger well completions in the Cana-Woodford shale that were highly successful in 2014. We applied those same techniques to delineate the Meramec horizon, located above the Woodford. Cimarex continues to evaluate the size and potential of the Meramec play.

During 2015, production from the Mid-Continent averaged 432 MMcfe per day, or 44% of total company production. Due to the timing of well completions, production from the region decreased 4% in 2015 versus 2014.

***Wells Drilled***

We drilled the following exploratory and developmental wells in 2015:

| | Wells Drilled | | | | | |
|---|---|---|---|---|---|---|
| | 2015 | | 2014 | | 2013 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Exploratory | | | | | | |
| Productive | — | — | 1 | 0.4 | 1 | 1.0 |
| Dry | — | — | 1 | 0.5 | 3 | 2.4 |
| Total | — | — | 2 | 0.9 | 4 | 3.4 |
| Developmental | | | | | | |
| Productive | 219 | 98.7 | 309 | 173.6 | 359 | 181.0 |
| Dry | 3 | 1.7 | 1 | 0.1 | 2 | 1.0 |
| Total | 222 | 100.4 | 310 | 173.7 | 361 | 182.0 |

We have working interests in the following productive wells by region as of December 31, 2015:

| | Gas | | Oil | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| Mid-Continent | 3,766 | 1,447 | 494 | 165 |
| Permian Basin | 998 | 500 | 4,962 | 1,025 |
| Other | 106 | 11 | 22 | 5 |
| | 4,870 | 1,958 | 5,478 | 1,195 |

***Significant Properties***

All of our oil and gas assets (proved reserves and undeveloped acreage) are located in the United States. We have varying levels of ownership interests in our properties consisting of working, royalty and overriding royalty interests. We operate the wells that comprise 76% of our proved reserves. In 2015, proved reserves in the Watonga-Chickasha field were approximately 56% of the company's total proved reserves. The Cana-Woodford shale makes up the majority of this field. No other field had reserves in excess of 15% of our total proved reserves.

At December 31, 2015, 63% of our total proved reserves were located in the Mid-Continent region and 37% were in the Permian Basin. We owned an interest in 10,348 gross (3,153 net) productive oil and gas wells. The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2015.

| | Gas (Bcf) | Oil (MMBbl) | NGL (MMBbl) | Equivalent (Bcfe) | % of Total Proved Reserves |
|---|---|---|---|---|---|
| Mid-Continent | 1,134.4 | 29.0 | 87.6 | 1,834.6 | 63 |
| Permian Basin | 378.5 | 78.5 | 36.6 | 1,069.0 | 37 |
| Other | 4.1 | 0.3 | 0.1 | 5.8 | — |
| | 1,517.0 | 107.8 | 124.3 | 2,909.4 | 100 |

At December 31, 2015, our ten largest producing fields held 83% of total proved reserves. We are the principal operator of our production in each of these fields.

| Field | Region | % of Total Proved Reserves | Average Working Interest % | Approximate Average Depth (feet) | Primary Formation |
|---|---|---|---|---|---|
| Watonga-Chickasha (Cana) | Mid-Continent | 56.3 | 45.8 | 13,000' | Woodford |
| Ford, West | Permian Basin | 6.6 | 56.6 | 9,500' | Wolfcamp |
| Lusk | Permian Basin | 5.0 | 55.2 | 9,500' | Bone Spring |
| Dixieland | Permian Basin | 4.6 | 98.6 | 11,000' | Wolfcamp |
| Cottonwood Draw | Permian Basin | 2.8 | 72.6 | 3,000'-10,000' | Delaware/Wolfcamp |
| Phantom | Permian Basin | 1.7 | 59.2 | 11,500' | Bone Spring |
| Two Georges | Permian Basin | 1.7 | 91.4 | 11,500' | Bone Spring |
| Sandbar | Permian Basin | 1.6 | 54.6 | 7,500' | Bone Spring |
| Grisham | Permian Basin | 1.3 | 98.7 | 11,000' | Wolfcamp |
| Benson | Permian Basin | 1.0 | 76.0 | 9,500' | Bone Spring |
| | | 82.6 | | | |

***Acreage***

The following table sets forth the gross and net acres of both developed and undeveloped leases held by Cimarex as of December 31, 2015. Gross acres are the total number of acres in which we own a working interest. Net acres are the gross acres multiplied by our working interest.

| | Acreage | | | | | |
|---|---|---|---|---|---|---|
| | Undeveloped | | Developed | | Total | |
| | Gross | Net | Gross | Net | Gross | Net |
| **Mid-Continent** | | | | | | |
| Kansas | 18,231 | 18,191 | — | — | 18,231 | 18,191 |
| Oklahoma | 121,821 | 85,819 | 699,891 | 292,344 | 821,712 | 378,163 |
| Texas | 22,700 | 12,437 | 133,519 | 57,163 | 156,219 | 69,600 |
| | 162,752 | 116,447 | 833,410 | 349,507 | 996,162 | 465,954 |
| **Permian Basin** | | | | | | |
| New Mexico | 75,025 | 53,388 | 199,752 | 138,776 | 274,777 | 192,164 |
| Texas | 131,658 | 107,886 | 195,368 | 145,363 | 327,026 | 253,249 |
| | 206,683 | 161,274 | 395,120 | 284,139 | 601,803 | 445,413 |
| **Other** | | | | | | |
| Arizona | 2,097,841 | 2,097,841 | 17,207 | — | 2,115,048 | 2,097,841 |
| California | 383,647 | 383,647 | — | — | 383,647 | 383,647 |
| Colorado | 51,354 | 29,389 | 37,696 | 2,120 | 89,050 | 31,509 |
| Gulf of Mexico | 25,000 | 13,000 | 38,388 | 9,724 | 63,388 | 22,724 |
| Louisiana | 3,472 | 400 | 4,020 | 1,048 | 7,492 | 1,448 |
| Michigan | 31,773 | 31,695 | 1,183 | 1,183 | 32,956 | 32,878 |
| Montana | 34,301 | 9,127 | 7,768 | 1,761 | 42,069 | 10,888 |
| Nevada | 1,196,299 | 1,196,299 | 440 | 1 | 1,196,739 | 1,196,300 |
| New Mexico | 1,641,778 | 1,634,170 | 18,572 | 2,618 | 1,660,350 | 1,636,788 |
| Texas | 13,998 | 5,343 | 31,111 | 9,667 | 45,109 | 15,010 |
| Utah | 80,527 | 59,433 | 32,552 | 1,575 | 113,079 | 61,008 |
| Wyoming | 99,133 | 13,777 | 43,147 | 4,201 | 142,280 | 17,978 |
| Other | 191,629 | 168,331 | 10,723 | 5,472 | 202,352 | 173,803 |
| | 5,850,752 | 5,642,452 | 242,807 | 39,370 | 6,093,559 | 5,681,822 |
| **Total** | 6,220,187 | 5,920,173 | 1,471,337 | 673,016 | 7,691,524 | 6,593,189 |

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

| | Acreage | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | | 2017 | | 2018 | | 2019 | | 2020 | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Mid-Continent | 19,679 | 17,978 | 25,219 | 20,582 | 11,207 | 6,474 | 2 | 2 | — | — |
| Permian Basin | 38,445 | 37,960 | 17,739 | 17,724 | 17,393 | 16,684 | 6,482 | 6,482 | — | — |
| Other | 19,281 | 18,936 | 52,494 | 51,479 | 31,603 | 30,823 | 63,333 | 59,098 | 23,744 | 23,688 |
| | 77,405 | 74,874 | 95,452 | 89,785 | 60,203 | 53,981 | 69,817 | 65,582 | 23,744 | 23,688 |
| % of undeveloped | 1.2 | 1.3 | 1.5 | 1.5 | 1.0 | 0.9 | 1.1 | 1.1 | 0.4 | 0.4 |

***Marketing***

Our oil and gas production is sold under short-term arrangements at market-responsive prices. We sell our oil at prices tied directly or indirectly to field postings. Our gas is sold under price mechanisms related to either monthly or daily index prices on pipelines where we deliver our gas.

We sell our oil and gas to a broad portfolio of customers. Our major customers during 2015 were Sunoco Logistics Partners L.P. (Sunoco) and Enterprise Products Partners L.P. (Enterprise). Sunoco and Enterprise accounted for 21% and 17%, respectively, of our consolidated revenues in 2015.

Sunoco is a significant purchaser of our oil in Southeast New Mexico and Canadian County, Oklahoma. Enterprise is a significant oil purchaser in Oklahoma and West Texas. If either of these entities were to stop purchasing our production, we believe there are a number of other purchasers to whom we could sell our production with some delay. If both parties were to discontinue purchasing our product, we believe there would be challenges initially, but ample markets to handle the disruption.

We regularly monitor the credit worthiness of all our customers and may require parent company guarantees, letters of credit or prepayments when deemed necessary.

***Corporate Headquarters and Employees***

Our corporate headquarters is located at 1700 Lincoln St., Suite 3700, Denver, Colorado 80203. On December 31, 2015, and 2014, Cimarex had 925 and 991 employees, respectively. None of our employees are subject to collective bargaining agreements.

***Competition***

The oil and gas industry is highly competitive, particularly for prospective undeveloped leases and purchases of proved reserves. There is also competition for rigs and related equipment used to drill for and produce oil and gas, however, to a lesser extent in the current market environment. Our competitive position is also highly dependent on our ability to recruit and retain geological, geophysical and engineering expertise. We compete for prospects, proved reserves, oil-field services and qualified oil and gas professionals with major and diversified energy companies and other independent operators that have larger financial, human and technological resources than we do.

We compete with integrated, independent and other energy companies for the sale and transportation of our oil and gas to marketing companies and end users. The oil and gas industry competes with other energy industries that supply fuel and power to industrial, commercial and residential consumers. Many of these competitors have greater financial and human resources. The effect of these competitive factors cannot be predicted.

### *Proved Reserves Estimation Procedures*

Proved oil and gas reserve quantities are based on estimates prepared by Cimarex in accordance with the SEC's rules for reporting oil and gas reserves. Our reserve definitions conform with definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. All of our reserve estimates are maintained by our internal Corporate Reservoir Engineering group, which is comprised of reservoir engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of the company. The primary objective of our Corporate Reservoir Engineering group is to maintain accurate forecasts on all properties of the company through ongoing monitoring and timely updates of operating and economic parameters (production forecasts, prices and regional differentials, operating expenses, ownership, etc.) in accordance with guidelines established by the SEC. This separation of function and responsibility is a key internal control.

Cimarex engineers are responsible for estimates of proved reserves. Corporate engineers interact with the exploration and production departments to ensure all available engineering and geologic data is taken into account prior to establishing or revising an estimate. After preparing the reserves update, the corporate engineers review their recommendations with the Vice President of Corporate Engineering. After approval from the Vice President of Corporate Engineering, the revisions are entered into our reserves database by the engineering technician.

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

Together, these internal controls are designed to promote a comprehensive, objective and accurate reserves estimation process. As an additional confirmation of the reasonableness of our internal estimates, DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, reviewed greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2015. The individual primarily responsible for overseeing the review is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over 41 years of experience in oil and gas reservoir studies and evaluations.

The technical employee primarily responsible for overseeing the oil and gas reserves estimation process is Cimarex's Vice President of Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than 21 years of practical experience in oil and gas reservoir evaluation. He has been directly involved in the annual reserves reporting process of Cimarex since 2002 and has served in his current role for the past 11 years.

### *Title to Oil and Gas Properties*

We undertake title examination and perform curative work at the time we lease undeveloped acreage, prepare for the drilling of a prospect or acquire proved properties. We believe title to our properties is good and defensible, and is in accordance with industry standards. Nevertheless, we are involved in title disputes from time to time that result in litigation. Our oil and gas properties are subject to customary royalty interests, liens incidental to operating agreements, tax liens and other burdens and minor encumbrances, easements and restrictions.

### *Government Regulation*

Oil and gas production and transportation is subject to extensive federal, state and local laws and regulations. Compliance with existing laws often is difficult and costly, but has not had a significant adverse effect on our operations or financial condition. In recent years, we have been most directly impacted by federal and state environmental regulations and energy conservation rules. We are also impacted by federal and state regulation of pipelines and other oil and gas transportation systems.

The states in which we conduct operations establish requirements for drilling permits, the method of developing fields, the size of well spacing units, drilling density within productive formations and the unitization or pooling of properties. In addition, state conservation laws include requirements for waste prevention, establish limits on the maximum rate of production from wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production.

*Environmental Regulation.* Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and gas exploration, development and production operations, which consequently impact our operations and costs. These laws and regulations govern, among other things, emissions to the atmosphere, discharges of pollutants into waters, underground injection of waste water, the generation, storage, transportation and disposal of waste materials, and protection of public health, natural resources and wildlife. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas.

Cimarex is committed to environmental protection and believes we are in material compliance with applicable environmental laws and regulations. We obtain permits for our facilities and operations in accordance with the applicable laws and regulations. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations. Expenditures are required to comply with environmental regulations. These costs are a normal, recurring expense of operations and not an extraordinary cost of compliance with current government regulations.

We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our financial position or operations. However, due to continuing changes in these laws and regulations, we are unable to predict with any reasonable degree of certainty any potential delays in development plans that could arise, or our future costs of complying with governmental requirements. We maintain levels of insurance customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of oil, produced water or other substances as well as additional coverage for certain other pollution events.

*Gas Gathering and Transportation.* The Federal Energy Regulatory Commission (FERC) requires interstate gas pipelines to provide open access transportation. FERC also enforces the prohibition of market manipulation by any entity, and the facilitation of the sale or transportation of natural gas in interstate commerce. Interstate pipelines have implemented these requirements, providing us with additional market access and more fairly applied transportation services and rates. FERC continues to review and modify its open access and other regulations applicable to interstate pipelines.

Under the Natural Gas Policy Act (NGPA), natural gas gathering facilities are expressly exempt from FERC jurisdiction. What constitutes "gathering" under the NGPA has evolved through FERC decisions and judicial review of such decisions. We believe that our gathering systems meet the test for non-jurisdictional "gathering" systems under the NGPA and that our facilities are not subject to federal regulations. Although exempt from FERC oversight, our natural gas gathering systems and services may receive regulatory scrutiny by state and federal agencies regarding the safety and operating aspects of the transportation and storage activities of these facilities.

In addition to using our own gathering facilities, we may use third-party gathering services or interstate transmission facilities (owned and operated by interstate pipelines) to ship our gas to markets.

Additional proposals and proceedings that might affect the oil and gas industry are pending before the U.S. Congress, FERC, Bureau of Land Management (BLM), U.S. Environmental Protection Agency (EPA), state legislatures, state agencies, local governments and the courts. We cannot predict when or whether any such proposals may become effective and what effect they will have on our operations. We do not anticipate that compliance with existing federal, state and local laws, rules or regulations will have a material adverse effect upon our capital expenditures, earnings or competitive position.

***Federal and State Income and Other Local Taxation***

Cimarex and the petroleum industry in general are affected by both federal and state income tax laws, as well as other local tax regulations involving ad valorem, personal property, franchise, severance and other excise taxes. We have considered the effects of these provisions on our operations and do not anticipate that there will be any undisclosed impact on our capital expenditures, earnings or competitive position.

## ITEM 1A. RISK FACTORS

The following risks and uncertainties, together with other information set forth in this Form 10-K, should be carefully considered by current and future investors in our securities. These risks and uncertainties are not the only ones we face. Additional risks and uncertainties presently unknown to us or currently deemed immaterial also may impair our business operations. The occurrence of one or more of these risks or uncertainties could materially and adversely affect our business, our financial condition, and the results of our operations, which in turn could negatively impact the value of our securities.

***Oil, gas, and NGL prices fluctuate due to a number of uncontrollable factors, creating a component of uncertainty in our development plans and overall operations. Declines in prices adversely affect our financial results and rate of growth in proved reserves and production.***

Oil and gas markets are volatile. We cannot predict future prices. The prices we receive for our production heavily influence our revenue, profitability, access to capital, and future rate of growth. The prices we receive depend on numerous factors beyond our control. These factors include, but are not limited to, changes in domestic and global supply and demand for oil and gas, the level of domestic and global oil and gas exploration and production activity, geopolitical instability, the actions of the Organization of Petroleum Exporting Countries, weather conditions, technological advances affecting energy consumption, governmental regulations and taxes, and the price and technological advancement of alternative fuels.

Our proved oil and gas reserves and production volumes will decrease unless those reserves are replaced with new discoveries or acquisitions. Accordingly, for the foreseeable future, we expect to make substantial capital investments for the exploration and development of new oil and gas reserves. Historically, we have paid for these types of capital expenditures with cash flow provided by our production operations, our revolving credit facility, and proceeds from the sale of senior notes or equity. Low prices reduce our cash flow and the amount of oil and gas that we can economically produce and may cause us to curtail, delay, or defer certain exploration and development projects. Moreover, low prices also may impact our abilities to borrow under our revolving credit facility and to raise additional debt or equity capital to fund acquisitions.

***If prices stay at recent lower levels or decrease, we will be required to take write-downs of the carrying values of our oil and gas properties and/or our goodwill.***

Accounting rules require that we periodically review the carrying value of our oil and gas properties and goodwill for possible impairment.

As of December 31, 2015, the carrying value of our oil and gas properties subject to a ceiling test exceeded the calculated value of the ceiling limitation and impairment was necessary. If pricing conditions stay at current levels or decline further we will incur full cost ceiling impairments in future quarters. Because the ceiling calculation uses rolling 12-month average commodity prices, the effect of lower quarter-over-quarter prices in 2016 compared to 2015 is a lower ceiling value each quarter. This will result in ongoing impairments each quarter until prices stabilize or improve. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet.

***U.S. or global financial markets may impact our business and financial condition.***

A credit crisis or other turmoil in the U.S. or global financial system may have a negative impact on our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. This could have an impact on our flexibility to react to changing economic and business conditions. Deteriorating economic conditions could have a negative impact on our lenders, the purchasers of our oil and gas production and the working interest owners in properties we operate, causing them to fail to meet their obligations to us.

***Failure to economically replace oil and gas reserves could negatively affect our financial results and future rate of growth.***

In order to replace the reserves depleted by production and to maintain or increase our total proved reserves and overall production levels, we must either locate and develop new oil and gas reserves or acquire producing properties from others. This requires significant capital expenditures and can impose reinvestment risk for us, as we may not be able to continue to replace our reserves economically. While we occasionally may seek to acquire proved reserves, our main business strategy is to grow through exploration and drilling. Without successful exploration and development, our reserves, production and revenues could decline rapidly, which would negatively impact the results of our operations.

Exploration and development involves numerous risks, including new governmental regulations and the risk that we will not discover any commercially productive oil or gas reservoirs. Additionally, it can be unprofitable, not only from drilling dry holes, but also from drilling productive wells that do not return a profit because of insufficient reserves or declines in commodity prices.

Our drilling operations may be curtailed, delayed, or canceled for many reasons. Factors such as unforeseen poor drilling conditions, title problems, unexpected pressure irregularities, equipment failures, accidents, adverse weather conditions, compliance with environmental and other governmental requirements, bans, moratoria or other restrictions implemented by local governments and the cost of, or shortages or delays in the availability of, drilling and completion services could negatively impact our drilling operations.

***Our proved reserve estimates may be inaccurate and future net cash flows are uncertain.***

Estimates of total proved oil and gas reserves (consisting of proved developed and proved undeveloped reserves) and associated future net cash flow depend on a number of variables and assumptions. See "Forward-Looking Statement" in this report. Among others, changes in any of the following factors may cause actual results to vary considerably from our estimates:

- timing of development expenditures;
- amount of required capital expenditures and associated economics;
- recovery efficiencies, decline rates, drainage areas, and reservoir limits;
- anticipated reservoir and production characteristics and interpretations of geologic and geophysical data;
- production rates, reservoir pressure, unexpected water encroachment, and other subsurface conditions;
- oil, gas, and NGL prices;
- governmental regulation;
- access to assets restricted by local government action;
- operating costs;
- property, severance, excise and other taxes incidental to oil and gas operations;
- workover and remediation costs; and
- federal and state income taxes.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with guidelines established by the SEC. DeGolyer and MacNaughton, independent petroleum engineers, reviewed our reserve estimates for properties that comprised at least 80% of the discounted future net cash flows before income taxes, using a 10% discount rate, as of December 31, 2015.

The cash flow amounts referred to in this filing should not be construed as the current market value of our proved reserves. In accordance with SEC guidelines, the estimated discounted net cash flow from proved reserves is based on the average of the previous 12 months' first-day-of-the-month prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially different.

***Hedging transactions may limit our potential gains and involve other risks.***

To limit our exposure to price risk, we enter into hedging agreements from time to time, and use commodity derivatives. Hedges limit volatility and increase the predictability of a portion of our cash flow. These transactions also limit our potential gains when oil and gas prices exceed the prices established by the hedges.

In certain circumstances, hedging transactions may expose us to the risk of financial loss, including instances in which:

- the counterparties to our hedging agreements fail to perform;
- there is a sudden unexpected event that materially increases oil and natural gas prices; or
- there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement.

Because we account for derivative contracts under mark-to-market accounting, during periods we have hedging transactions in place we expect continued volatility in derivative gains or losses on our income statement as changes occur in the relevant price indexes.

***The adoption of derivatives legislation could have an adverse effect on our ability to use derivative instruments as hedges against fluctuating commodity prices.***

In July 2010, the Dodd-Frank Act was enacted, representing an extensive overhaul of the framework for regulation of U.S. financial markets. The Dodd-Frank Act called for various regulatory agencies, including the SEC and the Commodities Futures Trading Commission (CFTC), to establish regulations for implementation of many of its provisions. The Dodd-Frank Act contains significant derivatives regulations, including requirements that certain transactions be cleared on exchanges and that cash collateral (margin) be posted for such transactions. The Dodd-Frank Act provides for an exemption from the clearing and cash collateral requirements for commercial end-users, such as Cimarex, and it includes a number of defined terms used in determining how this exemption applies to particular derivative transactions and the parties to those transactions.

We have satisfied the requirements for the commercial end-user exception to the clearing requirement and intend to continue to engage in derivative transactions. In December 2015, the CFTC approved final rules on margin requirements that will have an impact on our hedging counterparties and an interim final rule exemption from the margin requirements for certain uncleared swaps with commercial end-users. The final rules did not impose additional requirements on commercial end-users. The ultimate effect of these new rules and any additional regulations is currently uncertain. New rules and regulations in this area may result in significant increased costs and disclosure obligations as well as decreased liquidity as entities that previously served as hedge counterparties exit the market.

***We have been an early entrant into new or emerging resource plays. As a result, our drilling results in these areas are uncertain. The value of our undeveloped acreage may decline and we may incur impairment charges if drilling results are unsuccessful.***

New or emerging oil and gas resource plays have limited or no production history. Consequently, in those areas it is difficult to predict our future drilling costs and results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected. Similarly, our production may be lower than initially expected, and the value of our undeveloped acreage may decline if our results are unsuccessful. As a result, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays.

Furthermore, unless production is established during the primary term of certain of our undeveloped oil and gas leases, the leases will expire, and we will lose our right to develop those properties.

***Our business depends on oil and gas pipeline and transportation facilities, some of which are owned by others.***

In addition to the existence of adequate markets, our oil and natural gas production depends in large part on the proximity and capacity of pipeline systems, as well as storage, transportation, processing and fractionation facilities, most of which are owned by third parties. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. This is more likely in remote areas without established infrastructure, such as our Culberson County, Texas area where we have significant development activities. The lack of availability or capacity in these facilities or the loss of these facilities due to weather, fire or other reasons, for an extended period of time could negatively affect our revenues.

A limited number of companies purchase a majority of our oil, NGLs and natural gas. The loss of a significant purchaser could have a material adverse effect on our ability to sell production.

Federal and state regulation of oil and natural gas, local government activity, adverse court rulings, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce and market oil and natural gas.

***Competition in our industry is intense and many of our competitors have greater financial and technological resources.***

We operate in the competitive area of oil and gas exploration and production. Many of our competitors are large, well-established companies that have larger operating staffs and greater capital resources. These competitors may be willing to pay more for exploratory prospects and productive oil and gas properties. They may also be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit.

Because our activity is also concentrated in areas of heavy industry competition, there is heightened demand for personnel, equipment, power, services, facilities and resources, resulting in higher costs than in other areas. Such intense competition also could result in delays in securing, or the inability to secure, the personnel, equipment, power, services, resources or facilities necessary for our development activities, which could negatively impact our production volumes. We also face higher costs in remote areas where vendors can charge higher rates due to that remoteness along with the inability to attract employees to those areas and the ability to deploy their resources in easier to access areas.

***We are subject to complex laws and regulations that can adversely affect the cost, manner, and feasibility of doing business.***

Exploration, production and the sale of oil and gas are subject to extensive laws and regulations, including those implemented to protect the environment, human health and safety and wildlife. Federal, state, and local regulatory agencies frequently require permitting and impose conditions on our activities. During the permitting process, these regulatory agencies often exercise considerable discretion in both the timing and scope of the permits, and the public, including special interest groups, often has an opportunity to influence the timing and outcome of the process. The requirements or conditions imposed by these agencies can be costly and can delay the commencement of our operations. In addition, a number of initiatives have been put forth by the President Obama administration not in the form of regulation but rather as Presidential or Secretarial Memoranda which have the potential to impact the cost of doing business or could result in substantial delays in permitting, drilling and other oil and gas activities. One example is the Presidential Memorandum on "no net loss" which will take the form of agency action by the Department of Interior, EPA and other agencies to ensure that harmful effects to lands are avoided, minimized and those which remain mitigated up to and including prohibiting actions which may have been previously allowed or requiring compensation.

Failing to comply with any of the applicable laws and regulations, or Presidential initiatives, could result in the suspension or termination of our operations and subject us to administrative, civil and criminal liabilities and penalties. Such costs could have a material adverse effect on both our financial condition and operations.

***Environmental matters and costs can be significant.***

As an owner, lessee, or operator of oil and gas properties, we are subject to various complex, stringent and constantly evolving environmental laws and regulations. Our operations inherently create the risk of environmental liability to the government and private parties stemming from our use, generation, handling and disposal of water and waste materials, as well as the release of hydrocarbons or other substances into the air, soil, or water. The environmental laws and regulations to which we are subject impose numerous obligations applicable to our operations, including: the acquisition of permits before conducting regulated activities associated with drilling for and producing oil and gas; the restriction of types, quantities, and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, waters of the United States, and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue.

Liabilities under certain environmental laws can be joint and several and may in some cases be imposed regardless of fault on our part such as where we own a working interest in a property operated by another party. We also could be held liable for damages or remediating lands or facilities previously owned or operated by others regardless of whether such contamination resulted from our own actions and regardless if we were in compliance with all applicable law at the time. Further, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Since these environmental risks generally are not fully insurable and can result in substantial costs, such liabilities could have a material adverse effect on both our financial condition and operations.

***Our financial condition and results of operations may be materially adversely affected if we incur costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.***

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, pollutants, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, discharge, transportation and disposal of pollutants and solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The most significant of these environmental laws are as follows:

- The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as CERCLA or the Superfund law, and comparable state laws, which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;

- The Oil Pollution Act of 1990 (OPA), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States;

- The Resource Conservation and Recovery Act (RCRA), as amended, and comparable state statutes, which governs the treatment, storage and disposal of solid waste;

- The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act (CWA), which governs the discharge of pollutants, including natural gas wastes into federal and state waters;

- The Safe Drinking Water Act (SDWA), which governs the disposal of wastewater in underground injection wells; and

- The Clean Air Act (CAA) which governs the emission of pollutants into the air.

We believe we are in substantial compliance with the requirements of CERCLA, RCRA, OPA, CWA, SDWA, CAA and related state and local laws and regulations. We also believe we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although the current costs of managing our wastes as they presently are classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes and have a material adverse effect on our financial condition and operations.

***Federal regulatory initiatives relating to the protection of threatened or endangered species could result in increased costs and additional operating restrictions or delays.***

The Federal Endangered Species Act (ESA) was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. The U.S. Fish and Wildlife Service (FWS) may designate critical habitat and suitable habitat areas it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal oil and natural gas leases in areas where certain species are currently listed as threatened or endangered, or could be listed as such, under the ESA. Operations in areas where threatened or endangered species or their habitat are known to exist may require us to incur increased costs to implement mitigation or protective measures and also may restrict or preclude our drilling activities in those areas or during certain seasons, such as breeding and nesting seasons. On March 27, 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas, New Mexico and Oklahoma, where we conduct operations, as a threatened species under the ESA. Listing of the lesser prairie chicken as a threatened species imposes restrictions on disturbances to critical habitat by landowners and drilling companies that would harass, harm or otherwise result in a "taking" of this species. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies (WAFWA), pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. We entered into a voluntary Candidate Conservation Agreement (CCA) with the WAFWA, whereby we agreed to take certain actions and limit certain activities, such as limiting drilling on certain portions of our acreage during nesting seasons, in an effort to protect the lesser prairie chicken. Such CCA could result in increased costs to us from species protection measures, time delays or limitations on drilling activities, which costs, delays or limitations may be significant. While a federal judge in Texas vacated the listing of the lesser prairie chicken in 2015, listing petitions continue to be filed with the FWS which could impact our operations. Many non-governmental organizations (NGOs) work closely with the FWS regarding the listing of many species, including species with broad and even nationwide ranges. The recent listing of the Mexican Long Nosed bat, whose habitat includes the Permian Basin where we operate, is an example of the NGOs' influence on ESA listing decisions. The increase in endangered species listings may impact our ability to explore for or produce oil and gas in certain areas and increase our costs.

***Our hydraulic fracturing activities are subject to risks that could negatively impact our operations and profitability.***

We use hydraulic fracturing for the completion of almost all of our wells. Hydraulic fracturing is a process that involves pumping fluid and proppant at high pressure into a hydrocarbon bearing formation to create and hold open fractures. Those fractures enable gas or oil to move through the formation's pores to the well bore. Typically, the fluid used in this process is primarily water. In plays where hydraulic fracturing is necessary for successful development, the demand for water may exceed the supply. A lack of readily available water or a significant increase in the cost of water could cause delays or increased completion costs.

While hydraulic fracturing historically has been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation from federal agencies. For example, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the SDWA involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Although the EPA has delegated the permitting authority for the SDWA's Underground Injection Control Class II programs in Oklahoma, Texas or New Mexico where we maintain operational acreage, the EPA is encouraging state programs to review and consider use of such draft guidance. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. On April 7, 2015, the EPA published in the Federal Register a proposed rule requiring federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback water" as well as "produced water." If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. The public comment period for the proposed rates ended on June 8, 2015 and final rules have not yet been issued. Moreover, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014.

In addition, on March 26, 2015, the federal Bureau of Land Management published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, development of appropriate plans for managing flowback water that returns to the surface, increased standards for interim storage of recovered waste fluids, and submission to the Bureau of Land Management of detailed information on the geology, depth and location of preexisting wells. This rule originally was scheduled to take effect on June 24, 2015. However, the rule is the subject of several pending lawsuits filed by industry groups, two Indian tribes, and at least four states, alleging that federal law does not give the Bureau of Land Management authority to regulate hydraulic fracturing. The federal judge has enjoined the rule until the merits of the case can be heard sometime in 2016.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA's draft report was released on June 4, 2015. The findings of the report suggest that hydraulic fracturing does not pose a systemic risk to groundwater although there are risks to both groundwater and soils posed by inadequate water handling practices in certain situations. A public comment period on the report was open until August 28, 2015 and a series of public hearings were conducted by the EPA's Scientific Advisory Board (SAB) throughout the fall of 2015. The EPA issued its final report and concluded there is no evidence of widespread contamination associated with hydraulic fracturing. The SAB has indicated that they want to continue to study the matter. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing.

Additionally, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Most producing states, including Texas and Colorado, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether.

Any of the above factors could have a material adverse effect on our financial position, results of operations or cash flows and could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

***Air quality regulations could negatively impact our operations and profitability.***

In August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in volatile organic compounds (VOCs) emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry. Proposed rules implementing the various elements of the package were published in September 2015 and the public comment period ended in December 2015. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

***The adoption of climate change legislation or regulations restricting emission of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.***

Studies have suggested that emission of certain gases, commonly referred to as greenhouse gases (GHGs) may be impacting the earth's climate. Methane, a primary component of natural gas, and carbon dioxide, also present in natural gas as a secondary product, sometimes considered an impurity or a by-product of the burning of oil and natural gas, are examples of GHGs. The U.S. Congress and various states have been evaluating, and in some cases implementing, climate-related legislation and other regulatory initiatives that restrict emissions of GHGs. In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the Federal Clean Air Act that establish Prevention of Significant Deterioration (PSD) and Title V permit reviews for GHG emissions from certain large stationary sources. Facilities required to obtain PSD and/or Title V permits under EPA’s GHG Tailoring Rule for their GHG emissions also may be required to meet "Best Available Control Technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities on an annual basis, which includes certain of our operations. In recent proposed rulemaking EPA is widening the scope of annual GHG reporting to include not only activities associated with completion and workover of gas wells with hydraulic fracturing and activities associated with oil and natural gas production operations, but also completions and workovers of oil wells with hydraulic fracturing, gathering and boosting systems and transmission pipelines.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of

GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. In January 2015, President Obama announced a series of administration actions to reduce methane emissions, including rulemaking by the EPA and the BLM as well as updating of standards by the Department of Transportation's Pipeline and Hazardous Materials Administration. The current administration intends to promulgate proposed climate change rulemaking this summer aimed at reducing GHG emissions by 45% by 2025 compared to 2012 levels. On January 22, 2016, the Department of the Interior announced its proposed emissions mandate on oil and natural gas producers who operate on federal and Indian lands. While we expect new legislation and regulations to increase the cost of business, at this time it is not possible to quantify the impact on our business. Any such future laws and final regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to develop and implement best management practices aimed at reducing GHG emissions, install and maintain emissions control technologies, as well as monitor and report on GHG emissions associated with our operations, which would increase our operating costs, and such requirements also could adversely affect demand for the oil and natural gas that we produce.

***Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of saltwater produced in connection with our oil and gas production, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business.***

We dispose of large volumes of saltwater produced in connection with our drilling and production operations, pursuant to permits issued to us or third party operators of disposal wells by governmental authorities overseeing produced water disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities.

There exists a growing concern that the injection of produced water into belowground disposal wells triggers seismic activity in certain areas, including Oklahoma and Texas, where we operate. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in the permitting of saltwater disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in 2014, the Oklahoma Corporation Commission adopted rules for operators of saltwater disposal wells in certain seismically-active areas, or Areas of Interest, in the Arbuckle formation, requiring operators to monitor and record well pressure and discharge volume on a daily basis and further requiring operators of wells permitted for disposal of 20,000 barrels per day or more of saltwater to conduct mechanical integrity testing. Throughout 2015, the Oklahoma Corporation Commission's Oil and Gas Conservation Division, or OGCD, issued a series of directives, expanding the areas of interest for induced seismicity and enhanced disposal restrictions and limiting the depths at which produced water could be injected or, in the alternative, reducing disposal volumes. Additional regulations and restrictions have been proposed in Oklahoma in 2016.

In addition, in 2014 the Texas Railroad Commission, or TRC, published a new rule governing permitting or re-permitting of disposal wells in Texas that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If a permittee or a prospective permittee fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

The adoption and implementation of any new laws, regulations, or directives that restrict our ability to dispose of produced water, by changing the depths of disposal wells, reducing the volume of oil and natural gas wastewater disposed in such wells, restricting disposal well locations or otherwise, or by requiring us or third parties who dispose of our saltwater to shut down disposal wells, could increase disposal costs or require us to shut in a substantial number of our oil and natural gas wells or otherwise have a material adverse effect on our ability to produce oil and gas economically and, accordingly, could materially and adversely affect our business, financial condition and results of operations.

***We use some of the latest available horizontal drilling and completion techniques, which involve risk and uncertainty in their application.***

Our horizontal drilling operations utilize some of the latest drilling and completion techniques. The risks or such techniques include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore;
- being able to run tools and other equipment consistently through the horizontal wellbore;
- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Any of the above factors could have a material adverse effect on our financial position, results of operations or cash flows.

***We may be subject to information technology system failures, network disruptions and breaches in data security and our business, financial position, results of operations and cash flows could be negatively affected by such security threats and disruptions.***

As an oil and gas producer, we face various security threats, including cybersecurity threats such as attempts to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing facilities, pipelines and refineries; and threats from terrorist acts. Cybersecurity attacks are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data, which could have an adverse effect on our reputation, business, financial condition, results of operations or cash flows. While we have not suffered any material losses relating to such attacks, there can be no assurance that we will not suffer such losses in the future.

We rely heavily on our information systems, and the availability and integrity of these systems are essential for us to conduct our business and operations. In addition to cybersecurity and data security threats, other information system failures and network disruptions could have a material adverse effect on our ability to conduct our business. We could experience system failures due to power or telecommunications failures, human error, natural disasters, fire, sabotage, hardware or software malfunction or defects, computer viruses, intentional acts of vandalism or terrorism and similar acts or occurrences. Such system failures could result in the unanticipated disruption of our operations, communications or processing of transactions, as well as loss of, or damage to, sensitive information, facilities, infrastructure and systems essential to our business and operations, the failure to meet regulatory standards and the reporting of our financial results, and other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position, results of operations and cash flows.

While management has taken steps to address these concerns by implementing network security and internal control measures to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure, our implementation of such procedures and controls may result in increased costs, and there can be no assurance that a system failure or data security breach will not occur and have a material adverse effect on our business, financial condition and results of operations. In addition, as cybersecurity threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cybersecurity or information technology infrastructure vulnerabilities.

***Our limited ability to influence operations and associated costs on non-operated properties could result in economic losses that are partially beyond our control.***

Other companies operate approximately 26% of our net production. Our success in properties operated by others depends upon a number of factors outside of our control. These factors include timing and amount of capital expenditures, the operator's expertise and financial resources, approval of other participants in drilling wells, selection of technology and maintenance of safety and environmental standards. Our dependence on the operator and other working interest owners for these projects could prevent the realization of our targeted returns on capital in drilling or acquisition activities.

***Our business involves many operating risks that may result in substantial losses for which insurance may be unavailable or inadequate.***

Our operations are subject to hazards and risks inherent in drilling for oil and gas, such as fires, natural disasters, explosions, formations with abnormal pressures, casing collapses, uncontrollable flows of underground gas, blowouts, surface cratering, pipeline ruptures or cement failures. Other such risks include theft, vandalism, environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases. Any of these risks can cause substantial losses resulting from:

- injury or loss of life;
- damage to, loss of or destruction of, property, natural resources and equipment;
- pollution and other environmental damages;
- regulatory investigations, civil litigation and penalties;
- damage to our reputation;
- suspension of our operations; and
- costs related to repair and remediation.

In addition, our liability for environmental hazards may include conditions created by the previous owners of properties that we purchase or lease.

We maintain insurance coverage against some, but not all, potential losses. We do not believe that insurance coverage for all environmental damages that could occur is available at a reasonable cost. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operation.

***We may not be able to generate enough cash flow to meet our debt obligations.***

At December 31, 2015, our long-term debt consisted of $750 million of 4.375% senior notes due in 2024 and $750 million of 5.875% senior notes due in 2022. In addition to interest expense and principal on our long-term debt, we have demands on our cash resources including, among others, operating expenses and capital expenditures.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon future performance and our ability to repay or refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital market conditions, results of operations and other factors, many of which are beyond our control. Our ability to meet our debt service obligations also may be impacted by changes in prevailing interest rates, as borrowing under our existing revolving credit facility bears interest at floating rates.

We may not generate sufficient cash flow from operations. Without sufficient cash flow, there may not be adequate future sources of capital to enable us to service our indebtedness or to fund our other liquidity needs. If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling assets; or
- restructuring or refinancing debt.

We may be unable to complete any such strategies on satisfactory terms, if at all. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations.

***The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.***

The indenture governing our senior notes and our credit agreement contain various restrictive covenants that may limit management's discretion in certain respects. In particular, these agreements limit Cimarex's and its subsidiaries' ability to, among other things:

- create certain liens;
- consolidate, merge or transfer all, or substantially all, of our assets and our restricted subsidiaries;
- enter into sale and leaseback transactions.

In addition, our revolving credit agreement requires us to maintain a total debt to capitalization ratio (as defined in the credit agreement) of not more than 65%. Also, the indenture, under which we issued our senior unsecured notes, restricts us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indenture) is at least 2.25. The additional indebtedness limitation does not prohibit us from borrowing under our revolving credit facility. See Note 3 to the Consolidated Financial Statements for further information.

If we fail to comply with the restrictions in the indenture governing our senior notes or the agreement governing our credit facility or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

***Our acquisition activities may not be successful, which may hinder our replacement of reserves and adversely affect our results of operations.***

The successful acquisition of properties requires an assessment of several factors, including:

- geological risks and recoverable reserves;
- future oil and gas prices and their appropriate market differentials;
- operating costs; and
- potential environmental risks and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections will not likely be performed on every well or facility, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Furthermore, the seller may be unwilling or unable to provide effective contractual protection against all or part of the identified problems.

***We may lose leases if production is not established within the time periods specified in the leases.***

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. If we are not able to renew leases before they expire, any proved undeveloped reserves associated with such leases will be removed from our proved reserves. The combined net acreage expiring in the next three years represents 3.7% of our total net undeveloped acreage at December 31, 2015. At that date, we had leases representing 74,874 net acres expiring in 2016, 89,785 net acres expiring in 2017, and 53,981 net acres expiring in 2018. Our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

***Our disposition activities may be subject to factors beyond our control, and in certain cases we may retain unforeseen liabilities for certain matters***.

We regularly sell non-core assets in order to increase capital resources available for other core assets and to create organizational and operational efficiencies. We also occasionally sell interests in core assets for the purpose of accelerating the development and increasing efficiencies in such core assets. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the assets with terms we deem acceptable.

Sellers often retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or of the indemnification obligation is difficult to quantify at the time of the transaction and ultimately could be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, the company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

***Competition for experienced, technical personnel may negatively impact our operations.***

Our exploratory and development drilling success depends, in part, on our ability to attract and retain experienced professional personnel. The loss of any key executives or other key personnel could have a material adverse effect on our operations. As we continue to develop our asset base and the scope of our operations, our future profitability will depend on our ability to attract and retain qualified personnel, particularly individuals with a strong background in geology, geophysics, engineering and operations.

***We are involved in various legal proceedings, the outcome of which could have an adverse effect on our liquidity.***

In the normal course of business, we have various lawsuits and related disputed claims, including but not limited to claims concerning title, royalty payments, environmental issues, personal injuries, and contractual issues. Although we currently believe the resolution of these lawsuits and claims, individually or in the aggregate, would not have a material adverse effect on our financial condition or results of operations, our assessment of our current litigation and other legal proceedings could change in light of the discovery of facts with respect to legal actions or other proceedings pending against us not presently known to us or determinations by judges, juries or other finders of fact that are not in accord with our evaluation of the possible liability or outcome of such proceedings. Therefore, there can be no assurance that outcomes of future legal proceedings would not have an adverse effect on our liquidity and capital resources.

***Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, as a result of future legislation.***

Various proposals have been made recommending the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. Legislation is often introduced in Congress which would implement many of these proposals. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could have an adverse effect on our financial position.

**ITEM 1B. UNRESOLVED STAFF COMMENTS**

None.

**ITEM 3. LEGAL PROCEEDINGS**

The information set forth under the heading “Litigation” in Note 10 of the Notes to the Consolidated Financial Statements included in Part II, Item 8 of this Annual Report on Form 10-K is incorporated by reference in response to this item.

**ITEM 4. MINE SAFETY DISCLOSURES**

Not applicable.

## PART II

### ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our $0.01 par value common stock trades on the New York Stock Exchange (NYSE) under the symbol XEC. A cash dividend was paid to stockholders in each quarter of 2015. Future dividend payments will depend on the company's level of earnings, financial requirements and other factors considered relevant by the Board of Directors.

*Stock Prices and Dividends by Quarter.* The following table sets forth, for the periods indicated, the high and low sales price per share of Common Stock on the NYSE and the quarterly dividends paid per share.

| **2015** | **High** | **Low** | **Dividends Paid Per Share** |
|---|---|---|---|
| First Quarter | $ 118.87 | $ 91.74 | $ 0.16 |
| Second Quarter | $ 132.18 | $ 108.59 | $ 0.16 |
| Third Quarter | $ 118.87 | $ 97.23 | $ 0.16 |
| Fourth Quarter | $ 124.91 | $ 85.00 | $ 0.16 |

| **2014** | **High** | **Low** | **Dividends Paid Per Share** |
|---|---|---|---|
| First Quarter | $ 121.71 | $ 92.38 | $ 0.14 |
| Second Quarter | $ 143.75 | $ 111.49 | $ 0.16 |
| Third Quarter | $ 150.71 | $ 125.25 | $ 0.16 |
| Fourth Quarter | $ 129.12 | $ 96.02 | $ 0.16 |

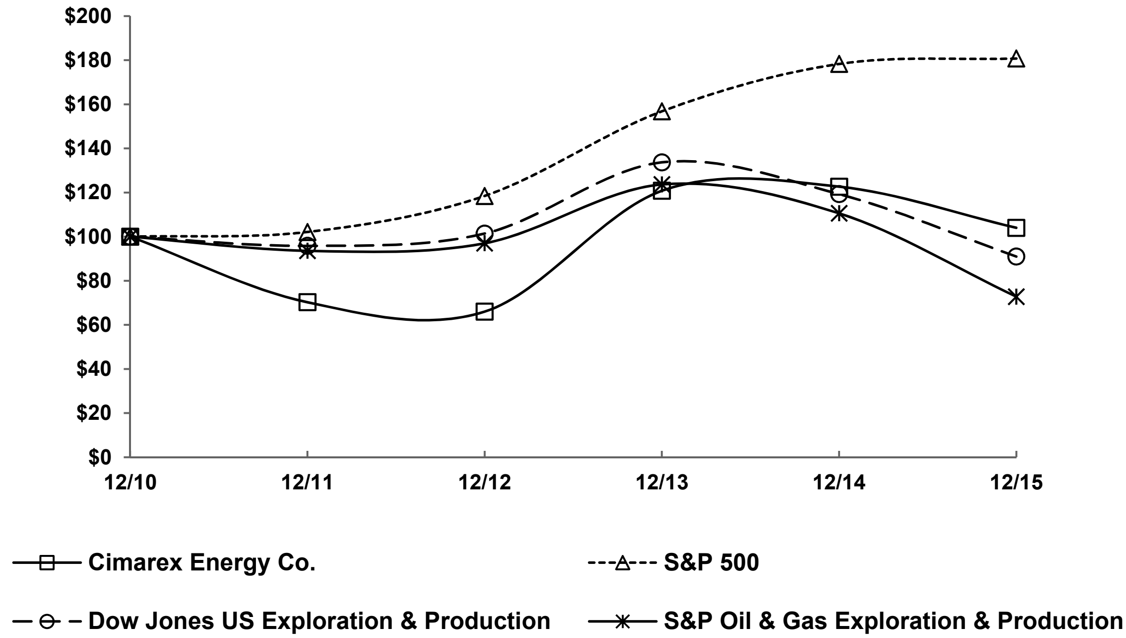
The closing price of Cimarex stock as reported on the New York Stock Exchange on February 12, 2016, was $84.67. At December 31, 2015, Cimarex's 94,820,570 shares of outstanding common stock were held by approximately 1,960 stockholders of record.

The following table sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the company at December 31, 2015:

| **Plan Category** | **(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights** | **(b) Weighted-average exercise price of outstanding options, warrants, and rights** | **(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))** |
|---|---|---|---|
| Equity compensation plans approved by security holders | 299,229 | $ 93.76 | 4,423,042 |
| Equity compensation plans not approved by security holders | — | — | — |
| Total | 299,229 | $ 93.76 | 4,423,042 |

The following graph compares the cumulative 5-year total return attained by stockholders on Cimarex Energy Co.'s common stock relative to the cumulative total returns of the S&P 500 index, the Dow Jones US Exploration & Production index, and the S&P Oil & Gas Exploration & Production index. The graph tracks the performance of a $100 investment in our common stock and in each of the indexes (with the reinvestment of all dividends) from December 31, 2010 to December 31, 2015. The stock price performance included in this graph is not necessarily indicative of future stock price performance.

## COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*




*$100 invested on 12/31/10 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.



| | 12/2010 | 12/2011 | 12/2012 | 12/2013 | 12/2014 | 12/2015 |
|---|---|---|---|---|---|---|
| Cimarex Energy Co. | $ 100.00 | $ 70.26 | $ 66.01 | $ 120.78 | $ 122.66 | $ 104.00 |
| S&P 500 | $ 100.00 | $ 102.11 | $ 118.45 | $ 156.82 | $ 178.29 | $ 180.75 |
| Dow Jones US Exploration & Production | $ 100.00 | $ 95.81 | $ 101.39 | $ 133.68 | $ 119.27 | $ 90.97 |
| S&P Oil & Gas Exploration & Production | $ 100.00 | $ 93.57 | $ 96.98 | $ 123.65 | $ 110.55 | $ 72.80 |

*Stock Repurchases.* In December 2005, the Board of Directors authorized the repurchase of up to four million shares of our common stock. The authorization expired on December 31, 2011. Through December 31, 2007, we had repurchased and cancelled a total of 1,364,300 shares at an overall average price of $39.05. No shares have been repurchased since the quarter ended September 30, 2007.

## ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth below should be read in conjunction with the Consolidated Financial Statements and accompanying notes thereto provided in Item 8 of this report.

| | For the Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2012 | 2011 |
| | (in millions, except per share amounts) | | | | |
| Operating Results: | | | | | |
| Oil, gas and NGL sales | $ 1,418 | $ 2,373 | $ 1,953 | $ 1,582 | $ 1,704 |
| Total Revenues | $ 1,453 | $ 2,424 | $ 1,998 | $ 1,624 | $ 1,758 |
| Net income (loss) (1) | $ (2,409) | $ 507 | $ 565 | $ 354 | $ 530 |
| Earnings (loss) per share to common Stockholders: | | | | | |
| Basic | $ (25.92) | $ 5.79 | $ 6.48 | $ 4.08 | $ 6.17 |
| Diluted | $ (25.92) | $ 5.78 | $ 6.47 | $ 4.07 | $ 6.15 |
| Cash dividends declared per share | $ 0.64 | $ 0.64 | $ 0.56 | $ 0.48 | $ 0.40 |
| Cash flow data: | | | | | |
| Net cash flow provided by operating activities | $ 692 | $ 1,619 | $ 1,324 | $ 1,193 | $ 1,292 |
| Net cash used in investing activities | $ (1,009) | $ (1,740) | $ (1,531) | $ (1,415) | $ (1,429) |
| Net cash provided by financing activities | $ 691 | $ 522 | $ 142 | $ 289 | $ 25 |

| | December 31, | | | | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2012 | 2011 |
| | (in millions, except proved reserves amounts) | | | | |
| Balance sheet data: | | | | | |
| Cash and Cash Equivalents | $ 779 | $ 406 | $ 5 | $ 70 | $ 2 |
| Oil and Gas Properties, net (1) | $ 3,276 | $ 6,904 | $ 5,966 | $ 5,005 | $ 4,126 |
| Goodwill | $ 620 | $ 620 | $ 620 | $ 620 | $ 620 |
| Total assets (1) (2) | $ 5,243 | $ 8,708 | $ 7,243 | $ 6,294 | $ 5,355 |
| Long-term Obligations | | | | | |
| Long-term debt (principal) | $ 1,500 | $ 1,500 | $ 924 | $ 750 | $ 405 |
| Deferred Income Taxes | $ 353 | $ 1,755 | $ 1,460 | $ 1,121 | $ 904 |
| Other | $ 197 | $ 194 | $ 164 | $ 313 | $ 302 |
| Stockholders' equity | $ 2,798 | $ 4,501 | $ 4,022 | $ 3,475 | $ 3,131 |
| Proved Reserves: | | | | | |
| Oil (MBbls) | 107,798 | 118,992 | 108,533 | 77,921 | 72,322 |
| Gas (Bcf) | 1,517 | 1,667 | 1,294 | 1,252 | 1,216 |
| NGL (MBbls) | 124,277 | 125,273 | 92,044 | 89,909 | 65,815 |
| Total equivalent (Bcfe) | 2,909 | 3,132 | 2,497 | 2,259 | 2,045 |

(1) During 2015, we recorded non-cash full cost ceiling impairments to our oil and gas properties totaling $3.7 billion ($2.4 billion, net of tax).

(2) At December 31, 2015, we adopted new guidance which requires debt issuance costs (except for those related to revolving credit facilities) to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability rather than as an asset. Such costs were previously recorded as deferred assets. Prior periods have been adjusted to conform to this guidance. See Notes 1 and 3 to the Consolidated Financial Statements of this report for additional information.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our Consolidated Financial Statements included in Item 8 of this report and also with *"Risk Factors"* in Item 1A of this report. This discussion also includes forward-looking statements. Please refer to "*Cautionary Information about Forward-Looking Statements*" in Part I of this report for important information about these types of statements.

### *OVERVIEW*

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 diversified drilling portfolio. 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 profitable increases in proved reserves and production. Our robust drilling portfolio 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 oil supplies began to outpace demand. During 2015 and thus far in 2016, global oil supply has continued to outpace demand resulting in further deterioration in realized prices for oil production.

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

Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production. Compared to 2014, our realized oil price for 2015 fell 48% to $43.38 per barrel. Similarly, our realized price for natural gas dropped 43% to $2.53 per Mcf and our realized price for NGLs declined 59% to $13.75 per barrel. The U.S. oil and gas industry continues to confront weak commodity prices due to oversupply, growing inventories and concern over global demand.

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

Based on current economic conditions, our 2016 exploration and development expenditures are projected to range from $600-$650 million. Investments in gathering and processing infrastructure and other fixed assets are expected to approximate an additional $50 million.

*2015 Summary of Operating and Financial Results*

Continued weakness in commodity prices had a significant adverse impact on our results of operations, our balance sheet and the amount of cash flow available to invest in exploration and development activities.

The following is a summary of certain 2015 operating and financial results:

- Average daily production increased 13% to 984.5 MMcfe per day.
- Oil production grew 19% to 51,132 barrels per day, gas volumes increased by 9% to 463.0 MMcf per day and NGL volumes rose 15% to 35,789 barrels per day.
- We added 571 Bcfe of proved reserves from extensions and discoveries and net positive performance revisions, replacing 159% of production.
- In the second quarter of 2015 we completed a common stock offering and received net proceeds of $730.0 million.
- Cash on hand at year end was $779.4 million.
- Production revenues declined 40% to $1.4 billion.
- Cash flow provided by operating activities of $691.5 million was 57% lower than that of the prior year.
- We incurred non-cash impairments of our oil and gas properties totaling $3.7 billion.
- We had a net loss for the year of $2.4 billion, or $25.92 per diluted share.
- Proved reserves decreased 7.1% to 2,909.4 Bcfe primarily due to negative price-related revisions of 398.8 Bcfe.

In response to lower commodity prices we significantly reduced our 2015 exploration and development expenditures to $877.0 million compared to $1.9 billion in 2014.

Total debt at December 31, 2015 consisted of $1.5 billion of senior notes, with $750 million maturing in 2022 and $750 million maturing in 2024, unchanged from total debt at December 31, 2014.

***Proved Reserves***

| | Year Ended December 31, 2015 | | | |
|---|---|---|---|---|
| | Gas (MMcf) | Oil (MBbl) | NGL (MBbl) | Total Gas Equivalents (MMcfe) |
| Permian Basin | 378,516 | 78,482 | 36,598 | 1,069,002 |
| Mid-Continent | 1,134,434 | 29,048 | 87,639 | 1,834,554 |
| Other | 4,002 | 268 | 40 | 5,851 |
| Total | 1,516,952 | 107,798 | 124,277 | 2,909,407 |

| | Year Ended December 31, 2014 | | | |
|---|---|---|---|---|
| | Gas (MMcf) | Oil (MBbl) | NGL (MBbl) | Total Gas Equivalents (MMcfe) |
| Permian Basin | 370,729 | 90,081 | 35,253 | 1,122,734 |
| Mid-Continent | 1,280,234 | 27,791 | 89,621 | 1,984,709 |
| Other | 15,770 | 1,120 | 399 | 24,880 |
| Total | 1,666,733 | 118,992 | 125,273 | 3,132,323 |

Year-end 2015 proved reserves declined by 7% to 2.9 Tcfe, compared to 3.1 Tcfe at year-end 2014. Proved natural gas reserves were 1.5 Tcf, oil contributed 0.65 Tcfe and NGLs accounted for 0.75 Tcfe. Our Mid-Continent's reserves accounted for 63% of total proved reserves with the remainder in the Permian Basin.

During 2015, we added 429 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin. In the Mid-Continent, we added 177 Bcfe. In the Permian Basin, we added 251 Bcfe. In addition, we had net positive performance revisions of 142 Bcfe. The performance revisions included 47 Bcfe for better than expected performance of PUD reserves converted to proved developed reserves during the year and positive adjustments of 95 Bcfe to previously booked PUD reserves.

During 2015, we had net negative reserve revisions of 276 Bcfe. The significant decrease in commodity prices seen in 2015 resulted in negative revisions of 399 Bcfe due to prices. In addition, 19 Bcfe of negative revisions was due to increases in operating expenses, which shortened the economic lives of properties. These decreases were partially offset by the 142 Bcfe of net positive performance revisions discussed above.

The process of estimating quantities of oil, gas and NGL reserves is complex. Significant decisions are required in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, contractual arrangements and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. See **SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)** in Item 8 of this report for further discussion regarding year-over-year changes in our proved reserves.

Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures. See ***Proved Reserves Estimation Procedures*** in Items 1 and 2 of this report for a discussion of our reserve estimation process.

***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 57% of our total production revenue for 2015. Gas sales accounted for 30% and NGL sales contributed 13%. A $1.00 per barrel change in our realized oil price would have resulted in an $18.7 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $16.9 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $13.1 million.

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| **Oil Prices:** | | | |
| Average realized sales price ($/Bbl) | $ 43.38 | $ 83.70 | $ 93.44 |
| Average WTI Midland price ($/Bbl) | $ 48.39 | $ 86.18 | $ 95.33 |
| Average WTI Cushing price ($/Bbl) | $ 48.80 | $ 93.01 | $ 97.97 |
| **Gas Prices:** | | | |
| Average realized sales price ($/Mcf) | $ 2.53 | $ 4.43 | $ 3.76 |
| Average Henry Hub price ($/Mcf) | $ 2.67 | $ 4.43 | $ 3.65 |
| **NGL Prices:** | | | |
| Average realized sales price ($/Bbl) | $ 13.75 | $ 33.14 | $ 29.36 |

During 2015, 2014 and 2013, approximately 84%, 80% and 80%, 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.

Prior to 2014, our average realized prices for gas and NGLs were net of certain processing fees. Beginning in 2014, these fees were no longer netted against realized prices. The resulting positive impact on gas prices for 2014 was $0.07 per Mcf. The positive impact on NGL prices was $3.54 per barrel. These positive impacts to prices were equally offset by increased transportation, processing and other operating costs. See Note 1, Basis of Presentation – *Oil, Gas and NGL Sales,* to the Consolidated Financial Statements in Item 8 of this report for additional information regarding these processing fees.

See **RESULTS OF OPERATIONS** below for analysis of the impact changes in realized prices had on our year-over-year revenues.

***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. At the end of 2015, we owned interests in 10,348 gross productive wells.

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.

The carrying value of our oil and gas properties subject to the ceiling test exceeded the calculated value of the ceiling limitation for each of the four quarters of 2015 resulting in aggregate impairments of $3.7 billion ($2.4 billion, net of tax). The impairments 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 early 2016 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 12-month period.

At December 31, 2015, commodity prices used in the ceiling calculation, based on the required trailing 12-month average, were $2.59 per Mcf of gas and $50.28 per barrel of oil, resulting in a pretax impairment of $965.3 million for the fourth quarter of 2015.To demonstrate the impact of commodity prices on the ceiling calculation, had average prices of $2.45 per Mcf of gas and $46.03 per barrel of oil been used instead, our pre-tax ceiling test impairment would have been approximately $1.259 billion at December 31, 2015. This would have increased our total 2015 impairments by approximately $294 million. The lower commodity prices were calculated based on a 12-month simple average of the commodity prices on the first day of the month for the 11 months ended February 2016 and the prices for February 2016 were used for the remaining month in the 12-month average.

The above calculation of the impact of lower commodity prices was prepared based on the presumption 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 write-downs or 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 in this paragraph 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 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 sales of production. Therefore, fluctuations in oil and gas prices will impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense. Conversely, lower prices generally have the effect of decreasing reserves, which increases depletion expense. The cost of replacing production also impacts our 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 impairments of our oil and gas properties, discussed above, resulted in lower DD&A rates in each quarter following the impairment.

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

Transportation, processing and other operating costs principally consist of expenditures to prepare and transport production from the wellhead, together with gas processing costs and costs to transport production to a specified sales point. 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

***2015 compared to 2014***

For the year ended December 31, 2015, we had a net loss of $2.4 billion ($25.92 per diluted share), compared to net income of $507.2 million ($5.78 per diluted share) for 2014. The net loss in 2015 was primarily a result of lower realized commodity prices, which also brought about impairments of our oil and gas properties. Year-over-year changes are discussed further in the analysis that follows.

| Production Revenue | Years Ended December 31, 2015 | Years Ended December 31, 2014 | Percent Change Between 2015 / 2014 | Price / Volume Change: Price | Volume | Total |
|---|---|---|---|---|---|---|
| **(in thousands or as indicated)** | | | | | | |
| Oil sales | $ 809,664 | $ 1,308,958 | (38)% | $ (752,492) | $ 253,198 | $ (499,294) |
| Gas sales | 428,227 | 687,930 | (38)% | (321,075) | 61,372 | (259,703) |
| NGL sales | 179,647 | 375,941 | (52)% | (253,292) | 56,998 | (196,294) |
| Total production revenue | $ 1,417,538 | $ 2,372,829 | (40)% | $ (1,326,859) | $ 371,568 | $ (955,291) |
| Total oil volume — thousand barrels | 18,663 | 15,639 | 19 % | | | |
| Oil volume — barrels per day | 51,132 | 42,846 | 19 % | | | |
| Percent of total equivalent production | 31 % | 30 % | | | | |
| Average oil price — per barrel | $ 43.38 | $ 83.70 | (48)% | | | |
| Total gas volume — MMcf | 168,987 | 155,128 | 9 % | | | |
| Gas volume — MMcf per day | 463.0 | 425.0 | 9 % | | | |
| Percent of total equivalent production | 47 % | 49 % | | | | |
| Average gas price — per Mcf | $ 2.53 | $ 4.43 | (43)% | | | |
| Total NGL volume — thousand barrels | 13,063 | 11,343 | 15 % | | | |
| NGL volume — barrels per day | 35,789 | 31,078 | 15 % | | | |
| Percent of total equivalent production | 22 % | 21 % | | | | |
| Average NGL price — per barrel | $ 13.75 | $ 33.14 | (59)% | | | |
| Total equivalent production — MMcfe | 359,343 | 317,022 | 13 % | | | |
| Total equivalent production volumes — MMcfe/d | 984.5 | 868.6 | 13 % | | | |

As reflected in the table above, our 2015 production revenue was 40% lower than that of 2014. Increased revenues from higher production volumes were more than offset by decreased revenues from lower realized commodity prices. The 13% year-over-year growth in production volumes was primarily due to our successful drilling programs in the Permian Basin and Mid-Continent region. See ***Exploration and Production Overview*** in Items 1 and 2 of this report for further information and a discussion of 2015 activity in these regions. See ***Revenues*** above, for information regarding realized prices.

Our 2015 aggregate production volumes were 359.3 Bcfe, comprised of 47% natural gas, 31% oil and 22% NGL. This compares to 2014 aggregate production volumes of 317.0 Bcfe, made up of 49% natural gas, 30% oil and 21% NGL.

*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 earn a fee for such services.

| | Years Ended December 31, | |
|---|---|---|
| | 2015 | 2014 |
| **Gas Gathering and Marketing** (in thousands): | | |
| Gas gathering and other revenues | $ 34,688 | $ 49,602 |
| Gas marketing revenues, net of related costs | $ 393 | $ 1,745 |

Fluctuations in revenues from gas gathering and marketing activities are a function of increases and decreases in volumes and prices associated with third party gas. In 2015, revenue from gas gathering declined by $14.9 million (30%), primarily due to lower realized prices which were partially offset by increased volumes.

Total operating costs and expenses (not including income tax expense) in 2015 were $5.19 billion compared to $1.61 billion for the prior year. As discussed above in ***Operating costs and expenses***, during 2015 our quarterly ceiling limitation calculations resulted in impairments totaling $3.72 billion. Excluding the effect of the impairments, our year-over-year operating costs and expenses decreased by $133.70 million. Analyses of the year-over-year differences are discussed below.

| | Years Ended December 31, | | Variance Between | Per Mcfe | |
|---|---|---|---|---|---|
| | 2015 | 2014 | 2015 / 2014 | 2015 | 2014 |
| **Operating costs and expenses** (in thousands): | | | | | |
| Impairment of oil and gas properties | $ 3,716,883 | $ — | $ 3,716,883 | N/A | N/A |
| DD&A | 778,923 | 806,021 | (27,098) | $ 2.17 | $ 2.54 |
| Asset retirement obligation | 9,121 | 10,082 | (961) | $ 0.03 | $ 0.03 |
| Production | 299,374 | 342,304 | (42,930) | $ 0.83 | $ 1.08 |
| Transportation, processing and other operating | 182,362 | 195,414 | (13,052) | $ 0.51 | $ 0.62 |
| Gas gathering and other | 38,138 | 35,113 | 3,025 | $ 0.11 | $ 0.11 |
| Taxes other than income | 84,764 | 128,793 | (44,029) | $ 0.24 | $ 0.41 |
| General and administrative | 74,688 | 81,160 | (6,472) | $ 0.21 | $ 0.26 |
| Stock compensation | 19,559 | 15,001 | 4,558 | $ 0.05 | $ 0.05 |
| (Gain) loss on derivative instruments, net | (11,246) | (3,762) | (7,484) | N/A | N/A |
| Other operating (income) expense, net | 856 | 116 | 740 | N/A | N/A |
| | $ 5,193,422 | $ 1,610,242 | $ 3,583,180 | | |

DD&A expense in 2015 decreased 3% compared to 2014. Increased expense due to higher 2015 production volumes was more than offset by lower DD&A rates in 2015. The impairments of our oil and gas properties, discussed above, 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 2016 average DD&A rate to fluctuate depending on average realized prices in 2016. 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.

Our year-over-year production costs decreased by 12.5% and accounted for 32.1% of the aggregate decrease in operating costs and expenses, excluding impairments. Production costs consist of lease operating expense and workover expense as follows:

| | Years Ended December 31, | | Variance Between | Per Mcfe | |
|---|---|---|---|---|---|
| **(in thousands)** | 2015 | 2014 | 2015 / 2014 | 2015 | 2014 |
| Lease operating expense | $ 249,744 | $ 276,395 | $ (26,651) | $ 0.70 | $ 0.87 |
| Workover expense | 49,630 | 65,909 | (16,279) | $ 0.13 | $ 0.21 |
| | $ 299,374 | $ 342,304 | $ (42,930) | $ 0.83 | $ 1.08 |

Lease operating expense in 2015 declined 9.6% compared to 2014. The decline was primarily a result of property divestitures, lower salt water disposal costs and decreased equipment and maintenance costs. These decreases were partially offset by increased expense related to new wells acquired and drilled. Increased production volumes in 2015 also contributed to the lower rate per Mcfe in 2015.

Workover expense decreased by 24.7% in 2015 compared to 2014. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Our 2015 year-over-year transportation, processing and other operating costs were 6.7% lower than those in 2014. These costs will vary by product type and region. In 2015, lower prices for natural gas and NGLs resulted in lower costs associated with fuel and processing fees, which were partially offset by higher processing volumes. Approximately 5% of the 2015 costs 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 year-over-year increase is due primarily to higher overall costs related to increased activity, which were largely offset by lower costs associated with product purchases.

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 comprised approximately 81% and 85% of these taxes for 2015 and 2014, respectively. The 34.2% decrease in 2015 taxes resulted primarily from lower production revenues due to lower realized commodity prices and accounted for 32.9% of the aggregate decrease in operating costs and expenses, excluding impairments.

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

| **(in thousands)** | **Years Ended December 31, 2015** | **2014** | **Variance Between 2015 / 2014** |
|---|---|---|---|
| G&A capitalized to oil and gas properties | $ 58,332 | $ 76,636 | $ (18,304) |
| G&A expense | 74,688 | 81,160 | (6,472) |
| | $ 133,020 | $ 157,796 | $ (24,776) |
| G&A expense per Mcfe | $ 0.21 | $ 0.26 | $ (0.05) |

During 2015, aggregate G&A declined 16% compared to 2014. Because of the adverse effect of lower commodity prices on our financial results, we reduced our expectations and accruals for short-term incentive-based cash compensation and benefits.

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 cost as follows:

| **(in thousands)** | **Years Ended December 31, 2015** | **2014** | **Variance Between 2015 / 2014** |
|---|---|---|---|
| Restricted stock awards | | | |
| Performance stock awards | $ 18,991 | $ 12,141 | $ 6,850 |
| Service-based stock awards | 14,547 | 13,607 | 940 |
| | 33,538 | 25,748 | 7,790 |
| Stock option awards | 2,803 | 3,057 | (254) |
| | 36,341 | 28,805 | 7,536 |
| Less amounts capitalized | (16,782) | (13,804) | (2,978) |
| Stock compensation | $ 19,559 | $ 15,001 | $ 4,558 |

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. The increase in 2015 stock compensation is primarily related to performance awards granted in December 2014, a portion of which were amortized during 2015. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts. See Note 6 to the Consolidated Financial Statements in Item 8 of this report for further discussion regarding our stock-based compensation.

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. Since 2009, we have chosen not to apply hedge accounting treatment to our derivative instruments. As a result, 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 changes in the fair value of our derivative contracts and the (gains) losses only from settlements during 2015 and 2014. See Note 4 to the Consolidated Financial Statements in Item 8 of this report for further details regarding our derivative instruments.

| | Years Ended December 31, | |
|---|---|---|
| **(in thousands)** | **2015** | **2014** |
| (Gain) loss on derivative instruments, net | $ (11,246) | $ (3,762) |
| Settlement (gains) losses | $ — | $ (7,641) |

*Other (income) and expense*

| | Years Ended December 31, | | Variance Between |
|---|---|---|---|
| **(in thousands)** | **2015** | **2014** | **2015 / 2014** |
| Interest expense | $ 85,746 | $ 72,865 | $ 12,881 |
| Capitalized interest | (30,589) | (35,925) | 5,336 |
| Other, net | (13,576) | (28,907) | 15,331 |
| | $ 41,581 | $ 8,033 | $ 33,548 |

The majority of our interest expense relates to interest on debt and amortization of financing costs. The 18% year-over-year increase is primarily due to the issuance of $750 million of senior notes in June of 2014. See ***Long-Term Debt*** below for further information regarding our debt.

We capitalize interest on non-producing leasehold costs, the in-progress costs of drilling and completing wells and constructing qualified assets. Capitalized interest will fluctuate based on our current rate of interest and the amount of costs on which interest is calculated.

Components of “other, net” consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment and supplies, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. Most of the 53% year-over-year decrease in income was due to lower net gains on transactions related to oil and gas well equipment and supplies and lower gains from sales of fixed assets.

An analysis of our oil and gas well equipment and supplies was performed and no impairment was required. However, the industry-wide decline in drilling operations has put downward pressure on the price of oil and gas well equipment and supplies. Further declines in future periods could cause us to recognize impairments on these assets. An impairment would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity. See Note 1, ***Oil and Gas Well Equipment and Supplies,*** of the Consolidated Financial Statements in Item 8 of this report for information regarding the carrying value of our oil and gas well equipment and supplies.

*Income Tax Expense*

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

| | Years Ended December 31, | |
|---|---|---|
| **(in thousands)** | **2015** | **2014** |
| Current tax expense | $ 14,710 | $ 404 |
| Deferred tax expense (benefit) | (1,388,146) | 298,293 |
| | $ (1,373,436) | $ 298,697 |
| Combined Federal and State effective income tax rate | 36.3 % | 37.1 % |

Our combined Federal and state effective tax rates differ from the statutory rate of 35% primarily due to state income taxes, non-deductible expenses and revisions. See Note 9 to the Consolidated Financial Statements in Item 8 of this report for further information regarding our income taxes.

## RESULTS OF OPERATIONS

***2014 compared to 2013***

Net income for the year ended December 31, 2014 was $507.2 million ($5.78 per diluted share), down 10% from $564.7 million ($6.47 per diluted share) for the previous year. In 2014, higher revenues from increased production volumes and higher realized prices received for gas and NGL production were offset by lower realized oil prices and increased operating expenses, primarily for DD&A and other operating, net expenses. In 2013, other operating, net included a significant reduction in our estimated exposure to certain litigation expense which had been accruing since 2008. Changes in our net income are discussed further in the analysis that follows.

| Production Revenue | Years Ended December 31, 2014 | Years Ended December 31, 2013 | Percent Change Between 2014 / 2013 | Price / Volume Change: Price | Price / Volume Change: Volume | Price / Volume Change: Total |
|---|---|---|---|---|---|---|
| **(in thousands or as indicated)** | | | | | | |
| Oil sales | $ 1,308,958 | $ 1,250,212 | 5 % | $ (152,324) | $ 211,070 | $ 58,746 |
| Gas sales | 687,930 | 471,045 | 46 % | 103,936 | 112,949 | 216,885 |
| NGL sales | 375,941 | 231,248 | 63 % | 42,877 | 101,816 | 144,693 |
| Total production revenue | $ 2,372,829 | $ 1,952,505 | 22 % | $ (5,511) | $ 425,835 | $ 420,324 |
| Total oil volume — thousand barrels | 15,639 | 13,380 | 17 % | | | |
| Oil volume — barrels per day | 42,846 | 36,659 | 17 % | | | |
| Percent of total equivalent production | 30 % | 32 % | | | | |
| Average oil price — per barrel | $ 83.70 | $ 93.44 | (10)% | | | |
| Total gas volume — MMcf | 155,128 | 125,248 | 24 % | | | |
| Gas volume — MMcf per day | 425.0 | 343.1 | 24 % | | | |
| Percent of total equivalent production | 49 % | 50 % | | | | |
| Average gas price — per Mcf | $ 4.43 | $ 3.76 | 18 % | | | |
| Total NGL volume — thousand barrels | 11,343 | 7,876 | 44 % | | | |
| NGL volume — barrels per day | 31,078 | 21,578 | 44 % | | | |
| Percent of total equivalent production | 21 % | 18 % | | | | |
| Average NGL price — per barrel | $ 33.14 | $ 29.36 | 13 % | | | |
| Total equivalent production — MMcfe | 317,022 | 252,787 | | | | |
| Total equivalent production volumes — MMcfe/d | 868.6 | 692.6 | 25 % | | | |

As reflected in the table above, our 2014 production revenue was 22% higher than that of 2013. Increased revenue from greater production volumes and higher realized prices for gas and NGL sales were partially offset by lower realized oil prices. See ***Revenues*** above, for a discussion regarding realized prices.

Our 2014 aggregate production volumes were 317.0 Bcfe, comprised of 49% natural gas, 30% oil and 21% NGL. This compares to 2013 aggregate production volumes of 252.8 Bcfe, made up of 50% natural gas, 32% oil and 18% NGL. The 25% year-over-year growth was primarily due to our successful drilling programs in the Permian Basin and Mid-Continent region in 2014.

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 earn a fee for such services.

| | Years Ended December 31, | |
|---|---|---|
| | 2014 | 2013 |
| **Gas Gathering and Marketing** (in thousands): | | |
| Gas gathering and other revenues | $ 49,602 | $ 45,441 |
| Gas marketing revenues, net of related costs | $ 1,745 | $ 105 |

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

Our total operating costs and expenses (not including income tax expense) in 2014 were $1.61 billion, an increase of 46% compared to $1.10 billion for the prior year. In 2013 we recorded a $142.8 million reduction in our estimated exposure to litigation expense, which had been accruing since 2008. Excluding the effect of the litigation expense estimate reduction, 2013 operating costs and expenses would have been $1.25 billion and the year-over-year increase would have been 29%. Analyses of the year-over-year differences are discussed below.

| | Years Ended December 31, | | Variance Between | Per Mcfe | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2014 / 2013 | 2014 | 2013 |
| **Operating costs and expenses** (in thousands): | | | | | |
| DD&A | $ 806,021 | $ 615,874 | $ 190,147 | $ 2.54 | $ 2.44 |
| Asset retirement obligation | 10,082 | 7,989 | 2,093 | $ 0.03 | $ 0.03 |
| Production | 342,304 | 286,742 | 55,562 | $ 1.08 | $ 1.13 |
| Transportation, processing and other operating | 195,414 | 93,580 | 101,834 | $ 0.62 | $ 0.37 |
| Gas gathering and other | 35,113 | 25,876 | 9,237 | $ 0.11 | $ 0.10 |
| Taxes other than income | 128,793 | 112,732 | 16,061 | $ 0.41 | $ 0.45 |
| General and administrative | 81,160 | 77,466 | 3,694 | $ 0.26 | $ 0.31 |
| Stock compensation | 15,001 | 14,279 | 722 | $ 0.05 | $ 0.06 |
| (Gain) loss on derivative instruments, net | (3,762) | 209 | (3,971) | N/A | N/A |
| Other operating (income) expense, net | 116 | (132,334) | 132,450 | N/A | N/A |
| | $ 1,610,242 | $ 1,102,413 | $ 507,829 | | |

Our 2014 DD&A expense increased 31% and accounted for 52% of the aggregate increase in operating costs and expenses, excluding the effect of the 2013 litigation expense estimate reversal. About 78% of the 2014 increase in DD&A was attributable to our higher production volumes. On a per Mcfe basis, 2014 DD&A increased by 4%. Our DD&A rate has increased because the per unit cost of adding new proved reserves has exceeded the net remaining book basis of proved reserves added in prior years.

Asset retirement obligation expense increased by 26% compared to 2013. Most of the increase resulted from higher plugging and abandonment costs incurred than had previously been estimated.

Our production costs consist of lease operating expense and workover expense as follows:

| | Years Ended December 31, | | Variance Between | Per Mcfe | |
|---|---|---|---|---|---|
| **(in thousands)** | 2014 | 2013 | 2014 / 2013 | 2014 | 2013 |
| Lease operating expense | $ 276,395 | $ 226,730 | $ 49,665 | $ 0.87 | $ 0.90 |
| Workover expense | 65,909 | 60,012 | 5,897 | $ 0.21 | $ 0.23 |
| | $ 342,304 | $ 286,742 | $ 55,562 | $ 1.08 | $ 1.13 |

Lease operating expense in 2014 increased 22% compared to 2013. Increased costs associated with putting new wells on production in 2014 accounted for approximately 65% of the $49.7 million year-over-year increase. Most of these costs were for salt water disposal, rental equipment, and chemicals and treating. We also experienced year-over-year increases for labor, and site maintenance and restoration. These increased expenditures were partially offset by decreased costs resulting from property divestitures during the year. The lower rate per Mcfe was primarily a function of increased production volumes in 2014.

Workover expense increased by 10% from 2013 to 2014. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period.

Our year-over-year transportation, processing and other operating costs increased significantly during 2014. These costs will vary by product type and region. During 2014, approximately half of the increase in costs resulted from increases in sales and processing volumes, contractual fees, compression charges and fuel costs. The remaining increase relates to the inclusion of certain processing fees that in previous years were treated as a reduction in realized sales prices for residue gas and NGLs. These costs accounted for approximately $0.16 per Mcfe for 2014. See Note 1, ***Revenue Recognition,*** *Oil, Gas and NGL Sales*, to the Consolidated Financial Statements in Item 8 of this report for additional information.

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

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based severance taxes comprise approximately 85% of these taxes. The 2014 year-over-year increase results primarily from higher severance taxes on greater oil, gas and NGL production volumes. While the aggregate tax amount increased by 14%, the rate per Mcfe declined 9% due to the increase in production volumes.

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

| | Years Ended December 31, | | Variance Between |
|---|---|---|---|
| **(in thousands)** | **2014** | **2013** | **2014 / 2013** |
| G&A capitalized to oil and gas properties | $ 76,636 | $ 74,691 | $ 1,945 |
| G&A expense | 81,160 | 77,466 | 3,694 |
| | $ 157,796 | $ 152,157 | $ 5,639 |
| G&A expense per Mcfe | $ 0.26 | $ 0.31 | $ (0.05) |

Our 2014 overall G&A cost increased modestly (4%) compared to 2013. In 2014, we experienced increased costs for salaries and benefits, consulting fees and higher rent related to new office facilities, which were partially offset by lower charitable contributions. The 16% decline in G&A expense per Mcfe is due to increased production volumes in 2014.

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

| (in thousands) | Years Ended December 31, 2014 | 2013 | Variance Between 2014 / 2013 |
|---|---|---|---|
| Restricted stock awards | | | |
| Performance stock awards | $ 12,141 | $ 11,105 | $ 1,036 |
| Service-based stock awards | 13,607 | 12,018 | 1,589 |
| | 25,748 | 23,123 | 2,625 |
| Stock option awards | 3,057 | 3,145 | (88) |
| | 28,805 | 26,268 | 2,537 |
| Less amounts capitalized | (13,804) | (11,989) | (1,815) |
| Stock compensation | $ 15,001 | $ 14,279 | $ 722 |

Expense associated with stock compensation will fluctuate based on the grant-date market value of the award and the number of shares granted. See Note 6 to the Consolidated Financial Statements in Item 8 of this report for further discussion regarding our stock-based compensation.

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments. Since 2009, we have chosen not to apply hedge accounting treatment to our derivative instruments. As a result, 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 the changes in fair value of our derivative contracts and the (gains) losses only from settlements during 2014 and 2013. All of our derivative contracts were settled as of December 31, 2014. See Note 4 to the Consolidated Financial Statements in Item 8 of this report for further details regarding our derivative instruments.

| (in thousands) | Years Ended December 31, 2014 | 2013 |
|---|---|---|
| (Gain) loss on derivative instruments, net | $ (3,762) | $ 209 |
| Settlement (gains) losses | $ (7,641) | $ 4,088 |

Other operating (income) expense, net consists primarily of costs related to various legal matters, most of which pertain to litigation and contract settlements, and title and royalty issues. In 2014, we have expense of $116 thousand versus income of $132.3 million for 2013. In 2013, based on a ruling from the Oklahoma Supreme Court, we reduced our estimated exposure to litigation expense that had been accruing since 2008 by $142.8 million. See Note 10 to the Consolidated Financial Statements in Item 8 of this report for further information regarding litigation matters.

*Other (income) and expense*

| (in thousands) | Years Ended December 31, 2014 | 2013 | Variance Between 2014 / 2013 |
|---|---|---|---|
| Interest expense | $ 72,865 | $ 54,973 | $ 17,892 |
| Capitalized interest | (35,925) | (31,517) | (4,408) |
| Other, net | (28,907) | (21,518) | (7,389) |
| | $ 8,033 | $ 1,938 | $ 6,095 |

Interest expense is primarily made up of interest on debt and amortization of financing costs. The 33% year-over-year increase is primarily due to the issuance of $750 million of senior notes in June of 2014. See ***Long-Term Debt*** below for further information regarding our debt.

We capitalize interest on non-producing leasehold costs, the in-progress costs of drilling and completing wells and constructing qualified assets. The 14% increase in 2014 capitalized interest compared to 2013 was a result of higher costs on which interest was calculated in 2014.

Components of "other, net" consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment and supplies, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. Most of the 34% year-over-year increase was due to net gains on transactions related to oil and gas well equipment and supplies.

*Income Tax Expense*

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

| | Years Ended December 31, | |
|---|---|---|
| **(in thousands)** | **2014** | **2013** |
| Current tax expense (benefit) | $ 404 | $ (689) |
| Deferred tax expense | 298,293 | 329,700 |
| | $ 298,697 | $ 329,011 |
| Combined Federal and state effective income tax rate | 37.1 % | 36.8 % |

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 in Item 8 of this report for further information regarding our income taxes.

## LIQUIDITY AND CAPITAL RESOURCES

***Overview***

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

In May 2015, we completed an underwritten public offering of 6.9 million shares of our common stock, 900,000 of which were issued pursuant to an overallotment option to purchase additional shares granted to the underwriters. The stock was sold to the public at $109.00 per share. After deducting customary underwriting discounts, net proceeds of approximately $730 million were received from this offering. Our intent continues to be to use the net proceeds for general corporate purposes and to fund drilling and completion activity.

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 2015 earnings.

We deal with volatility in commodity prices primarily by maintaining flexibility in our capital investment program. We have a diversified drilling portfolio and limited long-term commitments, which enables us to respond quickly to industry volatility. See ***Capital Expenditures*** below for information regarding our 2015 exploration and development (E&D) investment program.

From time to time we may enter into hedging agreements. We entered 2015 with no hedges outstanding. During the third quarter of 2015 and subsequently, we entered into derivative contracts covering a portion of our 2016 and 2017 production. See Note 4 to the Consolidated Financial Statements in Item 8 of this report for information regarding our derivative instruments. Management will decide whether to enter into derivative contracts depending on their view of underlying supply and demand trends, changes in the oil and gas futures markets and other considerations.

We believe our conservative use of leverage and strong balance sheet will mitigate our exposure to lower prices. Cash and cash equivalents at December 31, 2015 was $779.4 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 December 31, 2015 was 35%. 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 $2.8 billion. Management believes that this non-GAAP measure is useful information as it is a common statistic used in the investment community to assist with the 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 in 2016 and beyond.

***Sources and Uses of Cash***

Our primary sources of liquidity and capital resources are operating cash flow, borrowings under our Credit Facility, asset sales and occasional public financings. Our primary uses of funds are expenditures for exploration and development, leasehold and property acquisitions, other capital expenditures, debt service and cash dividends paid to holders of our common stock.

The significant decline in year-over-year realized prices for our oil and natural gas production adversely impacted our operating cash flow for 2015 and consequently reduced the amount of cash available for exploration and development activities. See ***Market Conditions*** above for further information regarding prevailing economic conditions.

The following table presents our sources and uses of cash and cash equivalents from 2013 to 2015. Capital expenditures are presented on a cash basis. These amounts differ from capital expenditures (including accruals) that are referred to elsewhere in this report.

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2015** | **2014** | **2013** |
| Sources of cash and cash equivalents: | | | |
| Operating cash flow | $ 691,500 | $ 1,619,365 | $ 1,324,348 |
| Sales of oil and gas and other assets | 41,031 | 458,394 | 93,164 |
| Net increase in bank debt | — | — | 174,000 |
| Increase in other long-term debt | — | 750,000 | — |
| Proceeds from sale of common stock | 752,100 | — | — |
| Proceeds from exercise of stock options and other | 21,439 | 11,898 | 14,494 |
| **Total sources of cash and cash equivalents** | 1,506,070 | 2,839,657 | 1,606,006 |
| Uses of cash and cash equivalents: | | | |
| Oil and gas capital expenditures | (979,044) | (2,108,250) | (1,572,288) |
| Other capital expenditures | (70,592) | (90,611) | (51,913) |
| Net decrease in bank debt | — | (174,000) | — |
| Financing and underwriting fees | (24,633) | (11,616) | (100) |
| Dividends paid | (58,281) | (53,849) | (46,712) |
| **Total uses of cash and cash equivalents** | (1,132,550) | (2,438,326) | (1,671,013) |
| **Net increase (decrease) in cash and cash equivalents** | $ 373,520 | $ 401,331 | $ (65,007) |
| Cash and cash equivalents at end of year | $ 779,382 | $ 405,862 | $ 4,531 |

***Analysis of Cash Flow Changes (See the Consolidated Statements of Cash Flows in Item 8 of this report.)***

Net cash flow provided by operating activities (operating cash flow) for 2015 was $691.5 million, down 57% from $1.6 billion for 2014. The $927.9 million decrease was primarily a result of a net decrease in production revenue from lower realized commodity prices in 2015. The decrease in production revenue was partially offset by lower net operating costs in 2015. The 22% increase in 2014 operating cash flow compared to 2013 was mostly due to increased revenues from greater production volumes and higher realized prices for natural gas and NGLs, which were partially offset by lower realized oil prices and increased operating expenses. See **RESULTS OF OPERATIONS** above for details regarding year-over-year changes in production revenues and operating expenses.

In 2015, net cash flow used for investing activities was $1.0 billion, compared to $1.7 billion for 2014 and $1.5 billion for 2013. In 2015, our E&D and other capital investments were $1.1 billion, which were partially offset by asset sales of $41.0 million. Our 2014 E&D and other capital investments were $2.2 billion, which were partially offset by proceeds from asset sales of $458 million. For 2013, our E&D and other capital expenditures were $1.6 billion, which were partially offset by asset sales of $93.2 million.

Net cash flow provided by financing activities in 2015 was $690.6 million compared to $522.4 million in 2014 and $141.7 million in 2013. During 2015, cash provided by financing activities included approximately $730 million of net proceeds from the sale of common stock and $21.4 million of proceeds from issuance of common stock from employee option exercises and other. These cash flows were partially offset by dividend payments of $58.3 million and $2.5 million of financing costs.

In 2014, net cash flow provided by financing activities included the issuance of $750.0 million of senior notes and $11.9 million of proceeds from the issuance of common stock from employee option exercises, which were partially offset by payments of $174.0 million on our Credit Facility, $11.6 million for financing costs and dividend payments of $53.8 million.

In 2013, financing activity cash inflows came from net bank borrowings of $174.0 million together with net proceeds from the issuance of common stock from employee option exercises of $14.5 million, which were partially offset by $46.7 million of dividend payments.

*Reconciliation of Adjusted Cash Flow from Operations*

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2015** | **2014** | **2013** |
| Net cash provided by operating activities | $ 691,500 | $ 1,619,365 | $ 1,324,348 |
| Change in operating assets and liabilities | 52,082 | 14,847 | 63,840 |
| Adjusted cash flow from operations | $ 743,582 | $ 1,634,212 | $ 1,388,188 |

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

***Capital Expenditures***

The following table reflects capitalized expenditures for oil and gas acquisitions, exploration and development activities and property sales:

| | Years Ended December 31, | |
|---|---|---|
| **(in thousands)** | **2015** | **2014** |
| Acquisitions: | | |
| Proved | $ 30 | $ 138,508 |
| Unproved | 6,666 | 111,225 |
| Net purchase price adjustments (*) | (11,653) | — |
| | (4,957) | 249,733 |
| Exploration and development: | | |
| Land & seismic | 52,049 | 176,061 |
| Exploration | 1,073 | 40,084 |
| Development | 823,830 | 1,664,877 |
| | 876,952 | 1,881,022 |
| Property sales | (41,276) | (446,107) |
| | $ 830,719 | $ 1,684,648 |

(*) The negative amount in 2015 reflects purchase price adjustments related to an acquisition in the second quarter of 2014.

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

Because of lower commodity prices, we reduced our capital expenditures for 2015 by 53% compared to 2014. Our 2016 E&D capital investment is presently expected to range from $600-$650 million, a 29% reduction from 2015 at the midpoint. Our expectation is that 65% of our 2016 capital investment will be in the Permian Basin with the remaining 35% in the Mid-Continent region. Based on our current development plans, our estimates of proved reserves have yet to be materially impacted by our response to lower prices.

As has been our historical practice, we regularly review 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 fund our 2016 capital program with cash on hand at December 31, 2015 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.

During 2015, approximately 55% of our $877.0 million E&D expenditures were in the Permian Basin and 43% were in our Mid-Continent region. We participated in the drilling and completion of 219 gross (99 net) wells, 123 of which we operated.

Of the total wells drilled, 85 gross (60 net) were in the Permian Basin and 134 gross (39 net) were in the Mid-Continent region. At year-end 49 gross (20 net) wells were awaiting completion with 12 gross (7 net) in the Permian Basin and 37 gross (13 net) in the Mid-Continent region. See Items 1 and 2 of this report for further information regarding our wells drilled and other information regarding our oil and gas properties.

In the ordinary course of business we actively evaluate opportunities to purchase properties that we believe could benefit from our technical capabilities, particularly in our core areas of operations. We also evaluate our non-core property holdings for potential divestitures. For further information on our property acquisitions and dispositions, see Note 12 to the Consolidated Financial Statements in Item 8 of this report.

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 2015, our total assets decreased $3.5 billion (40%) to $5.2 billion, compared to $8.7 billion at December 31, 2014. The decrease was mainly attributable to the $3.7 billion impairment of our oil and gas properties, which was partially offset by a $373.5 million increase in cash.

Total liabilities at year-end 2015 were $2.4 billion, down $1.8 billion (42%) from $4.2 billion at year-end 2014. Of the $1.8 billion decrease, $366.3 million is the result of a decrease in total current liabilities primarily related to our oil and gas operations and drilling activity. Almost all of the remaining decrease is due to a $1.4 billion decline in deferred income taxes, mainly attributable to our net loss for 2015.

On December 31, 2015, stockholders' equity totaled $2.8 billion, a decrease of $1.7 billion (38%) from $4.5 billion at December 31, 2014. The decrease resulted from our 2015 net loss of $2.4 billion and from dividends of $59.3 million. These decreases were only partially offset by net proceeds of $730.0 million from our second quarter common stock offering.

The 2015 decreases in our total assets, liabilities and stockholders' equity and our net loss for the year resulted primarily from the $3.7 billion aggregate impairment of our oil and gas properties. Quarterly impairments resulted from the continued impact of lower prices on the present value of future cash flows from our proved reserves used in our full cost pool ceiling limitation calculation. As noted above under ***Operating costs and expenses***, 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 and various components of our balance sheet.

***Long-Term Debt***

Long-term debt at year end 2015 and 2014 consisted of the following:

| | December 31, 2015 | | December 31, 2014 | |
|---|---|---|---|---|
| **(in thousands)** | **Principal** | **Unamortized Debt Issuance Costs** | **Principal** | **Unamortized Debt Issuance Costs** |
| 5.875% Senior Notes, due May 1, 2022 | $ 750,000 | $ 6,978 | $ 750,000 | $ 8,343 |
| 4.375% Senior Notes, due June 1, 2024 | 750,000 | 7,402 | 750,000 | 8,481 |
| Total long-term debt | $ 1,500,000 | $ 14,380 | $ 1,500,000 | $ 16,824 |

At December 31, 2015 and 2014 we had no bank debt outstanding. All of our long-term debt is senior unsecured debt and is, therefore, *pari passu* with respect to the payment of both principal and interest. At December 31, 2015, we adopted FASB ASU 2015-15 regarding the balance sheet presentation of debt issuance costs. See Note 3 to the Consolidated Financial Statements in Item 8 of this report for further information.

*Bank Debt*

In October 2015, we entered into a new senior unsecured revolving credit facility (Credit Facility) with an initial aggregate commitment from the lenders of $1.0 billion. We have the option to increase the commitment to $1.25 billion at any time. Unlike the prior credit facility, the new 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 December 31, 2015, we had letters of credit outstanding of $2.5 million under the Credit Facility, leaving an unused borrowing availability of $997.5 million. During 2015, we had average daily bank debt outstanding of $27.4 thousand, compared to $132.6 million in 2014. Our highest amount of bank borrowings outstanding during 2015 was $10.0 million in May. During 2014, the highest amount of outstanding bank borrowings was $515.0 million also 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%. For further information regarding the terms of the Credit Facility see Note 3 to the Consolidated Financial Statements in Item 8 of this report.

*Senior Notes*

Interest on our senior notes is payable semi-annually. Each of our outstanding senior notes is governed by an indenture containing customary covenants, events of default and other restrictive provisions. For further information regarding our senior notes see Note 3 to the Consolidated Financial Statements in Item 8 of this report.

***Working Capital Analysis***

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

At December 31, 2015, we had working capital of $667.9 million, an increase of $512.4 million compared to working capital of $155.5 million at December 31, 2014.

Working capital increases consisted primarily of the following:

- Cash and cash equivalents increased by $373.5 million primarily from our second quarter common stock offering.

- Operations-related accounts payable and accrued liabilities decreased $222.3 million.

- Accrued liabilities related to our E&D expenditures decreased by $144.2 million.

Increases in working capital were partially offset by the following:

- Operations-related accounts receivable decreased $186.3 million

- Oil and gas well equipment and supplies decreased by $35.2 million.

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

***Dividends***

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| Dividend declared (in millions) | $ 59.3 | $ 55.7 | $ 48.4 |
| Dividend per share | $ 0.64 | $ 0.64 | $ 0.56 |

***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 December 31, 2015, our material off-balance sheet arrangements included operating lease agreements, which are customary in the oil and gas industry.

***Contractual Obligations and Material Commitments***

At December 31, 2015, we had the following contractual obligations and material commitments.

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| **Contractual obligations:** | **Total** | **1 Year or Less** | **2 - 3 Years** | **4 - 5 Years** | **More than 5 Years** |
| **(in thousands)** | | | | | |
| Long-term debt (1) | $ 1,500,000 | $ — | $ — | $ — | $ 1,500,000 |
| Fixed-Rate interest payments (1) | 565,312 | 76,876 | 153,750 | 153,750 | 180,936 |
| Operating leases | 96,710 | 9,248 | 18,744 | 18,545 | 50,173 |
| Drilling commitments (2) | 223,260 | 222,940 | 320 | — | — |
| Asset retirement obligation (3) | 164,105 | 10,248 | — (3) | — (3) | — (3) |
| Other liabilities (4) | 130,938 | 38,523 | 62,555 | 2,027 | 27,833 |
| Firm Transportation | 31,813 | 7,557 | 10,871 | 4,118 | 9,267 |

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

(2) We have drilling commitments of $201.7 million, consisting of obligations to finish drilling and completing wells in progress at December 31, 2015. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $21.6 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 includes the estimated value of our commitment associated with our benefit obligations and other miscellaneous commitments.

At December 31, 2015, we had firm sales contracts to deliver approximately 56 Bcf of natural gas over the next three years. If this gas is not delivered, our financial commitment would be approximately $116.7 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 $203.0 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 $12.4 million. Of this total, we have accrued a liability of $9.7 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 $36.3 million. We currently 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.

***2016 Outlook***

In 2016, our total production is projected to average 890-930 MMcfe per day.

As a result of continued declines in commodity prices we have reduced our planned drilling activity. Our 2016 E&D capital investment is expected to decrease from $877.0 million in 2015 to $600-$650 million in 2016, a 29% reduction at midpoint. Our capital investment is expected to be allocated 65% to our Permian Basin and 35% to the Mid-Continent region. Investments in gathering and processing infrastructure and other fixed assets are expected to approximate $50 million.

As has been our historical practice, we regularly review 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.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Discussion and analysis of our financial condition and results of operation are based on our Consolidated Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We analyze and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

A complete list of our significant accounting policies are described in Note 1 to our Consolidated Financial Statements in Item 8 of this report. We have identified the following policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

***Oil and Gas Reserves***

The process of estimating quantities of oil and gas reserves is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time due to numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures.

At year-end 2015, 25% of our total proved reserves are categorized as proved undeveloped reserves, or PUDs. Our reserve engineers review and revise these reserve estimates regularly, as new information becomes available.

We use the units-of-production method to amortize the cost associated with our oil and gas properties. Changes in estimates of reserve quantities and commodity prices will cause corresponding changes in depletion expense, or in some cases, a full cost ceiling impairment charge in the period of the revision. See ***Full Cost Accounting*** below for further information regarding the ceiling limitation calculation. See **SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)** in Item 8 of this report for additional reserve data.

***Full Cost Accounting***

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

Companies that follow the full cost accounting method are required to make a quarterly ceiling test calculation. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized and all related tax effects. We currently do not have any unproven properties being amortized. Revenue calculations in the reserves are based on the unweighted average first-day-of-the-month commodity price for the prior 12 months. Changes in proved reserve estimates (whether based upon quantity revisions or commodity price) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be expensed.

Quarterly ceiling tests are primarily impacted by commodity prices, reserve quantities added and produced, overall exploration and development costs, depletion expense and deferred taxes. For each of the four quarters ended December 31, 2015, the carrying value of our oil and gas properties subject to the ceiling test exceeded the calculated value of the ceiling limitation, and we recognized aggregate impairments of $3.7 billion ($2.4 billion, net of tax). These impairments resulted primarily from the 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 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. See ***Operating costs and expenses*** above for a complete discussion of our 2015 ceiling impairments.

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 and stockholders' equity. Any recorded impairment of oil and gas properties is not reversible at a later date.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement obligations, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities and commodity prices will cause corresponding changes in depletion expense in periods subsequent to these changes. The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized resulting from the determination of proved reserves or changes in our development plans. To the extent that the evaluation indicates these properties will not be developed, their cost is added to the capitalized costs to be amortized. See Note 1 to our Consolidated Financial statements in Item 8 of this report for information regarding the effect of a ceiling impairment on our depletion rate. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

***Goodwill***

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. We first assess qualitative factors to determine whether it is more likely than not (with a greater than 50% threshold) that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. If goodwill is determined to be impaired, then it is written down to a calculated fair value by charging the impairment to expense.

We evaluate our goodwill for impairment in the fourth quarter of each year or whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. Based upon our qualitative assessment at December 31, 2015, goodwill was not impaired. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable.

***Contingencies***

A provision for contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes subjective judgment. In many cases, this judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. We closely monitor known and potential legal, environmental, and other contingencies periodically to determine if we should record losses. Actual costs can vary from our estimates for a variety of reasons. See Note 10 to the Consolidated Financial Statements in Item 8 of this report for further information regarding litigation and other commitments and contingencies.

At December 31, 2015, we had not made any accruals related to environmental remediation costs. However, we may be required to make such estimates in future periods if applicable laws and regulations change or if the interpretation or administration of laws and regulations change. Other factors, such as unanticipated construction problems or identification of areas of contaminated soil or groundwater, could also cause us to accrue for such costs.

***Asset Retirement Obligation***

Our asset retirement obligation represents the estimated present value of the amount we will incur to retire long-lived assets at the end of their productive lives, in accordance with applicable state laws. Our asset retirement obligation is determined by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of inception with an offsetting increase in the carrying amount of the related long-lived asset. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset.

Asset retirement liability is determined using significant assumptions including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of assets and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Because of the subjectivity of assumptions, the costs to ultimately retire our wells may vary significantly from prior estimates. See Note 8 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding our asset retirement obligations.

***Income Taxes***

Our oil and gas exploration and production operations are subject to taxation on income in numerous jurisdictions. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices).

The company regularly assesses and, if required, establishes accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions where the company operates. See Note 9 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding our income taxes.

***Recently Issued Accounting Standards***

Please refer to Note 1, Basis of Presentation and Summary of Significant Accounting Policies – *Recently Issued Accounting Standards,* to the Consolidated Financial Statements in Item 8 of this report for a discussion of recent accounting pronouncements and their anticipated effect on our business.

## ITEM 7A. 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 57% of our total production revenue for 2015. Gas sales accounted for 30% and NGL sales contributed 13%. A $1.00 per barrel change in our realized oil price would have resulted in an $18.7 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $16.9 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $13.1 million. See Market Conditions in Item 7 of this report for further information.

We periodically enter into financial derivative contracts to hedge a portion of our price risk associated with our future oil and gas production. At December 31, 2015, we have gas collars in place for the years 2016 and 2017 with a total fair value of $4.5 million. We have three-way oil collars in place for the year 2016 with a total fair value of $6.7 million. Subsequent to December 31, 2015, we entered into additional gas collars. See Note 4 to the Consolidated Financial Statements in Item 8 of 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 in our gain (loss) on mark-to-market derivatives in 2015 of $1.0 million. 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 in our gain (loss) on mark-to-market derivatives in 2015 of $1.1 million.

***Interest Rate Risk***

At December 31, 2015, 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 receivables, accounts payable and accrued liabilities because of the short-term maturity of such instruments. See Note 3 and Note 5 to the Consolidated Financial Statements in Item 8 of this report for additional information regarding debt.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### CIMAREX ENERGY CO.

### INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTAL SCHEDULES



All other supplemental information and schedules have been omitted because they are not applicable or the information required is shown in the consolidated financial statements or related notes thereto.

**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Stockholders

Cimarex Energy Co.:

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries (the Company) as of December 31, 2015 and 2014, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three year period ended December 31, 2015. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Cimarex Energy Co. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Cimarex Energy Co. and subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 23, 2016 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver, Colorado
February 23, 2016

**CIMAREX ENERGY CO.**

**CONSOLIDATED BALANCE SHEETS**

**(in thousands, except share and per share information)**

| | December 31, 2015 | December 31, 2014 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 779,382 | $ 405,862 |
| Accounts receivable: | | |
| Trade, net of allowance | 81,888 | 134,443 |
| Oil and gas sales, net of allowance | 136,537 | 259,220 |
| Gas gathering, processing, and marketing, net of allowance | 6,935 | 18,009 |
| Other | 38 | 436 |
| Oil and gas well equipment and supplies | 54,579 | 89,780 |
| Deferred income taxes | — | 13,475 |
| Derivative instruments | 10,745 | — |
| Prepaid Expenses | 7,036 | 9,356 |
| Other current assets | 790 | 1,223 |
| Total current assets | 1,077,930 | 931,804 |
| Oil and gas properties at cost, using the full cost method of accounting: | | |
| Proved properties | 15,546,948 | 14,402,064 |
| Unproved properties and properties under development, not being amortized | 440,166 | 759,149 |
| | 15,987,114 | 15,161,213 |
| Less—accumulated depreciation, depletion and amortization and impairment | (12,710,968) | (8,257,502) |
| Net oil and gas properties | 3,276,146 | 6,903,711 |
| Fixed assets, less accumulated depreciation of $207,173 and $175,453 | 230,009 | 211,031 |
| Goodwill | 620,232 | 620,232 |
| Derivative instruments | 501 | — |
| Other assets, net | 38,468 | 41,691 |
| | $ 5,243,286 | $ 8,708,469 |
| **Liabilities and Stockholders' Equity** | | |
| Current liabilities: | | |
| Accounts payable: | | |
| Trade | $ 53,384 | $ 102,276 |
| Gas gathering, processing, and marketing | 13,431 | 35,775 |
| Accrued liabilities: | | |
| Exploration and development | 56,721 | 200,929 |
| Taxes other than income | 17,545 | 26,950 |
| Other | 173,242 | 219,505 |
| Revenue payable | 95,744 | 190,892 |
| Total current liabilities | 410,067 | 776,327 |
| Long-term debt: | | |
| Principal | 1,500,000 | 1,500,000 |
| Less—unamortized debt issuance costs | (14,380) | (16,824) |
| Long-term debt, net | 1,485,620 | 1,483,176 |
| Deferred income taxes | 352,705 | 1,754,706 |
| Asset retirement obligation | 153,857 | 159,792 |
| Other liabilities | 43,359 | 33,836 |
| Total liabilities | 2,445,608 | 4,207,837 |
| 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, 94,820,570 and 87,592,535 shares issued, respectively | 948 | 876 |
| Paid-in capital | 2,762,976 | 1,997,080 |
| Retained earnings | 33,313 | 2,501,574 |
| Accumulated other comprehensive income | 441 | 1,102 |
| | 2,797,678 | 4,500,632 |
| | $ 5,243,286 | $ 8,708,469 |

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

# CIMAREX ENERGY CO.

## CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

### (in thousands, except per share data)

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Revenues: | | | |
| Oil sales | $ 809,664 | $ 1,308,958 | $ 1,250,212 |
| Gas sales | 428,227 | 687,930 | 471,045 |
| NGL Sales | 179,647 | 375,941 | 231,248 |
| Gas gathering and other | 34,688 | 49,602 | 45,441 |
| Gas marketing, net of related costs of $144,673, $256,836 and $187,772 respectively | 393 | 1,745 | 105 |
| | 1,452,619 | 2,424,176 | 1,998,051 |
| Costs and expenses: | | | |
| Impairment of oil and gas properties | 3,716,883 | — | — |
| Depreciation, depletion and amortization | 778,923 | 806,021 | 615,874 |
| Asset retirement obligation | 9,121 | 10,082 | 7,989 |
| Production | 299,374 | 342,304 | 286,742 |
| Transportation, processing, and other operating | 182,362 | 195,414 | 93,580 |
| Gas gathering and other | 38,138 | 35,113 | 25,876 |
| Taxes other than income | 84,764 | 128,793 | 112,732 |
| General and administrative | 74,688 | 81,160 | 77,466 |
| Stock compensation | 19,559 | 15,001 | 14,279 |
| (Gain) loss on derivative instruments, net | (11,246) | (3,762) | 209 |
| Other operating (income) expense, net | 856 | 116 | (132,334) |
| | 5,193,422 | 1,610,242 | 1,102,413 |
| Operating income (loss) | (3,740,803) | 813,934 | 895,638 |
| Other (income) and expense: | | | |
| Interest expense | 85,746 | 72,865 | 54,973 |
| Capitalized interest | (30,589) | (35,925) | (31,517) |
| Other, net | (13,576) | (28,907) | (21,518) |
| Income (loss) before income tax | (3,782,384) | 805,901 | 893,700 |
| Income tax expense (benefit) | (1,373,436) | 298,697 | 329,011 |
| Net income (loss) | $ (2,408,948) | $ 507,204 | $ 564,689 |
| Earnings (loss) per share to common stockholders: | | | |
| Basic | | | |
| Distributed | $ 0.64 | $ 0.64 | $ $0.56 |
| Undistributed | (26.56) | 5.15 | 5.92 |
| | $ (25.92) | $ 5.79 | $ 6.48 |
| Diluted | | | |
| Distributed | $ 0.64 | $ 0.64 | $ $0.56 |
| Undistributed | (26.56) | 5.14 | 5.91 |
| | $ (25.92) | $ 5.78 | $ 6.47 |
| Comprehensive income (loss): | | | |
| Net income (loss) | $ (2,408,948) | $ 507,204 | $ 564,689 |
| Other comprehensive income (loss): | | | |
| Change in fair value of investments, net of tax | (661) | (87) | 715 |
| Total comprehensive income (loss) | $ (2,409,609) | $ 507,117 | $ 565,404 |

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

## CIMAREX ENERGY CO.

## CONSOLIDATED STATEMENTS OF CASH FLOWS

**(in thousands)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Cash flows from operating activities: | | | |
| Net income (loss) | $ (2,408,948) | $ 507,204 | $ 564,689 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Impairments and other valuation losses | 3,716,883 | — | — |
| Depreciation, depletion and amortization | 778,923 | 806,021 | 615,874 |
| Asset retirement obligation | 9,121 | 10,082 | 7,989 |
| Deferred income taxes | (1,388,146) | 298,293 | 329,700 |
| Stock compensation | 19,559 | 15,001 | 14,279 |
| (Gain) loss on derivative instruments | (11,246) | (3,762) | 209 |
| Settlements on derivative instruments | — | 7,641 | (4,088) |
| Changes in non-current assets and liabilities | 23,230 | (2,440) | (141,215) |
| Other, net | 4,206 | (3,828) | 751 |
| Changes in operating assets and liabilities: | | | |
| Receivables, net | 186,699 | (35,133) | (64,780) |
| Other current assets | 37,954 | (25,428) | 14,234 |
| Accounts payable and other current liabilities | (276,735) | 45,714 | (13,294) |
| Net cash provided by operating activities | 691,500 | 1,619,365 | 1,324,348 |
| Cash flows from investing activities: | | | |
| Oil and gas expenditures | (979,044) | (2,108,250) | (1,572,288) |
| Sales of oil and gas assets | 39,853 | 449,981 | 61,503 |
| Sales of other assets | 1,178 | 8,413 | 31,661 |
| Other capital expenditures | (70,592) | (90,611) | (51,913) |
| Net cash used by investing activities | (1,008,605) | (1,740,467) | (1,531,037) |
| Cash flows from financing activities: | | | |
| Net bank debt borrowings | — | (174,000) | 174,000 |
| Proceeds from other long-term debt | — | 750,000 | — |
| Proceeds from sale of common stock | 752,100 | — | — |
| Financing and underwriting fees | (24,633) | (11,616) | (100) |
| Dividends paid | (58,281) | (53,849) | (46,712) |
| Proceeds from exercise of stock options and other | 21,439 | 11,898 | 14,494 |
| Net cash provided by financing activities | 690,625 | 522,433 | 141,682 |
| Net change in cash and cash equivalents | 373,520 | 401,331 | (65,007) |
| Cash and cash equivalents at beginning of period | 405,862 | 4,531 | 69,538 |
| Cash and cash equivalents at end of period | $ 779,382 | $ 405,862 | $ 4,531 |

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

## CIMAREX ENERGY CO.

## CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

**(in thousands)**

| | Common Stock | | Paid-in | Retained | Accumulated Other Comprehensive | Total Stockholders' |
|---|---|---|---|---|---|---|
| | Shares | Amount | Capital | Earnings | Income (loss) | Equity |
| Balance, December 31, 2012 | 86,596 | $ 866 | $ 1,939,628 | $ 1,533,768 | $ 474 | $ 3,474,736 |
| Dividends | — | — | — | (48,423) | — | (48,423) |
| Net Income | — | — | — | 564,689 | — | 564,689 |
| Unrealized change in fair value of investments, net of tax | — | — | — | — | 715 | 715 |
| Issuance of restricted stock awards | 579 | 6 | (6) | — | — | — |
| Common stock reacquired and retired | (153) | (1) | (10,100) | — | — | (10,101) |
| Restricted stock forfeited and retired | (171) | (2) | 2 | — | — | — |
| Exercise of stock options | 276 | 3 | 14,491 | — | — | 14,494 |
| Vesting of restricted stock units | 25 | — | — | — | — | — |
| Stock-based compensation | — | — | 26,098 | — | — | 26,098 |
| Balance, December 31, 2013 | 87,152 | $ 872 | $ 1,970,113 | $ 2,050,034 | $ 1,189 | $ 4,022,208 |
| Dividends | — | — | — | (55,664) | — | (55,664) |
| Net Income | — | — | — | 507,204 | — | 507,204 |
| Unrealized change in fair value of investments, net of tax | — | — | — | — | (87) | (87) |
| Issuance of restricted stock awards | 487 | 4 | (4) | — | — | — |
| Common stock reacquired and retired | (123) | (1) | (13,559) | — | — | (13,560) |
| Restricted stock forfeited and retired | (135) | (1) | 1 | — | — | — |
| Exercise of stock options | 211 | 2 | 11,896 | — | — | 11,898 |
| Stock-based compensation | — | — | 28,633 | — | — | 28,633 |
| Balance, December 31, 2014 | 87,592 | $ 876 | $ 1,997,080 | $ 2,501,574 | $ 1,102 | $ 4,500,632 |
| Dividends | — | — | — | (59,313) | — | (59,313) |
| Net Income (loss) | — | — | — | (2,408,948) | — | (2,408,948) |
| Unrealized change in fair value of investments, net of tax | — | — | — | — | (661) | (661) |
| Issuance of common stock | 6,900 | 69 | 729,468 | — | — | 729,537 |
| Issuance of restricted stock awards | 471 | 5 | (5) | — | — | — |
| Common stock reacquired and retired | (194) | (2) | (21,238) | — | — | (21,240) |
| Restricted stock forfeited and retired | (90) | (1) | 1 | — | — | — |
| Exercise of stock options | 142 | 1 | 8,450 | — | — | 8,451 |
| Stock-based compensation | — | — | 36,232 | — | — | 36,232 |
| Stock-based compensation tax benefit | — | — | 12,988 | — | — | 12,988 |
| Balance, December 31, 2015 | 94,821 | $ 948 | $ 2,762,976 | $ 33,313 | $ 441 | $ 2,797,678 |

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

**CIMAREX ENERGY CO.**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

## 1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cimarex Energy Co., a Delaware corporation, is an independent oil and gas exploration and production company. Our operations are mainly located in Texas, Oklahoma and New Mexico.

***Basis of presentation***

Our Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. Our significant accounting policies are discussed below. The accounts of Cimarex and its subsidiaries are presented in the accompanying Consolidated Financial Statements. All intercompany accounts and transactions were eliminated in consolidation.

***Segment Information***

We have determined that our business is comprised of only one segment because our gathering, processing and marketing activities are ancillary to our production operations and are not separately managed.

***Use of estimates***

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The more significant areas requiring the use of management's estimates and judgments relate to the estimation of proved oil and gas reserves, the use of these oil and gas reserves in calculating depletion, depreciation and amortization (DD&A), the use of the estimates of future net revenues in computing ceiling test limitations and estimates of future abandonment obligations used in recording asset retirement obligations and the assessment of goodwill.

The process of estimating quantities of oil and gas reserves is complex, requiring significant decisions in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that our reserve estimates represent the most accurate assessments possible, subjective decisions and available data for our various fields make these estimates generally less precise than other estimates included in financial statement disclosures.

Estimates and judgments are also required in determining allowance for doubtful accounts, impairments of undeveloped properties and other assets, purchase price allocation, valuation of deferred tax assets, fair value measurements and commitments and contingencies. We analyze our estimates, including those related to oil, gas and NGL revenues, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

***Cash and Cash Equivalents***

Cash and cash equivalents consist of cash in banks and investments readily convertible into cash, which have original maturities of three months or less. Cash equivalents are stated at cost, which approximates market value.

***Oil and Gas Well Equipment and Supplies***

The Financial Accounting Standards Board (FASB) issued new guidance (ASU 2015-11) to simplify the measurement of inventory effective for interim and annual periods beginning in 2017 with early adoption permitted. Under current guidance, inventory is carried at the lower of cost or market, where market can be replacement cost or a net realizable value. Under the new guidance, inventory is to be carried at the lower of cost or net realizable value, where net realizable value is a defined estimated selling price. We adopted this standard as of December 31, 2015.

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

***Oil and Gas Properties***

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

Companies that follow the full cost accounting method are required to make quarterly ceiling test calculations. This test ensures that total capitalized costs for oil and gas properties (net of accumulated DD&A and deferred income taxes) do not exceed the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related tax effects. We currently do not have any unproven properties that are being amortized. Estimated future net cash flows are determined by commodity prices and proved reserve quantities. Revenue calculations in the reserves are based on the unweighted average first-day-of-the-month prices for the prior 12 months. If net capitalized costs subject to amortization exceed this limit, the excess is charged to expense.

At December 31, 2015, 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 $965.3 million ($613.4 million, net of tax). We also recognized impairments in the first three quarters of 2015. Full year impairments totaled $3.7 billion ($2.4 billion, net of tax). These impairments resulted primarily from the 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 and stockholders' equity. Any recorded impairment of oil and gas properties is not reversible at a later date.

Depletion of proved oil and gas properties is computed on the units- of-production method, whereby capitalized costs, including future development costs and asset retirement obligations, are amortized over total estimated proved reserves. Changes in our estimate of proved reserve quantities, commodity prices and impairment of oil and gas properties will cause corresponding changes in depletion expense in periods subsequent to these changes.

The capitalized costs of unproved properties, including those in wells in progress, are excluded from the costs being amortized. We do not have major development projects that are excluded from costs being amortized. On a quarterly basis, we evaluate excluded costs for inclusion in the costs to be amortized resulting from the determination of proved reserves or impairments. To the extent that the evaluation indicates these properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

***Fixed assets, net***

Fixed assets consist primarily of gathering and plant facilities, vehicles, airplanes, office furniture, and computer equipment and software. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets, which range from 3 to 30 years.

***Goodwill***

Goodwill represents the excess of the purchase price of business combinations over the fair value of the net assets acquired and is tested for impairment at least annually. We have one reporting unit for which we first assess qualitative factors to determine whether it is more likely than not (with a greater than 50% threshold) that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. If goodwill is determined to be impaired then it is written down to a calculated fair value by charging the impairment to expense.

We evaluate our goodwill for impairment in the fourth quarter of each year or whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. Based upon our qualitative assessment at December 31, 2015, goodwill was not impaired. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors become less favorable.

***Revenue Recognition***

*Oil, Gas and NGL Sales*

Revenue is recorded from the sales of oil, gas and NGLs when the product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured. There is a ready market for our products and sales occur soon after production.

Under certain contracts, when NGLs are extracted from the gas stream, processors receive a portion of the sales value from both the residue gas and the NGLs as a processing fee and remit the contractual proceeds to us. Prior to 2014, revenue was recognized net of these processing fees for residue gas and NGLs sold under these contracts as allowed under EITF 00-10 Accounting for Shipping and Handling Fees and Costs. Increasing NGL production combined with the impact of recent changes to these contracts has resulted in processing costs becoming more significant. Accordingly, we have changed our policy to record these processing costs with operating costs as allowed under EITF 00-10. Beginning in 2014, our realized prices for sales under these contracts reflect the value of 100% of the residue gas and NGLs yielded by processing, rather than the value associated with the contractual proceeds we received. The related processing fees now are included in “transportation, processing and other operating” costs. The effect of this change in 2014 was that total revenue was $51.4 million higher with an offsetting increase in total transportation, processing and other operating costs. There was no impact on operating income. Financial statements for periods prior to 2014 have not been reclassified to reflect this change in accounting treatment as it was impracticable to do so.

*Marketing Sales*

We market and sell natural gas for working interest owners under short term sales and supply agreements and earn a fee for such services. Revenues are recognized as gas is delivered and are reflected net of gas purchases on the consolidated statements of operations and comprehensive income (loss).

*Gas Imbalances*

We use the sales method of accounting for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold. Gas reserves are adjusted to the extent there are sufficient quantities of natural gas to make up an imbalance. A liability is established in situations where there are insufficient proved reserves available to make-up an overproduced imbalance. Imbalances have not been significant in the periods presented.

***General and Administrative Expenses***

General and administrative expenses are reported net of amounts reimbursed by working interest owners of the oil and gas properties operated by Cimarex and net of amounts capitalized pursuant to the full cost method of accounting.

***Derivatives***

Our derivative contracts are recorded on the balance sheet at fair value. Our firm sales contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment. See Note 4 for additional information regarding our derivative instruments.

***Income Taxes***

In November 2015, the FASB issued a new standard (ASU 2015-17) regarding the balance sheet classification of deferred taxes for interim and annual periods beginning in 2017, with early adoption permitted on a prospective or retrospective basis. Under current guidance, entities that present a classified balance sheet must show both current and noncurrent amounts for deferred tax assets and liabilities. The new standard requires entities to classify all deferred tax assets and liabilities as noncurrent. We have elected to adopt this standard on a prospective basis as of December 31, 2015. Prior periods have not been retrospectively adjusted.

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in the financial statements and tax returns. We routinely assess the realizability of the deferred tax assets. If we conclude that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws.

We regularly assess and, if required, establish accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions where the company operates. See Note 9 for additional information regarding our income taxes.

***Contingencies***

A provision for contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes subjective judgment. In many cases, this judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. We closely monitor known and potential legal, environmental and other contingencies and periodically determine when we should record losses for these items based on information available to us. See Note 10 for additional information regarding our contingencies.

***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 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 current portions of the asset retirement obligations are recorded in “accrued liabilities, other” in the accompanying consolidated balance sheets and expenditures are classified as cash used in operating activities in the accompanying consolidated statements of cash flows. See Note 8 for additional information regarding our asset retirement obligations.

***Stock-based Compensation***

We recognize compensation related to all stock-based awards, including stock options, in the financial statements based on their estimated grant-date fair value. We grant various types of stock-based awards including stock options, restricted stock (including awards with service-based vesting and market condition-based vesting provisions) and restricted stock units. The fair value of stock option awards is determined using the Black-Scholes option pricing model. Service-based restricted stock and units are valued using the market price of our common stock on the grant date. The fair value of the market condition-based restricted stock is based on the grant-date market value of the award utilizing a statistical analysis. Compensation cost is recognized ratably over the applicable vesting period. To the extent compensation cost relates to employees directly involved in oil and gas acquisition, exploration and development activities, such amounts are capitalized to oil and gas properties. Amounts not capitalized to oil and gas properties are recognized as stock compensation expense. See Note 6 for additional information regarding our stock-based compensation.

***Earnings (loss) per Share***

We calculate earnings (loss) per share recognizing that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are "participating securities" and therefore should be included in computing earnings per share using the two-class earnings allocation method. The two-class method is an earnings allocation formula that determines earnings per share for each class of common stock and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. Our unvested share based payment awards, consisting of restricted stock and units, qualify as participating securities. See Note 7 for additional information regarding our earnings per share.

***Recently Issued Accounting Standards***

The FASB issued ASU 2015-03, Interest-Imputation of Interest, Simplifying the Presentation of Debt Issuance Costs in April 2015 and ASU 2015-15, Interest-Imputation of Interest-Presentation and Subsequent Measurement of Debt Issuance Costs associated with Line-of-Credit Arrangements in August 2015. These ASUs simplify the presentation of debt issuance costs by requiring such costs (except for those related to revolving credit facilities) to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability rather than as an asset. These ASUs are effective for annual and interim periods beginning in 2016. Early adoption is permitted. We adopted these ASUs at December 31, 2015. Accordingly, prior periods have been adjusted retrospectively to conform to this guidance (see Note 3).

In May 2014, the FASB issued 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. The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in this update supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. We do not intend to adopt the standard early. We have not determined which transition method we will use and are continuing to evaluate the potential impact of this guidance. At this time we do not expect that the adoption of this standard will have a material effect on our financial position or results of operation and related disclosures.

***Subsequent Events***

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

## 2. CAPITAL STOCK

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At December 31, 2015, there were no shares of preferred stock outstanding. See our Consolidated Statements of Stockholders' Equity for detailed capital stock activity.

In May 2015, we completed an underwritten public offering of 6,900,000 shares of common stock, which included 900,000 shares of common stock issued pursuant to an overallotment option to purchase additional shares granted to the underwriters. The stock was sold to the public at $109.00 per share, with a par value of $0.01, and we received net proceeds of approximately $730 million from the sale of these shares of common stock, after deducting underwriting fees.

*Dividends*

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| Dividend declared (in millions) | $ 59.3 | $ 55.7 | $ 48.4 |
| Dividend per share | $ 0.64 | $ 0.64 | $ 0.56 |

## 3. LONG-TERM DEBT

A summary of our debt is as follows:

| | December 31, 2015 | | December 31, 2014 | |
|---|---|---|---|---|
| **(in thousands)** | **Principal** | **Unamortized Debt Issuance Costs** | **Principal** | **Unamortized Debt Issuance Costs** |
| 5.875% Senior Notes, due May 1, 2022 | $ 750,000 | $ 6,978 | $ 750,000 | $ 8,343 |
| 4.375% Senior Notes, due June 1, 2024 | 750,000 | 7,402 | 750,000 | 8,481 |
| Total long-term debt | $ 1,500,000 | $ 14,380 | $ 1,500,000 | $ 16,824 |

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

In 2015, the FASB issued new guidance to simplify the presentation of debt issuance costs by requiring such costs (except for those related to revolving credit facilities) to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability (ASU 2015-03 and 2015-15). Historically, we have treated these costs as deferred assets and included them in Other assets, net in our balance sheet. We adopted the new guidance at December 31, 2015, and have applied it on a retrospective basis. The following table reflects the reclassification of $16.8 million of debt issuance costs from an asset to a direct deduction of the related debt liability for the balance sheet line items affected by the retrospective application of the change in accounting principle.

| | December 31, 2014 | |
|---|---|---|
| (in thousands) | After Adoption | As Previously Reported |
| Other assets, net | $ 41,691 | $ 58,515 |
| Long-term debt | $ 1,483,176 | $ 1,500,000 |

***Bank Debt***

In October 2015, we entered into a new senior unsecured revolving credit facility (Credit Facility) which matures October 16, 2020. The Credit Facility has aggregate commitments of $1.0 billion, with an 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 December 31, 2015, 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 new 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 December 31, 2015, we were in compliance with all of the financial and non-financial covenants.

ASU 2015-15 specifically exempts entities with revolving credit facilities from presenting associated debt issuance costs as a direct deduction from the carrying amount of the related liability. At December 31, 2015 and 2014, we had $5.7 million and $6.5 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. The costs are being amortized to interest expense ratably over the life of the Credit Facility.

***Senior Notes***

In June 2014, we issued $750 million of 4.375% senior notes due 2024 and received net proceeds of $740.9 million, after deducting offering discounts and costs. The net proceeds were used to pay outstanding bank debt and for general corporate purposes. The effective interest rate on the notes, including the debt issuance cost, is 4.50%.

In April 2012, we issued $750 million of 5.875% senior notes due 2022 and received net proceeds of $737.0 million, after deducting underwriting discounts and offering costs. We used a portion of the net proceeds to retire our 7.125% senior notes and the remaining proceeds were used to pay outstanding bank debt and for general corporate purposes. The effective interest rate on the notes, including the debt issuance cost, is 6.04%.

Each of our outstanding 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 December 31, 2015. Interest on each of the senior notes is payable semi-annually.

## 4. DERIVATIVE INSTRUMENTS/HEDGING

We periodically enter into derivative instruments to mitigate a portion of our potential exposure to a decline in commodity prices and the corresponding negative impact on cash flow available for reinvestment. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. 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.

The following tables summarize our derivative contracts as of December 31, 2015:

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Total |
|---|---|---|---|---|---|
| Oil Three-Way Collars: | | | | | |
| 2016: | | | | | |
| WTI (1) | | | | | |
| Volume (Bbls) | 273,000 | 273,000 | 276,000 | 276,000 | 1,098,000 |
| Wtd Avg Price - Lower Floor | $ 40.00 | $ 40.00 | $ 40.00 | $ 40.00 | $ 40.00 |
| Wtd Avg Price - Upper Floor | $ 50.00 | $ 50.00 | $ 50.00 | $ 50.00 | $ 50.00 |
| Wtd Avg Price - Ceiling | $ 60.00 | $ 60.00 | $ 60.00 | $ 60.00 | $ 60.00 |

(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) | 910,000 | 910,000 | 920,000 | 920,000 | 3,660,000 |
| Wtd Avg Price - Floor | $ 2.70 | $ 2.70 | $ 2.70 | $ 2.70 | $ 2.70 |
| Wtd Avg Price - Ceiling | $ 2.85 | $ 2.85 | $ 2.85 | $ 2.85 | $ 2.85 |
| Perm EP (1) | | | | | |
| Volume (MMBtu) | 1,820,000 | 1,210,000 | 920,000 | 920,000 | 4,870,000 |
| Wtd Avg Price - Floor | $ 2.75 | $ 2.75 | $ 2.75 | $ 2.75 | $ 2.75 |
| Wtd Avg Price - Ceiling | $ 3.12 | $ 3.09 | $ 3.06 | $ 3.06 | $ 3.09 |
| 2017: | | | | | |
| Perm EP (1) | | | | | |
| Volume (MMBtu) | 900,000 | 910,000 | — | — | 1,810,000 |
| Wtd Avg Price - Floor | $ 2.75 | $ 2.75 | $ — | $ — | $ 2.75 |
| Wtd Avg Price - Ceiling | $ 3.36 | $ 3.36 | $ — | $ — | $ 3.36 |

(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.

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.

Subsequent to December 31, 2015, we entered into the following gas hedges:

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Total |
|---|---|---|---|---|---|
| Gas Collars: | | | | | |
| 2016: | | | | | |
| PEPL | | | | | |
| Volume (MMBtu) | — | 1,820,000 | 1,840,000 | 1,840,000 | 5,500,000 |
| Wtd Avg Price - Floor | $ — | $ 2.13 | $ 2.13 | $ 2.13 | $ 2.13 |
| Wtd Avg Price - Ceiling | $ — | $ 2.70 | $ 2.70 | $ 2.70 | $ 2.70 |
| Perm EP | | | | | |
| Volume (MMBtu) | — | 1,820,000 | 1,840,000 | 1,840,000 | 5,500,000 |
| Wtd Avg Price - Floor | $ — | $ 2.25 | $ 2.25 | $ 2.25 | $ 2.25 |
| Wtd Avg Price - Ceiling | $ — | $ 2.77 | $ 2.77 | $ 2.77 | $ 2.77 |
| 2017: | | | | | |
| PEPL | | | | | |
| Volume (MMBtu) | 1,800,000 | 1,820,000 | — | — | 3,620,000 |
| Wtd Avg Price - Floor | $ 2.13 | $ 2.13 | $ — | $ — | $ 2.13 |
| Wtd Avg Price - Ceiling | $ 2.70 | $ 2.70 | $ — | $ — | $ 2.70 |
| Perm EP | | | | | |
| Volume (MMBtu) | 1,800,000 | 1,820,000 | — | — | 3,620,000 |
| Wtd Avg Price - Floor | $ 2.25 | $ 2.25 | $ — | $ — | $ 2.25 |
| Wtd Avg Price - Ceiling | $ 2.77 | $ 2.77 | $ — | $ — | $ 2.77 |

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 net (gains) and losses from settlements and changes in fair value of our derivative contracts, and the (gains) losses only from settlements during the periods shown below.

| (in thousands) | 2015 | 2014 | 2013 |
|---|---|---|---|
| (Gain) loss on derivative instruments, net | $ (11,246) | $ (3,762) | $ 209 |
| Settlement (gains) losses | $ — | $ (7,641) | $ 4,088 |

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.

The following table presents the amounts and classifications of our derivative assets and liabilities as of December 31, 2015, as well as the potential effect of netting arrangements on contracts with the same counterparty. We did not have any outstanding contracts as of December 31, 2014.

| 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.

## 5. 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.

The following table provides fair value measurement information for certain assets and liabilities as of December 31, 2015 and 2014.

| | December 31, 2015 | | December 31, 2014 | |
|---|---|---|---|---|
| **(in thousands)** | **Carrying Amount** | **Fair Value** | **Carrying Amount** | **Fair Value** |
| Financial Assets (Liabilities): | | | | |
| 5.875% Notes due 2022 | $ (743,022) | $ (723,750) | $ (741,657) | $ (776,250) |
| 4.375% Notes due 2024 | $ (742,598) | $ (683,318) | $ (741,519) | $ (720,000) |
| Derivative instruments — assets | $ 11,246 | $ 11,246 | $ — | $ — |

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

### *Debt (Level 1)*

The fair value for our 4.375% and 5.875% fixed rate notes was based on their last traded value before year end.

### *Derivative Instruments (Level 2)*

The fair value of our derivative instruments 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. Please see Note 4 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. Included in “accrued liabilities, other” at December 31, 2015 and 2014, respectively, are: 1) liabilities of approximately $23.1 million and $42.0 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts; 2) accrued payroll related general and administrative expenses of $21.5 million and $44.2 million; and 3) accrued operating expenses of $60.4 million and $67.5 million.

Our accounts receivable are primarily from either purchasers of our gas, oil and NGL production (customers) or from exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, because our customers and joint working interest owners may be similarly affected by changes in industry conditions.

We conduct credit analyses prior to making any sales to new customers or increasing credit for existing customers and may require parent company guarantees, letters of credit or prepayments when deemed necessary.

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 December 31, 2015, the allowance for doubtful accounts totaled $1.8 million. At December 31, 2014, the allowance for doubtful accounts was $1.5 million.

***Major Customers***

Our major customers during 2015 were Sunoco Logistics Partners L.P. (Sunoco) and Enterprise Products Partners L.P. (Enterprise). Sunoco and Enterprise accounted for 21% and 17%, respectively, of our consolidated revenues in 2015. During 2014, Enterprise and Sunoco each accounted for 19% of our consolidated revenues. Oneok Partners, L.P. accounted for 10% of our 2014 consolidated revenues.

Sunoco is a significant purchaser of our oil in Southeast New Mexico and Canadian County, Oklahoma. Enterprise is a significant oil purchaser in Oklahoma and West Texas. If either of these entities were to stop purchasing our production, we believe there are a number of other purchasers to whom we could sell our production with some delay. If both parties were to discontinue purchasing our product, we believe there would be challenges initially, but ample markets to handle the disruption.

## 6. STOCK-BASED and OTHER COMPENSATION

We have recognized non-cash stock-based compensation cost as shown below. Historical amounts may not be representative of future amounts as the value of future awards may vary from historical amounts.

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2015** | **2014** | **2013** |
| Restricted stock awards | | | |
| Performance stock awards | $ 18,991 | $ 12,141 | $ 11,105 |
| Service-based stock awards | 14,547 | 13,607 | 12,018 |
| | 33,538 | 25,748 | 23,123 |
| Stock option awards | 2,803 | 3,057 | 3,145 |
| | 36,341 | 28,805 | 26,268 |
| Less amounts capitalized to oil and gas properties | (16,782) | (13,804) | (11,989) |
| Compensation expense | $ 19,559 | $ 15,001 | $ 14,279 |

The increase in 2015 stock compensation is primarily related to performance awards granted in December 2014, a portion of which were amortized during 2015.

***Equity Incentive Plan***

Our 2014 Equity Incentive Plan (the 2014 Plan) was approved by stockholders in May 2014 and our previous plan was terminated at that time. Outstanding awards under the previous plan were not impacted. A total of 6.6 million shares of common stock may be issued under the 2014 Plan, including shares available from the previous plan. The 2014 Plan provides for grants of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, dividend equivalents and other stock-based awards.

*Restricted Stock*

The following table provides information about restricted stock awards granted during the last three years.

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2015 | | 2014 | | 2013 | |
| | Number of Shares | Weighted Average Grant-Date Fair Value | Number of Shares | Weighted Average Grant-Date Fair Value | Number of Shares | Weighted Average Grant-Date Fair Value |
| Performance stock awards | 263,939 | $ 87.12 | 316,441 | $ 83.22 | 298,000 | $ 77.75 |
| Service-based stock awards | 207,180 | $ 114.80 | 170,402 | $ 136.72 | 281,236 | $ 72.89 |
| Total restricted stock awards | 471,119 | $ 99.29 | 486,843 | $ 101.95 | 579,236 | $ 75.39 |

Performance awards were granted to eligible executives and are subject to market condition-based vesting determined by our stock price performance relative to a defined peer group's stock price performance. After three years of continued service, an executive will be entitled to vest in 50% to 100% of the award. In accordance with Internal Revenue Code Section 162(m), certain of the amounts awarded may not be deductible for tax purposes. Service-based stock awards granted to other eligible employees and non-employee directors have vesting schedules of three to five years.

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

The following table provides information on restricted stock activity during the year.

| | Service-based | | Performance (subject to market conditions) | |
|---|---|---|---|---|
| | Awards | Weighted Average Grant-Date Fair Value | Awards | Weighted Average Grant-Date Fair Value |
| Outstanding beginning of period | 1,036,417 | $ 82.69 | 877,211 | $ 69.38 |
| Vested | (181,665) | $ 72.16 | (284,675) | $ 47.29 |
| Granted | 207,180 | $ 114.80 | 263,939 | $ 87.12 |
| Canceled | (63,750) | $ 81.19 | (26,667) | $ 81.98 |
| Outstanding end of period | 998,182 | $ 91.37 | 829,808 | $ 82.99 |

The total fair value of restricted stock that vested was $52.2 million in 2015, $34.1 million in 2014, and $25.7 million in 2013.

Unrecognized compensation cost related to unvested restricted shares at December 31, 2015 was $85.8 million. We expect to recognize that cost over a weighted average period of 2.2 years.

*Restricted Units*

As of December 31, 2015 and 2014, we had 8,838 restricted units outstanding. These represent restricted units held by a non-employee director who has elected to defer payment of common stock represented by the units until termination of his service on the Board of Directors.

*Stock Options*

Options that have been granted under the 2014 plan and previous plans expire seven to ten years from the grant date and have service-based vesting schedules of three to five years. The exercise price for an option under the 2014 plan is the closing price of our common stock as reported by the New York Stock Exchange (NYSE) on the date of grant. The previous plans provided that all grants have an exercise price of the average of the high and low prices of our common stock as reported by the NYSE on the date of grant.

Compensation cost related to stock options is based on the grant-date fair value of the award, recognized ratably over the applicable vesting period. We estimate the fair value using the Black-Scholes option-pricing model. Expected volatilities are based on the historical volatility of our common stock. We also use historical data to estimate the probability of option exercise, expected years until exercise and potential forfeitures. We use U.S. Treasury bond rates in effect at the grant date for our risk-free interest rates.

The following summarizes the options granted and related information, and the assumptions used to determine the fair value of those options.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Options granted | 69,000 | 82,500 | 144,400 |
| Weighted average grant-date fair value | $ 37.56 | $ 41.69 | $ 21.64 |
| Weighted average exercise price | $ 115.28 | $ 139.02 | $ 72.25 |
| Total Fair Value (in thousands) | $ 2,592 | $ 3,439 | $ 3,125 |
| Expected years until exercise | 5.0 | 4.0 | 4.0 |
| Expected stock volatility | 36.6 % | 36.7 % | 38.6 % |
| Dividend yield | 0.6 % | 0.5 % | 0.8 % |
| Risk-free interest rate | 1.6 % | 1.8 % | 1.4 % |

Information about outstanding stock options is summarized below.

| | Options | Weighted Average Exercise Price | Weighted Average Remaining Term | Aggregate Intrinsic Value (in thousands) |
|---|---|---|---|---|
| Outstanding as of January 1, 2015 | 384,082 | $ 78.19 | | |
| Exercised | (141,517) | $ 59.73 | | |
| Granted | 69,000 | $ 115.28 | | |
| Canceled | (666) | $ 139.02 | | |
| Forfeited | (11,670) | $ 118.77 | | |
| Outstanding as of December 31, 2015 | 299,229 | $ 93.76 | 4.9 Years | $ 4,095 |
| Exercisable as of December 31, 2015 | 142,188 | $ 74.07 | 3.9 Years | $ 3,398 |

The following table provides information regarding options exercised and the grant-date fair value of options vested.

| (in thousands) | Years Ended December 31, 2015 | 2014 | 2013 |
|---|---|---|---|
| Number of options exercised | 141,517 | 211,258 | 276,069 |
| Cash received from option exercises | $ 8,451 | $ 11,898 | $ 14,494 |
| Tax benefit from option exercises included in paid-in-capital (1) | $ 4,442 | $ — | $ — |
| Intrinsic value of options exercised | $ 7,467 | $ 15,384 | $ 10,109 |
| Grant-date fair value of options vested | $ 2,734 | $ 4,419 | $ 2,521 |

(1) No tax benefit is recorded until the benefit reduces current taxes payable. However, in 2015 we recognized tax benefit on prior period option exercises.

The following summary reflects the status of non-vested stock options as of December 31, 2015 and changes during the year.

| | Options | | Weighted Average Grant-Date Fair Value | | Weighted Average Exercise Price |
|---|---|---|---|---|---|
| Non-vested as of January 1, 2015 | 205,156 | $ | 29.35 | $ | 94.76 |
| Vested | (105,445) | $ | 25.93 | $ | 80.49 |
| Granted | 69,000 | $ | 37.56 | $ | 115.28 |
| Forfeited | (11,670) | $ | 35.89 | $ | 118.77 |
| Non-vested as of December 31, 2015 | 157,041 | $ | 34.77 | $ | 111.58 |

As of December 31, 2015, there was $3.9 million of unrecognized compensation cost related to non-vested stock options. We expect to recognize that cost on a pro rata basis over a weighted average period of 1.8 years.

***Other Compensation***

We maintain and sponsor a contributory 401(k) plan for our employees. Annual matching costs related to the plan were $6.4 million for 2015. During 2014 and 2013, such costs were $11.0 million and $9.0 million, respectively.

## 7. EARNINGS (LOSS) PER SHARE

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

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| **(in thousands, except per share data)** | | **2015** | | **2014** | | **2013** |
| Basic: | | | | | | |
| Net income (loss) | $ | (2,408,948) | $ | 507,204 | $ | 564,689 |
| Participating securities' share in earnings (1) | | — | | (9,906) | | (11,091) |
| Net income (loss) applicable to common stockholders | $ | (2,408,948) | $ | 497,298 | $ | 553,598 |
| Diluted: | | | | | | |
| Net income (loss) | $ | (2,408,948) | $ | 507,204 | $ | 564,689 |
| Participating securities' share in earnings (1) | | — | | (9,891) | | (11,076) |
| Net income (loss) applicable to common stockholders | $ | (2,408,948) | $ | 497,313 | $ | 553,613 |
| Shares: | | | | | | |
| Basic shares outstanding | | 92,992 | | 85,679 | | 85,288 |
| Dilutive effect of stock options | | — | | 131 | | 121 |
| Fully diluted common stock | | 92,992 | | 85,810 | | 85,409 |
| Excluded (2) | | 2,136 | | 94 | | 251 |
| Earnings (loss) per share to common stockholders (3): | | | | | | |
| Basic | $ | (25.92) | $ | 5.79 | $ | 6.48 |
| Diluted | $ | (25.92) | $ | 5.78 | $ | 6.47 |

(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.

## 8. ASSET RETIREMENT OBLIGATIONS

The following table reflects the components of the change in the carrying amount of the asset retirement obligation for the years ended December 31, 2015 and 2014.

| (in thousands) | 2015 | 2014 |
|---|---|---|
| Asset retirement obligation at January 1, | $ 173,008 | $ 154,026 |
| Liabilities incurred | 4,114 | 13,015 |
| Liability settlements and disposals | (25,061) | (27,036) |
| Accretion expense | 7,682 | 7,583 |
| Revisions of estimated liabilities | 4,362 | 25,420 |
| Asset retirement obligation at December 31, | 164,105 | 173,008 |
| Less current obligation | 10,248 | 13,216 |
| Long-term asset retirement obligation | $ 153,857 | $ 159,792 |

The year-over-year decline in liabilities incurred resulted from lower drilling and acquisition activity in 2015. During 2015, the liability settlements and disposals included $13.3 million related to properties that were sold. During 2014, the liability settlements and disposals included $11.2 million related to properties that were sold. Also during 2014 we recognized revisions of estimated liabilities totaling $25.4 million, which were due to changes in abandonment cost and timing estimates.

## 9. INCOME TAXES

Federal income tax expense (benefit) for the years presented differs from the amounts that would be provided by applying the U.S. Federal income tax rate, primarily due to the effect of state income taxes, non-deductible expenses and revisions. The components of the provision for income taxes are as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013 |
| Current Taxes: | | | |
| Federal (benefit) | $ 14,417 | $ — | $ (381) |
| State (benefit) | 293 | 404 | (308) |
| | 14,710 | 404 | (689) |
| Deferred taxes: | | | |
| Federal (benefit) | (1,294,194) | 282,729 | 315,165 |
| State (benefit) | (93,952) | 15,564 | 14,535 |
| | (1,388,146) | 298,293 | 329,700 |
| | $ (1,373,436) | $ 298,697 | $ 329,011 |

Reconciliations of the income tax expense (benefit) calculated at the federal statutory rate of 35% to the total income tax expense are as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| (in thousands) | 2015 | 2014 | 2013 |
| Provision at statutory rate | $ (1,323,834) | $ 282,066 | $ 312,795 |
| Effect of state taxes | (60,634) | 15,826 | 14,226 |
| Revision of previous balances | 5,997 | — | — |
| Other permanent differences | 5,035 | 805 | 1,990 |
| Income tax expense (benefit) | $ (1,373,436) | $ 298,697 | $ 329,011 |

The components of Cimarex's net deferred tax liabilities are as follows:

| (in thousands) | December 31, 2015 | December 31, 2014 |
|---|---|---|
| Long-term: | | |
| Assets: | | |
| Stock compensation and other accrued amounts | $ 32,084 | $ 26,527 |
| Net operating loss carryforward, net of valuation allowance | 305,506 | 218,584 |
| Credit carryforward | 6,016 | 4,068 |
| | 343,606 | 249,179 |
| Liabilities: | | |
| Property, plant and equipment | (696,311) | (2,003,885) |
| Net, long-term deferred tax liability | (352,705) | (1,754,706) |
| Current: | | |
| Assets: | | |
| Other accrued amounts | — | 13,475 |
| | — | 13,475 |
| Net deferred tax liabilities | $ (352,705) | $ (1,741,231) |

At December 31, 2015, we had a U.S. net tax operating loss carryforward of approximately $907.5 million, which would expire in years 2031 through 2035. We believe that the carryforward will be utilized before it expires. We recorded an increase to the net operating loss carryforward at December 31, 2015, for certain state losses. The net increase in the state net operating loss valuation allowance during the year was $51.0 million. The total valuation allowance on state net operating losses at December 31, 2015, was $70.1 million because it is not more likely than not that these additional state net operating losses will be utilized before they expire. The amount of the 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.

At December 31, 2015 and 2014, we had no unrecognized tax benefits that would impact our effective rate and we have made no provisions for interest or penalties related to uncertain tax positions. The tax years 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.

## 10. COMMITMENTS AND CONTINGENCIES

### *Lease Commitments*

We have various commitments for office space and equipment under operating lease arrangements. Rent expense for the operating leases totaled $13.2 million in 2015. Rent expense was $14.3 million and $13.2 million for 2014 and 2013, respectively.

Shown below are future minimum cash payments required under these leases as of December 31, 2015.

| (in thousands) | Operating Leases |
|---|---|
| 2016 | $ 9,248 |
| 2017 | 9,625 |
| 2018 | 9,119 |
| 2019 | 9,196 |
| 2020 | 9,349 |
| Later years | 50,173 |
| Total future minimum lease payments | $ 96,710 |

***Other Commitments***

We have commitments of $201.7 million to finish drilling and completing wells in progress at December 31, 2015. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $21.6 million.

At December 31, 2015, we had firm sales contracts to deliver approximately 56 Bcf of natural gas over the next three years. If this gas is not delivered, our financial commitment would be approximately $116.7 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 $203.0 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 $12.4 million. Of this total, we have accrued a liability of $9.7 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 $36.3 million. We currently anticipate meeting these obligations.

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

***Litigation***

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

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

In 2008, we recorded litigation expense of $119.6 million for the *H.B. Krug, et al. v. Helmerich & Payne, Inc.* (H&P) lawsuit, and began accruing additional post-judgment interest and costs for this case.

Over the years, the lawsuit has been disputed until December 13, 2013 when the Oklahoma Supreme Court reversed the Tulsa County District Court's original judgment of $119.6 million and affirmed an alternative jury verdict for $3.65 million. It also remanded the case back to the trial court for consideration of potential prejudgment interest, attorney's fees and cost awards. Accordingly, on December 31, 2013 we reduced the previously recognized litigation expense, which included related interest and costs, and the associated long-term liability by $142.8 million.

On April 1, 2014, Cimarex paid the Plaintiffs $15.8 million in satisfaction of the $3.65 million damages award, the post-judgment interest award and the payment in lieu of bond, all of which are now final and not appealable. On June 24, 2014, the trial court ruled the Plaintiffs were not entitled to prejudgment interest but were entitled to attorney's fees and costs, the amount of which will be determined at a subsequent hearing. On November 3, 2015, the Oklahoma Supreme Court affirmed the trial court's denial of prejudgment interest. The only remaining issue is the amount of Plaintiffs' award of attorney's fees, which is subject to future trial and appellate court proceedings and, therefore, cannot be determined or estimated at this time.

## 11. RELATED PARTY TRANSACTIONS

Helmerich & Payne, Inc. (H&P) provides contract drilling services to Cimarex. Drilling costs of approximately $7.9 million were incurred by Cimarex related to such services for 2015. During 2014 and 2013, such costs were $18.4 million and $17.0 million, respectively. Hans Helmerich, a director of Cimarex, is Chairman of the Board of Directors of H&P.

Lisa Stewart joined our Board of Directors in October, 2015. Ms. Stewart is Chairman and Chief Investment Officer of Sheridan Production Partners, a privately-owned oil and gas operating company she founded in 2007. During 2015, Cimarex paid certain affiliates of Sheridan Production Partners oil and gas revenues of $224.2 thousand and received $81.5 thousand for joint interest billings. In addition, Cimarex paid the Sheridan affiliates joint interest billings of $10.4 thousand and received $4.1 thousand of oil and gas revenues.

Jerry Box, a director of Cimarex whose term expired May 2015, was the non-executive Chairman of the Board of Newpark through May 2014. Certain subsidiaries of Newpark Resources, Inc. provided various drilling services to Cimarex. Costs of such services were $0.6 million through May 2014. During 2013, such costs were $3.5 million.

## 12. PROPERTY SALES AND ACQUISITIONS

The following sales and acquisitions were made in the ordinary course of business. All amounts are net of customary purchase price adjustments.

There were no significant sales and acquisitions in 2015. We sold interests in various non-core oil and gas properties for $446.1 million during 2014. Most of the proceeds were related to sales of producing gas wells in southwestern Kansas and undeveloped acreage in Reagan County, Texas. During 2014, we made property acquisitions totaling $249.7 million, most of which were in our Cana-Woodford shale play in Western Oklahoma.

In 2013, we sold interests in non-core oil and gas assets for $61.5 million. During the second quarter of 2013, we also sold a 50% interest in our Culberson County, Texas Triple Crown gas gathering and processing system for approximately $31 million. Total property acquisitions during 2013 were $37.1 million, mostly for undeveloped acreage in Reeves County, Texas.

## 13. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2015** | **2014** | **2013** |
| Cash paid during the period for: | | | |
| Interest expense (including capitalized amounts) | $ 80,785 | $ 66,167 | $ 50,754 |
| Interest capitalized | $ 28,819 | $ 32,623 | $ 29,098 |
| Income taxes | $ 558 | $ 354 | $ 205 |
| Cash received for income taxes | $ 1,503 | $ 460 | $ 966 |

## SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

***Oil and Gas Reserve Information***—Proved reserve quantities are based on estimates prepared by Cimarex in accordance with guidelines established by the Securities and Exchange Commission (SEC).

Reserve definitions comply with definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC. All of our reserve estimates are maintained by our internal Corporate Reservoir Engineering group, which is comprised of reservoir engineers and engineering technicians. The objectives and management of this group are separate from and independent of the exploration and production functions of our company. The technical employee primarily responsible for overseeing the reserve estimation process is our company's Vice President of Corporate Engineering. This individual graduated from the Colorado School of Mines with a Bachelor of Science degree in Engineering and has more than 21 years of practical experience in reserve evaluation. He has been directly involved in the annual reserve reporting process of Cimarex since 2002 and has served in his current role for the past eleven years.

DeGolyer and MacNaughton, an independent petroleum engineering consulting firm, reviewed greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2015. The individual primarily responsible for overseeing the review is a Senior Vice President with DeGolyer and MacNaughton and a Registered Professional Engineer in the State of Texas with over 41 years of experience in oil and gas reservoir studies and evaluations.

Proved reserves are those quantities of oil, NGL and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and the timing of development expenditures. The estimation of our proved reserves employs one or more of the following: production trend extrapolation, analogy, volumetric assessment and material balance analysis. Techniques including review of production and pressure histories, analysis of electric logs and fluid tests, and interpretations of geologic and geophysical data also are involved in this estimation process.

The following table summarizes the trailing 12-month index prices used in the reserve estimates for 2015, 2014, and 2013. These prices are prior to adjustments for fixed and determinable amounts under provisions in existing contracts, location, grade and quality.

| | December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| Gas price per Mcf | $ 2.59 | $ 4.35 | $ 3.67 |
| Oil price per Bbl | $ 50.28 | $ 94.99 | $ 96.78 |
| NGL price per Bbl | $ 14.41 | $ 30.89 | $ 32.31 |

The following reserve data represents estimates only and should not be construed as being exact.

| | Gas (MMcf) | Oil (MBbl) | NGL (MBbl) | Total Gas Equivalents (MMcfe) |
|---|---|---|---|---|
| **Total proved reserves:** | | | | |
| **December 31, 2012** | 1,251,863 | 77,921 | 89,909 | 2,258,844 |
| Revisions of previous estimates | (101,235) | (2,942) | (16,197) | (216,068) |
| Extensions and discoveries | 280,619 | 48,010 | 26,431 | 727,267 |
| Purchases of reserves | 263 | 27 | 9 | 479 |
| Production | (125,248) | (13,380) | (7,876) | (252,787) |
| Sales of properties | (12,762) | (1,103) | (232) | (20,771) |
| **December 31, 2013** | 1,293,500 | 108,533 | 92,044 | 2,496,964 |
| Revisions of previous estimates | 85,533 | (1,039) | 4,262 | 104,873 |
| Extensions and discoveries | 420,442 | 29,155 | 36,424 | 813,911 |
| Purchases of reserves | 88,227 | 1,383 | 6,186 | 133,641 |
| Production | (155,128) | (15,639) | (11,343) | (317,022) |
| Sales of properties | (65,841) | (3,401) | (2,300) | (100,044) |
| **December 31, 2014** | 1,666,733 | 118,992 | 125,273 | 3,132,323 |
| Revisions of previous estimates | (154,390) | (14,633) | (5,668) | (276,192) |
| Extensions and discoveries | 183,084 | 22,859 | 18,079 | 428,714 |
| Purchases of reserves | 15 | 1 | 1 | 25 |
| Production | (168,987) | (18,663) | (13,063) | (359,343) |
| Sales of properties | (9,503) | (758) | (345) | (16,120) |
| **December 31, 2015** | 1,516,952 | 107,798 | 124,277 | 2,909,407 |
| **Proved developed reserves:** | | | | |
| December 31, 2012 | 985,352 | 73,524 | 63,757 | 1,809,037 |
| December 31, 2013 | 1,060,704 | 86,665 | 69,089 | 1,995,233 |
| December 31, 2014 | 1,263,957 | 100,050 | 89,630 | 2,402,033 |
| December 31, 2015 | 1,129,490 | 89,189 | 87,549 | 2,189,920 |
| **Proved undeveloped reserves:** | | | | |
| December 31, 2012 | 266,511 | 4,397 | 26,152 | 449,807 |
| December 31, 2013 | 232,796 | 21,868 | 22,955 | 501,731 |
| December 31, 2014 | 402,776 | 18,942 | 35,643 | 730,290 |
| December 31, 2015 | 387,462 | 18,609 | 36,728 | 719,487 |

Year-end 2015 proved reserves declined by 7% to 2.9 Tcfe, compared to 3.1 Tcfe at year-end 2014. Proved natural gas reserves were 1.5 Tcf, oil contributed 0.65 Tcfe and NGLs accounted for 0.75 Tcfe. Our Mid-Continent's reserves accounted for 63% of total proved reserves with the remainder in the Permian Basin.

During 2015, we added 429 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin. In the Mid-Continent, we added 177 Bcfe. In the Permian Basin, we added 251 Bcfe. In addition, we had net positive performance revisions of 142 Bcfe. The performance revisions included 47 Bcfe for better than expected performance of PUD reserves converted to proved developed reserves during the year and positive adjustments of 95 Bcfe to previously booked PUD reserves.

During 2015, we had net negative reserve revisions of 276 Bcfe. The significant decrease in commodity prices seen in 2015 resulted in negative revisions of 399 Bcfe due to prices. In addition, 19 Bcfe of negative revisions was due to increases in operating expenses, which shortened the economic lives of properties. These decreases were partially offset by the 142 Bcfe of net positive performance revisions discussed above.

During 2014, we added 813.9 Bcfe of proved reserves through extensions and discoveries, primarily in the Mid-Continent and Permian Basin. In the Mid-Continent, we added 80.4 Bcfe from wells drilled. We also added 496.6 Bcfe of PUD reserves in our Cana-Woodford shale area. In the Permian Basin, development drilling added 234.3 Bcfe.

During 2014, we had net positive reserve revisions of 105 Bcfe. This included positive revisions of 16 Bcfe due to prices offset by negative revisions of 25 Bcfe due to increases in operating expenses, which shortened the economic lives of properties. Performance revisions were a net positive of roughly 114 Bcfe. This net increase was due to better than expected performance of PUD reserves converted to proved developed reserves during the year (125 Bcfe) and positive adjustments to previously booked PUD reserves (10 Bcfe) offset by 21 Bcfe of net negative revisions primarily attributed to Cana-Woodford wells impacted by infill drilling.

In 2013, we added 727.3 Bcfe of proved reserves through extensions and discoveries, primarily in the Permian Basin and Cana-Woodford area. We added 489.4 Bcfe in the Permian Basin (288.2 Bcfe development drilling and 201.2 Bcfe in proved undeveloped reserves). Of this amount, 52% consisted of oil. In our western Oklahoma Cana-Woodford shale area, we added 44.9 Bcfe from wells drilled and 179.9 Bcfe of PUD reserves.

Approximately 208 Bcfe of the 216 Bcfe of net negative revisions in 2013 relates to performance of certain wells drilled in our Cana-Woodford shale development project. Negative revisions resulted from poorer than expected production performance of PUD reserves converted to proved developed reserves during the year (72 Bcfe); wells adversely impacted by infill drilling and/or exhibiting poorer than expected performance (60 Bcfe); the removal of PUD locations due to altered future drilling plans (40 Bcfe); and adjustments to previously booked PUD reserves based on actual results observed in 2013 (36 Bcfe). The remainder of net negative revisions relates to offsetting increases and decreases primarily associated with higher commodity prices and increased operating expenses.

At December 31, 2015, we had PUD reserves of 719 Bcfe, down 11 Bcfe from 730 Bcfe of PUDs at December 31, 2014. Changes in our PUD reserves are summarized in the table below (in Bcfe).

| | |
|---|---|
| PUD reserves at December 31, 2014 | 730 |
| Converted to developed | (173) |
| Additions | 116 |
| Net revisions | 46 |
| PUD reserves at December 31, 2015 | 719 |

During 2015, we invested $246.5 million to develop and convert 24% of our 2014 PUD reserves to proved developed reserves. A portion of the development costs were on PUD locations that are expected to be converted to developed in subsequent periods. During 2014, we invested $503.5 million for conversion of PUD reserves to proved developed reserves, converting 56% of our 2013 PUD reserves.

All 116 Bcfe of PUD reserve additions occurred in our western Oklahoma, Cana-Woodford shale play. Roughly 90% of our PUD reserves are associated with this area. The remainder of our PUD reserves is found in the Permian Basin. We have no PUD reserves that have remained undeveloped for five years or more after initial disclosure. We have no PUD reserves whose scheduled delay to initiation of development is beyond five years of initial booking.

***Costs Incurred***—The following table sets forth the capitalized costs incurred in our oil and gas production, exploration, and development activities.

| **(in thousands)** | **Years Ended December 31, 2015** | **2014** | **2013** |
|---|---|---|---|
| Costs incurred during the year: | | | |
| Acquisition of properties | | | |
| Proved | $ 30 | $ 138,508 | $ 682 |
| Unproved | 41,233 | 277,099 | 195,121 |
| Exploration | 6,902 | 50,271 | 52,672 |
| Development | 823,830 | 1,664,877 | 1,354,098 |
| Oil and gas expenditures | 871,995 | 2,130,755 | 1,602,573 |
| Property sales | (41,276) | (446,107) | (61,503) |
| | 830,719 | 1,684,648 | 1,541,070 |
| Asset retirement obligation, net | (4,818) | 27,243 | 4,426 |
| | $ 825,901 | $ 1,711,891 | $ 1,545,496 |

***Aggregate Capitalized Costs***—The table below reflects the aggregate capitalized costs relating to our oil and gas producing activities at December 31, 2015.

| **(in thousands)** | |
|---|---|
| Proved properties | $ 15,546,948 |
| Unproved properties and properties under development, not being amortized | 440,166 |
| | 15,987,114 |
| Less-accumulated depreciation, depletion and amortization (*) | (12,710,968) |
| Net oil and gas properties | $ 3,276,146 |

(*) Includes $3.7 billion of ceiling test limitation impairment incurred in 2015.

***Costs Not Being Amortized***—The following table summarizes oil and gas property costs not being amortized at December 31, 2015, by year that the costs were incurred.

| **(in thousands)** | |
|---|---|
| 2015 | $ 119,972 |
| 2014 | 198,693 |
| 2013 | 51,502 |
| 2012 and prior | 69,999 |
| | $ 440,166 |

Of the costs not being amortized, $83.0 million (19%) relates to unevaluated wells in progress and $51.9 million (12%) is capitalized interest. The remaining $305.3 million is for land and seismic expenditures, most of which were for costs invested in our Mid-Continent region ($181.5 million) and our Permian Basin region ($87.2 million). On a quarterly basis, all of these costs are evaluated for inclusion in the costs to be amortized resulting from the determination of proved reserves, impairments or reductions in value. We expect to include these costs in the amortization computation as we continue with our exploration and development plans.

***Oil and Gas Operations***—The following table contains direct revenue and cost information relating to our oil and gas exploration and production activities for the periods indicated. We have no long-term supply or purchase agreements with governments or authorities in which we act as producer. Income tax expense related to our oil and gas operations are computed using the effective tax rate for the period.

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in thousands, except per Mcfe)** | **2015** | **2014** | **2013** |
| Oil, gas and NGL revenues from production | $ 1,417,538 | $ 2,372,829 | $ 1,952,505 |
| Less operating costs and income taxes: | | | |
| Impairment of oil and gas properties | 3,716,883 | — | — |
| Depletion | 736,583 | 773,817 | 584,628 |
| Asset retirement obligation | 9,121 | 10,082 | 7,989 |
| Production | 299,374 | 342,304 | 286,742 |
| Transportation, processing and other operating | 183,134 | 215,246 | 109,818 |
| Taxes other than income | 84,764 | 128,793 | 112,732 |
| Income tax expense (benefit) | (1,311,634) | 334,499 | 313,104 |
| | 3,718,225 | 1,804,741 | 1,415,013 |
| Results of operations from oil and gas producing activities | $ (2,300,687) | $ 568,088 | $ 537,492 |
| Depletion rate per Mcfe | $ 2.05 | $ 2.44 | $ 2.31 |

***Standardized Measure of Future Net Cash Flows***—The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" (Standardized Measure) is calculated in accordance with guidance provided by the FASB. The Standardized Measure does not purport, nor should it be interpreted, to present the fair value of a company's proved oil and gas reserves. Fair value would require, among other things, consideration of expected future economic and operating conditions, varying price and cost assumptions, and risks inherent in reserve estimates.

Under the Standardized Measure, future cash inflows are based upon the forecasted future production of year-end proved reserves. Future cash inflows are then reduced by estimated future production and development costs to determine net pre-tax cash flow. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash flow over our tax basis in the associated oil and gas properties. Tax credits and permanent differences are also considered in the future income tax calculation. Future net cash flow after income taxes is discounted using a 10% annual discount rate to arrive at the Standardized Measure.

The following summary sets forth our Standardized Measure.

| | December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2015** | **2014** | **2013** |
| Cash inflows | $ 8,839,485 | $ 19,892,471 | $ 16,565,980 |
| Production costs | (3,521,881) | (5,777,710) | (5,000,004) |
| Development costs | (1,058,020) | (1,453,860) | (1,113,743) |
| Income tax expense | (728,029) | (3,768,780) | (3,099,304) |
| Net cash flow | 3,531,555 | 8,892,121 | 7,352,929 |
| 10% annual discount rate | (1,597,424) | (4,539,276) | (3,754,035) |
| Standardized measure of discounted future net cash flow | $ 1,934,131 | $ 4,352,845 | $ 3,598,894 |

The estimates of cash flows and reserve quantities shown above are based upon the unweighted average 12-month-first-day-of-the-month benchmark prices. See table above under ***Oil and Gas Reserve Information*** for prices used in determining the Standardized Measure. If future gas sales are covered by contracts at specified prices, the contract prices would be used. Prices are market driven and will fluctuate due to supply and demand factors, seasonality and geopolitical and economic factors.

The following are the principal sources of change in the Standardized Measure.

| (in thousands) | December 31, 2015 | 2014 | 2013 |
|---|---|---|---|
| Standardized Measure, beginning of period | $ 4,352,845 | $ 3,598,894 | $ 2,908,701 |
| Sales, net of production costs | (850,267) | (1,686,486) | (1,443,213) |
| Net change in sales prices, net of production costs | (4,262,261) | (176,200) | 362,356 |
| Extensions and discoveries, net of future production and development costs | 573,373 | 1,633,285 | 1,901,786 |
| Changes in future development costs | 280,163 | 23,025 | 121,347 |
| Previously estimated development costs incurred during the period | 214,749 | 442,780 | 253,047 |
| Revision of quantity estimates | (240,063) | 230,673 | (436,856) |
| Accretion of discount | 638,948 | 520,058 | 416,594 |
| Change in income taxes | 1,691,721 | (434,949) | (344,447) |
| Purchases of reserves in place | 20 | 228,539 | 1,552 |
| Sales of properties | (26,225) | (185,326) | (38,080) |
| Change in production rates and other | (438,872) | 158,552 | (103,893) |
| Standardized Measure, end of period | $ 1,934,131 | $ 4,352,845 | $ 3,598,894 |

**SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED)**

| 2015 | Quarter First | Second | Third | Fourth |
|---|---|---|---|---|
| (in thousands, except for per share data) | | | | |
| Revenues | $ 361,002 | $ 424,283 | $ 356,055 | $ 311,279 |
| Expenses, net (1) | 775,943 | 1,024,498 | 1,119,339 | 941,787 |
| Net income (loss) | $ (414,941) | $ (600,215) | $ (763,284) | $ (630,508) |
| Earnings (loss) per share to common stockholders: | | | | |
| Basic: | | | | |
| Distributed | $ 0.16 | $ 0.16 | $ 0.16 | $ 0.16 |
| Undistributed | (5.00) | (6.63) | (8.37) | (6.94) |
| | $ (4.84) | $ (6.47) | $ (8.21) | $ (6.78) |
| Diluted: | | | | |
| Distributed | $ 0.16 | $ 0.16 | $ 0.16 | $ 0.16 |
| Undistributed | (5.00) | (6.63) | (8.37) | (6.94) |
| | $ (4.84) | $ (6.47) | $ (8.21) | $ (6.78) |

(1) The 2015 quarterly expenses, net include non-cash impairments to our oil and gas properties of $603.6 million (or $4.47 per diluted share), $967.3 million (or $6.62 per diluted share), $1.2 billion (or $8.07 per diluted share) and $965.3 million (or $6.60 per diluted share) for the first quarter through the fourth quarter of 2015, respectively, as discussed in Note 1 to the Consolidated Financial Statements under ***Oil and Gas Properties***.

| 2014 | Quarter First | Second | Third | Fourth |
|---|---|---|---|---|
| **(in thousands, except for per share data)** | | | | |
| Revenues | $ 599,216 | $ 636,669 | $ 649,740 | $ 538,551 |
| Expenses, net | 460,759 | 488,029 | 505,425 | 462,759 |
| Net income | $ 138,457 | $ 148,640 | $ 144,315 | $ 75,792 |
| Earnings per share to common stockholders: | | | | |
| Basic: | | | | |
| Distributed | $ 0.16 | $ 0.16 | $ 0.16 | $ 0.16 |
| Undistributed | 1.43 | 1.55 | 1.49 | 0.71 |
| | $ 1.59 | $ 1.71 | $ 1.65 | $ 0.87 |
| Diluted: | | | | |
| Distributed | $ 0.16 | $ 0.16 | $ 0.16 | $ 0.16 |
| Undistributed | 1.43 | 1.54 | 1.49 | 0.70 |
| | $ 1.59 | $ 1.70 | $ 1.65 | $ 0.86 |

The sum of the individual quarterly net income per common share amounts may not agree with year-to-date net income per common share because each quarter's computation is based on the number of shares outstanding at the end of the applicable quarter using the two-class method.

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

### *EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES*

Cimarex's management, under the supervision and with the participation of the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), have evaluated the effectiveness of Cimarex's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of December 31, 2015. 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 our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

### *MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING*

Cimarex's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). The company's internal control over financial reporting is a process designed by, or under the supervision of, the CEO and CFO to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles.

Because of the inherent limitations of internal control over financial reporting, misstatements may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2015, management assessed the effectiveness of the company's internal control over financial reporting based on the criteria established in "Internal Control-Integrated Framework (2013)," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management concluded that the company's internal control over financial reporting was effective as of December 31, 2015.

Our independent registered public accounting firm has audited, and reported on, the effectiveness of our internal controls over financial reporting as of December 31, 2015, which follows this report.

**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Stockholders

Cimarex Energy Co.:

We have audited Cimarex Energy Co. and subsidiaries internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Cimarex Energy Co. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Cimarex Energy Co. and subsidiaries' internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Cimarex Energy Co. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Cimarex Energy Co. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations and comprehensive income (loss), stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2015, and our report dated February 23, 2016 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Denver, Colorado
February 23, 2016

## ITEM 9B. OTHER INFORMATION

None.

## PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning the directors of Cimarex required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2016 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2015. The executive officers of Cimarex as of February 23, 2016 were:

| Name | Age | Office |
|---|---|---|
| Thomas E. Jorden | 58 | Chairman of the Board, Chief Executive Officer and President |
| Joseph R. Albi | 57 | Executive Vice President – Operations, Chief Operating Officer |
| Stephen P. Bell | 61 | Executive Vice President – Business Development |
| G. Mark Burford | 48 | Vice President and Chief Financial Officer |
| Francis B. Barron | 53 | Senior Vice President – General Counsel |
| John A. Lambuth | 53 | Senior Vice President – Exploration |
| Gary R. Abbott | 43 | Vice President – Corporate Engineering |
| Richard S. Dinkins | 71 | Vice President – Human Resources |
| Krista L. Johnson | 45 | Vice President –Governmental and External Affairs |
| James H. Shonsey | 64 | Vice President – Controller, Chief Accounting Officer |

There are no family relationships by blood, marriage, or adoption among any of the above executive officers. All executive officers are elected annually by the board of directors to serve for one year or until a successor is elected and qualified. There is no arrangement or understanding between any of the officers and any other person pursuant to which he was selected as an executive officer.

***THOMAS E. JORDEN*** was elected chairman of the board effective August 14, 2012 after being named president and chief executive officer effective September 30, 2011. Since December 8, 2003, Mr. Jorden served as executive vice president of exploration and had served in a similar capacity since September 30, 2002. Prior to September 2002, Mr. Jorden was with Key Production Company, Inc., where he served as vice president of exploration (October 1999 to September 2002) and chief geophysicist (November 1993 to September 1999). Prior to joining Key, Mr. Jorden was with Union Pacific Resources.

***JOSEPH R. ALBI*** was named executive vice president and chief operating officer effective September 30, 2011. Mr. Albi served as executive vice president of operations since March 1, 2005. Since December 8, 2003, Mr. Albi served as senior vice president of corporate engineering. From September 30, 2002 to December 8, 2003, he served as vice president of engineering. From October 1999 to September, 2002, Mr. Albi was with Key Production Company, Inc. where he served as vice president of engineering and manager of engineering.

***STEPHEN P. BELL*** was named executive vice president, business development effective September 13, 2012. Since September, 2002, Mr. Bell served as senior vice president of business development and land. Prior to its merger with Cimarex, Mr. Bell was with Key Production Company, Inc. since February 1994. In September 1999, he was appointed senior vice president, business development and land. From February 1994 to September 1999, he served as vice president, land.

***G. MARK BURFORD*** was named vice president and chief financial officer in September 2015. He was appointed vice president, capital markets and planning in December 2010. Mr. Burford joined Cimarex in April 2005 as director of capital markets. Prior to joining Cimarex he was director of investor relations for Whiting Petroleum and Tom Brown, Inc. His experience also includes equity research with Petrie Parkman & Co., an investment banking firm, and public accounting.

***FRANCIS B. BARRON*** joined Cimarex in July 2013 as senior vice president, general counsel. Mr. Barron served as executive vice president, general counsel of Bill Barrett Corporation, a publicly traded, Denver-based oil and gas exploration and development company, from February 2009 until July 2013 and as secretary from March 2004 until

July 2013. He served as their senior vice president, general counsel from March 2004 until February 2009 and as chief financial officer from November 2006 until March 2007. Previously, Mr. Barron was a partner at the Denver, Colorado office of the law firm of Patton Boggs LLP as well as a partner at Bearman Talesnick & Clowdus Professional Corporation. Mr. Barron's practice included corporate, securities and business law for publicly traded oil and gas companies.

***JOHN LAMBUTH*** was named senior vice president of exploration in December 2015. Prior to his promotion, he served as the Company's vice president of exploration since September 2012 and chief geophysicist, a position he held since joining Cimarex in 2004. Mr. Lambuth began his career in 1985 with Shell Oil Co., where he held various positions in exploration and in research and development. Immediately prior to joining Cimarex, he spent three years as onshore exploration manager of El Paso Energy Company. Mr. Lambuth holds a Bachelors' Degree in Geophysical Engineering from the Colorado School of Mines.

***GARY R. ABBOTT*** was elected vice president of corporate engineering March 1, 2005. Since January 2002, Mr. Abbott served as manager, corporate reservoir engineering. From April 1999 to January 2002, Mr. Abbott was a reservoir engineer with Key Production Company, Inc.

***RICHARD S. DINKINS*** was named vice president of human resources on December 8, 2003. Mr. Dinkins joined Key Production Company, Inc. in March 2002 as its director of human resources and continued in that position with Cimarex commencing in September 2002. Prior to joining Key, Mr. Dinkins was with Sprint and before that, served as vice president of human resources for Terra Resources, Inc. and Pacific Enterprises Oil Company.

***KRISTA L. JOHNSON*** joined Cimarex as vice president of governmental and external affairs in November 2014. Previously she served at Shell Oil Company since 2006, her last role as vice president, international organizations. Prior to joining Shell, she spent eight years with Western Gas Resources, most recently as director of government and media relations. Her experience also includes private practice in oil and gas law, client based energy advocacy in Washington, work in the Federal Relations Department of the American Petroleum Institute, and in the office of former U.S. Senator Conrad Burns. Ms. Johnson is a graduate of the University of Puget Sound and received her J.D. from The Georgetown University Law Center.

***JAMES H. SHONSEY*** was named vice president in April 2006. Mr. Shonsey was elected chief accounting officer and controller on May 28, 2003. From 2001 to May 2003, Mr. Shonsey was chief financial officer of The Meridian Resource Corporation; and from 1997 to 2001, he served as the chief financial officer of Westport Resources Corporation.

## ITEM 11. EXECUTIVE COMPENSATION

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2016 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2015.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2016 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2015.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2016 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2015.

## ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required under this item is incorporated by reference from the Cimarex Energy Co. definitive Proxy Statement for the May 12, 2016 Annual Meeting of Shareholders. The Proxy Statement will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2015.

## PART IV

## ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES



Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith; all exhibits not so designated are incorporated by reference to a prior SEC filing as indicated.

| Exhibit | Title |
|---|---|
| 3.1 | Amended and Restated Certificate of Incorporation of Cimarex Energy Co. (filed as Exhibit 3.1 to Registrant's Form 8-K (Commission File no. 001-31446) dated June 7, 2005 and incorporated herein by reference). |
| 3.2 | Amended and Restated By-laws of Cimarex Energy Co. dated December 11, 2013 (filed on December 16, 2013 (Commission File No. 001-31446) and incorporated herein by reference). |
| 3.3 | Amended and Restated By-laws of Cimarex Energy Co. dated November 11, 2015 (filed as Exhibits 3.1 and 3.2 to the Current Report on Form 8-K filed on November 12, 2015 (Commission File No. 001-31446) and incorporated herein by reference). |
| 4.1 | Specimen Certificate of Cimarex Energy Co. common stock (filed as Exhibit 4.3 to Registration Statement on Form S-3 filed September 17, 2012 (Registration No. 333-183939) and incorporated herein by reference). |
| 4.2 | Debt Securities Indenture dated as of April 5, 2012, by and among Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference. |
| 4.3 | First Supplemental Indenture dated as of April 5, 2012, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference. |
| 4.4 | Form of 5.875% Senior Notes due 2022 included in Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed on April 5, 2012 and incorporated herein by reference. |
| 4.5 | Indenture dated as of June 4, 2014, by and between Cimarex Energy Co. and U.S. Bank National Association, as trustee included as Exhibit 4.1 to Registrant's Current Report on Form 8-K filed on June 4, 2014 and incorporated herein by reference. |
| 4.6 | First Supplemental Indenture dated as of June 4, 2014, by and among Cimarex Energy Co., the Subsidiary Guarantors party thereto and U.S. Bank National Association, as trustee included as Exhibit 4.2 to Registrant's Current Report on Form 8-K filed on June 4, 2014 and incorporated herein by reference. |

4.7 Form of 4.375% Senior Notes due 2024 included in Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on June 4, 2014 and incorporated herein by reference.

4.8 Form of Indenture by and among Cimarex Energy Co. and U.S. Bank National Association, as trustee (filed as Exhibit 4.7 to Registration Statement on Form S-3 filed September 21, 2015 (Registration No. 333-183939) and incorporated herein by reference).

10.1 Credit Agreement dated as of July 14, 2011, among Cimarex, the Administrative Agent, the Co-Syndication Agents, the Co-Documentation Agents and the Lenders filed on July 18, 2011 as Exhibit 10.l to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

10.2 First Amendment to Credit Agreement dated as of July 19, 2012, among Cimarex, the Guarantors, the Administrative Agent, and the Lenders filed on May 5, 2014 as Exhibit 10.1 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

10.3 Second Amendment to Credit Agreement dated as of May 1, 2014, among Cimarex, the Guarantors, the Administrative Agent, and the Lenders filed on May 5, 2014 as Exhibit 10.2 to the Registrant's Current Report on Form 8-K and incorporated herein by reference.

10.4 Employment Agreement, dated September 7, 1999, by and between Paul Korus and Key Production Company, Inc. (filed as Exhibit 10.6 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.5 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Paul Korus (filed as Exhibit 10.9 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.6 Employment Agreement, dated October 25, 1993, by and between Thomas E. Jorden and Key Production Company, Inc. (filed as Exhibit 10.7 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.7 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Thomas E. Jorden (filed as Exhibit 10.11 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.8 Employment Agreement, dated February 2, 1994, by and between Stephen P. Bell and Key Production Company, Inc. (filed as Exhibit 10.8 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.9 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Stephen P. Bell (filed as Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.10 Employment Agreement, dated March 11, 1994, by and between Joseph R. Albi and Key Production Company, Inc. (filed as Exhibit 10.9 to the Registration Statement on Form S-4 dated May 9, 2002 (Registration No. 333-87948) and incorporated herein by reference).

10.11 Amendment to Employment Agreement effective January 1, 2009 between Cimarex Energy Co. and Joseph R. Albi (filed as Exhibit 10.15 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.12 Amended and Restated 2002 Stock Incentive Plan of Cimarex Energy Co. effective January 1, 2009 (filed as Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001- 31446) and incorporated herein by reference).

10.13 2011 Equity Incentive Plan adopted May 18, 2011 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on March 23, 2011 (Commission File No. 001-31446) and incorporated herein by reference).

10.14 Form of Notice of Grant of Award of Performance Stock and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).

10.15 Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).

10.16 Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 filed on August 4, 2011 (Commission File no. 001-31446) and incorporated herein by reference).

10.17 Form of Notice of Grant and Award Agreement (Other Stock Award with performance conditions) (filed as Exhibit 10.15 to the Annual Report on Form 10-K for the year ended December 31, 2013 filed on February 26, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.18 2014 Equity Incentive Plan adopted May 15, 2014 (filed as Appendix A to the Definitive Proxy Statement 14-A filed on April 1, 2014 (Commission File No. 001-31446) and incorporated herein by reference.

10.19 Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.1 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.20 Form of Notice of Grant of Nonqualified Stock Option and Award Agreement (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.21 Form of Notice of Grant of Restricted Stock and Award Agreement (filed as Exhibit 10.3 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.22 Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.4 to Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 filed on August 6, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.23 Form of Notice of Grant of Restricted Stock and Award Agreement (Performance Award) (filed as Exhibit 10.23 to the Annual Report on Form 10-K for the year ended December 31, 2014 filed on February 25, 2015 (Commission File No. 001-31446) and incorporated herein by reference).

10.24 Deferred Compensation Plan for Nonemployee Directors adopted May 19, 2004, as amended and restated effective January 1, 2009 (filed as Exhibit 10.18 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.25 Cimarex Energy Co. Supplemental Savings Plan (amended and restated, effective January 1, 2009) (filed as Exhibit 10.19 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001- 31446) and incorporated herein by reference).

10.26 Cimarex Energy Co. Change in Control Severance Plan dated effective April 1, 2005, amended and restated effective January 1, 2009 (filed as Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2008 filed on February 27, 2009 (Commission File No. 001-31446) and incorporated herein by reference).

10.27 Amendment to Cimarex Energy Co. Change in Control Severance Plan dated effective March 19, 2013 (filed as Exhibit 10.1 to the Current Report on Form 8-K filed on March 20, 2013 (Commission File No. 001-31446) and incorporated herein by reference).

10.28 Form of Indemnification Agreement between Cimarex Energy Co. and each of its executive officers and directors (filed as Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2012 filed on February 26, 2013 (Commission File No. 001-31446) and incorporated herein by reference).

10.29 Retention Agreement dated June 9, 2010 (filed as Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2013 filed on February 26, 2014 (Commission File No. 001-31446) and incorporated herein by reference).

10.30 Credit Agreement Dated as of October 16, 2015, by and among Cimarex, the Administrative Agent, the Syndication Agent, the Documentation Agents and the Lenders (filed on October 19, 2015 as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Commission File No. 001-31446) and incorporated herein by reference).

10.31 Form of Notice of Grant of Restricted Stock (Director) and Award Agreement (filed as Exhibit 10.2 to Registrant's Form 8-K (Commission File No. 001-31446) dated November 2, 2015 and incorporated herein by reference).

10.32 Succession Agreement dated August 17, 2015 (filed as Exhibit 10.2 to Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 filed on November 4, 2015 (Commission File No. 001-31446) and incorporated herein by reference).

14.1 Code of Ethics for Chief Executive Officer and Senior Financial Officers (filed as Exhibit 14.1 to the Annual Report on Form 10-K for the year ended December 31, 2003 filed on March 11, 2004 (Commission File No. 001-31446) and incorporated herein by reference).

21.1 Significant Subsidiaries of the Registrant.*

23.1 Consent of KPMG LLP.*

23.2 Consent of DeGolyer and MacNaughton.*

24.1 Power of Attorney of directors of the Registrant.*

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.*

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.*

| | |
|---|---|
| 99.1 | Letter dated January 15, 2016 from DeGolyer and MacNaughton, independent petroleum engineering consulting firm, reporting the results of its audit of Cimarex reserves as of December 31, 2015 of certain selected properties.* |
| 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. * |

## SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) 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.

Date: February 23, 2016

CIMAREX ENERGY CO.

By: /s/ Thomas E. Jorden
Thomas E. Jorden
*Chairman of the Board, Chief Executive Officer and President*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ Thomas E. Jorden<br>Thomas E. Jorden | Chairman of the Board, Director, Chief Executive Officer, and President (Principal Executive Officer) | February 23, 2016 |
| *<br>*Attorney-in-Fact*<br>Joseph R. Albi | Director, Executive Vice President – Chief Operating Officer | February 23, 2016 |
| /s/ G. Mark Burford<br>G. Mark Burford | Vice President and Chief Financial Officer (Principal Financial Officer) | February 23, 2016 |
| /s/ James H. Shonsey<br>James H. Shonsey | Vice President, Controller, Chief Accounting Officer (Principal Accounting Officer) | February 23, 2016 |
| *<br>*Attorney-in-Fact*<br>Hans Helmerich | Director | February 23, 2016 |
| *<br>*Attorney-in-Fact*<br>David A. Hentschel | Director | February 23, 2016 |
| *<br>*Attorney-in-Fact*<br>Harold R. Logan, Jr. | Director | February 23, 2016 |
| *<br>*Attorney-in-Fact*<br>Floyd R. Price | Director | February 23, 2016 |
| *<br>*Attorney-in-Fact*<br>Monroe W. Robertson | Director | February 23, 2016 |

| | | |
|---|---|---|
| *<br>*Attorney-in-Fact*<br>Lisa A. Stewart | Director | February 23, 2016 |
| *<br>*Attorney-in-Fact*<br>Michael J. Sullivan | Director | February 23, 2016 |
| *<br>*Attorney-in-Fact*<br>L. Paul Teague | Director | February 23, 2016 |
| *By: /s/ G. Mark Burford<br>G. Mark Burford<br>*Attorney-in-Fact* | Vice President and Chief<br>Financial Officer (Principal Financial Officer) | February 23, 2016 |

## CORPORATE INFORMATION

Cimarex Energy Co. common stock trades on the New York Stock Exchange under the symbol XEC.

**Corporate Headquarters**
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**Website**
www.cimarex.com

**Stock Transfer Agent**
Continental Stock Transfer & Trust Company
17 Battery Place, 8th Floor
New York, New York 10004
Tel: (888) 509-5580

Communications regarding transfers, lost certificates, duplicate mailings or changes of address should be directed to our transfer agent.

**Independent Registered Public Accounting Firm**
KPMG LLP

**Independent Reservoir Engineers**
DeGolyer and MacNaughton

DESIGN BY: MARK MULVANY GRAPHIC DESIGN (DENVER, COLORADO)

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