CIMAREX ENERGY CO
Form 10-K/A
March 09, 2015
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D C 20549

Form 10-K/A

Amendment No. 1

(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, 2014

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, 2014 was approximately $12.3 billion.

Number of shares of Cimarex Energy Co. common stock outstanding as of February 13, 2015 was 87,597,134.
Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2015 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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EXPLANATORY NOTE

We are filing this Amendment No. 1 (this "Amendment") to our Annual Report on Form 10-K for the year ended December 31, 2014 to include a graph in Item 5 of this report comparing the cumulative five year total return attained by stockholders on Cimarex Energy Co.'s common stock to certain indexes. The graph was inadvertently excluded from the original filing. The associated data related to the graph was included in the original filing.

Our consolidated financial results have not changed from those presented in our original Form 10-K and no other items or disclosures in our Form 10-K have been amended. For ease of reference, we are filing the annual report in its entirety. This Amendment does not reflect events occurring after February 25, 2015, the original filing date of our Form 10 K.

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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

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PART I

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, we are providing “2015 Outlook,” which contains projections for certain 2015 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.

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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.

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 of 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 mitigates financial risk, which enables us to withstand volatility in commodity prices and provide competitive returns to shareholders. Cimarex looks to enhance shareholder returns through quarterly dividends which have increased 100% over the last five years. In June 2014, Cimarex was added to the S&P 500. 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 2010-2014.

Proved Oil and Gas Reserves

In 2014, our total proved reserves grew 25% to 3.1 Tcfe. Proved undeveloped reserves as a percentage of total proved reserves increased to 23% from 20% a year ago. We added 814 Bcfe of new reserves through extensions and discoveries and had upward revisions of 105 Bcfe. Organic growth, as represented by our reserve replacement ratio (excluding reserve purchases and sales) was 2.9 times. The change in our proved reserves is as follows (in Bcfe):

Proved Reserves at December 31, 2013	2,497.0
Revisions of previous estimates	104.8
Extensions and discoveries	813.9
Purchases of reserves	133.6
Production	(317.0)
Sales of reserves	(100.0)
Proved Reserves at December 31, 2014	3,132.3

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

	Years Ended December 31,		
	2014	2013	2012
Total Proved Reserves:			
Gas (Bcf)	1,666.7	1,293.5	1,251.9
Oil (MMBbls)	119.0	108.5	77.9
NGL (MMBbls)	125.3	92.0	89.9
Equivalent (Bcfe)	3,132.3	2,497.0	2,258.8
% Developed	77	80	80

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

Production volumes totaled 869 MMcfe of natural gas equivalent per day, a 25% increase over 2013. Production volumes are comprised of 49% natural gas, 30% oil and 21% 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			
	Gas	Oil	NGL	Equivalent	Gas	Oil	NGL	Equivalent
Years Ended December 31,	(MMcf)	(MBbls)	(MBbls)	(MMcfe)	(MMcf)	(MBbls)	(MBbls)	(MMcfe)
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
2012								
Permian Basin	29,135	8,750	2,480	96,517	79.6	23.9	6.8	263.7
Mid-Continent	80,998	2,210	3,962	118,029	221.3	6.1	10.8	322.5
Other	8,362	556	510	14,754	22.9	1.5	1.4	40.3
Total Company	118,495	11,516	6,952	229,300	323.8	31.5	19.0	626.5
Cana-Woodford	43,222	898	2,830	65,593	118.1	2.5	7.7	179.2

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Years Ended December 31,	Average Realized Price Gas (per Mcf)	Oil (per Bbl)	NGL (per Bbl)	Production Cost (per Mcfe)
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
2012				
Permian Basin	$ 2.93	$ 87.93	$ 30.78	$ 1.50
Mid-Continent	$ 2.86	$ 90.41	$ 29.91	$ 0.77
Other	$ 2.88	$ 105.37	$ 35.95	$ 1.55
Total Company	$ 2.88	$ 89.25	$ 30.66	$ 1.13
Cana-Woodford	$ 2.69	$ 90.64	$ 29.67	$ 0.25

Acquisitions and Divestitures

In 2014 we made property acquisitions totaling $250 million, including a $238 million acquisition of properties in our Cana-Woodford shale play where enhanced completion techniques along with new workover designs were used to increase returns. In addition, we sold interests in various non-core oil and gas properties for $446 million, including non-strategic, high-value acreage in Reagan County, Texas, for $242 million, and other producing properties in southwestern Kansas.

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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 2014, E&D investment totaled $1.88 billion. Of that, 73% was invested in the Permian Basin and 25% in the Mid-Continent region.

In 2014, Cimarex drilled or participated in 312 gross (174.6 net) wells, of which we operated 185 gross (144.5 net) wells. At year-end, we were in the process of drilling or participating in 8 gross (4.0 net) wells and there were 54 gross (31.9 net) wells waiting on completion. A summary of our 2014 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	$ 1,377	171	117	99
Mid-Continent	463	139	57	100
Other	41	2	1	50
	$ 1,881	312	175	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 2014, 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 in the Bone Spring wells via upsized well completions.

The Permian region produced 399 MMcfe per day in 2014, which was 46% of our total company production. Because of strong oil prices in the first nine months, the Permian was our most active drilling region in 2014. Oil production in the Permian Basin in 2014 averaged a record 34,390 barrels per day, a 17% increase over 2013.

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Our Mid-Continent region consists of Oklahoma and the Texas Panhandle. Our activity in 2014 in the Mid-Continent was focused in the Cana-Woodford shale in Oklahoma. Returns increased significantly in this play during 2014 as we implemented well completion techniques in this area that were highly successful in our Delaware Basin Wolfcamp Shale wells in 2013. These improved results, combined with a favorable average product price mix, led to the Mid-Continent region posting the company's strongest returns in 2014. Cimarex also had success in a new zone, the Meramec, which sits above the Woodford Shale. Cimarex is working to delineate the size and potential of the Meramec play.

The Mid-Continent region is our largest producing area. During 2014, production averaged 451.2 MMcfe per day, or 52% of total company production. Production from the region increased 30% in 2014 versus 2013. New completion designs and improved workover technology both contributed to higher production from the region.

Wells Drilled

We drilled the following exploratory and developmental wells in 2014:

	Wells Drilled					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	1	0.4	1	1.0	8	6.3
Dry	1	0.5	3	2.4	5	2.6
Total	2	0.9	4	3.4	13	8.9
Developmental						
Productive	309	173.6	359	181.0	328	177.0
Dry	1	0.1	2	1.0	11	6.1
Total	310	173.7	361	182.0	339	183.1

We have working interests in the following productive wells by region as of December 31, 2014:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	3,757	1,447	490	166
Permian Basin	1,002	511	4,968	991
Other	295	86	108	39
	5,054	2,044	5,566	1,196

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 74% of our proved reserves. In 2014, proved reserves in the Watonga-Chickasha field were approximately 54% 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.

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At December 31, 2014, 63% of our total proved reserves were located in the Mid-Continent region and 36% were in the Permian Basin. We owned an interest in 10,620 gross (3,240 net) productive oil and gas wells. The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2014.

	Gas (Bcf)	Oil (MMBbl)	NGL (MMBbl)	Equivalent (Bcfe)	% of Total Proved Reserves
Mid-Continent	1,280.2	27.8	89.6	1,984.7	63
Permian Basin	370.7	90.1	35.3	1,122.7	36
Other	15.8	1.1	0.4	24.9	1
	1,666.7	119.0	125.3	3,132.3	100

At December 31, 2014, our ten largest producing fields held 80% 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	Mid-Continent	54.0	46.4	13,000'	Woodford
Ford, West	Permian Basin	5.3	59.9	9,500'	Wolfcamp
Lusk	Permian Basin	5.0	55.4	9,500'	Bone Spring
Dixieland	Permian Basin	3.1	98.3	11,000'	Wolfcamp
Two Georges	Permian Basin	2.5	92.7	11,500'	Bone Spring
Cottonwood Draw	Permian Basin	2.4	72.5	3,000'-10,000'	Delaware/Wolfcamp
Red Hills	Permian Basin	2.4	64.3	8,800'	Bone Spring/Wolfcamp
Phantom	Permian Basin	2.3	58.9	11,500'	Bone Spring
Sandbar	Permian Basin	1.9	58.1	7,500'	Bone Spring
Benson	Permian Basin	1.1	83.8	9,500'	Bone Spring
		79.9			

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Acreage

The following table sets forth the gross and net acres of both developed and undeveloped leases held by Cimarex as of December 31, 2014. 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	103,907	80,314	700,703	290,550	804,610	370,864
Texas	28,577	18,314	134,207	58,148	162,784	76,462
	150,715	116,819	834,910	348,698	985,625	465,517
Permian Basin						
New Mexico	83,091	58,017	198,185	138,291	281,276	196,308
Texas	149,724	125,275	186,686	138,684	336,410	263,959
	232,815	183,292	384,871	276,975	617,686	460,267
Other						
Arizona	2,098,481	2,098,481	17,207	—	2,115,688	2,098,481
California	380,782	380,782	—	—	380,782	380,782
Colorado	67,892	44,408	36,414	2,127	104,306	46,535
Gulf of Mexico	25,000	13,000	58,388	13,443	83,388	26,443
Louisiana	5,362	1,601	11,842	3,040	17,204	4,641
Michigan	31,794	31,716	1,183	1,183	32,977	32,899
Montana	35,258	10,379	8,248	1,875	43,506	12,254
Nevada	1,196,299	1,196,299	440	1	1,196,739	1,196,300
New Mexico	1,635,750	1,629,343	18,412	2,578	1,654,162	1,631,921
Texas	36,464	11,976	96,729	36,137	133,193	48,113
Utah	86,068	59,433	26,211	1,575	112,279	61,008
Wyoming	98,801	13,865	43,118	4,796	141,919	18,661
Other	161,978	146,193	9,512	3,486	171,490	149,679
	5,859,929	5,637,476	327,704	70,241	6,187,633	5,707,717
Total	6,243,459	5,937,587	1,547,485	695,914	7,790,944	6,633,501

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									
	2015		2016		2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	10,174	9,865	22,293	20,600	15,859	15,859	325	325	—	—

Permian Basin	27,976	25,659	43,196	42,711	11,066	11,051	19,297	18,309	3,983	3,983
Other	20,754	20,754	200,352	200,175	52,641	52,641	31,412	31,412	67,448	67,448
	58,904	56,278	265,841	263,486	79,566	79,551	51,034	50,046	71,431	71,431
% of undeveloped	0.9	0.9	4.3	4.4	1.3	1.3	0.8	0.8	1.1	1.2

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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 2014 were Enterprise Products Partners L.P. (Enterprise), Sunoco Logistics Partners L.P. (Sunoco) and Oneok Partners, L.P. (Oneok). Enterprise and Sunoco each accounted for 19% of our consolidated revenues in 2014. Oneok accounted for 10% of our 2014 consolidated revenues.

Enterprise is a significant oil purchaser in Oklahoma and West Texas. Sunoco is a significant purchaser of our oil in Southeast New Mexico and Canadian County, Oklahoma. 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, there would be challenges initially, but ample markets to handle the disruption.

Oneok primarily purchases our NGLs and provides gathering, compression and processing services for the majority of our Mid-Continent region gas production. In the event Oneok ceased buying our NGLs, a minimal impact would occur as these products are piped to various processing and storage market areas where we could sell to a different purchaser. In the event Oneok ceased gathering, compressing, and processing our gas, there would be challenges initially, but several other entities exist to fill in the gap.

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, 2014, and 2013, Cimarex had 991 and 908 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. 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, 2014. 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 40 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 20 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 ten 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.

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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 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 these 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), 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. 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, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to a ceiling test and no impairment was necessary. However, a decline of 8% or more in the value of the ceiling limitation would have resulted in an impairment. If commodity prices stay at the current early 2015 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 2015 compared to 2014 is a lower ceiling value each quarter. This will result in ongoing impairments each quarter until prices stabilize or improve. Impairment charges would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

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.

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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.

At December 31, 2014, 23% of our total proved reserves are categorized as proved undeveloped.

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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, 2014.

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. During 2014, we had hedges covering 28% of our oil production and 32% of our gas production. We currently do not have any hedges in place for 2015 or later periods. 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 end-user exception to the clearing requirement and intend to continue to engage in derivative transactions. However, the CFTC is still finalizing rules that will have an impact on our hedging counterparties and possibly end-users as well. 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.

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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 the 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 may be subject to information technology system failures, network disruptions and breaches in data security.

Information system failures, network disruptions and breaches in data security 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. Such system failures could result in the unanticipated disruption of our operations, the processing of transactions, the failure to meet regulatory standards and the reporting of our financial results. While management has taken steps to address these concerns by implementing network security and internal control measures, there can be no assurance that a system failure or data security breach will not have a material adverse effect on our financial condition and results of operations.

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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.

Failing to comply with any of the applicable laws and regulations 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 a permit 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, 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 U.S. Environmental Protection Agency (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

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where hazardous substances may have been released or disposed. The most significant of these environmental laws is 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 are presently 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

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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. We could encounter similar issues if the greater sage grouse is listed as a threatened or endangered species because its habitat includes our areas of operation. A listing decision is anticipated in 2015.

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.

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, in October 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing 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. Moreover, the EPA has indicated that it may develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; however, to date, it has taken no action to do so. In addition to the use of water, hydraulic fracturing fluid contains chemicals or additives designed to optimize production. Many states already require companies to disclose the components of this fluid, and additional states and municipalities, as well as the federal government, may follow with additional regulations regarding disclosure and other issues concerning hydraulic fracturing. Indeed, in May 2013, the BLM published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would continue to require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the

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surface. A final rule is expected to be published in 2015. In May 2013, the Texas Railroad Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Many additional regulations also are being considered by federal, state and municipal governments and agencies, including limiting water withdrawals and usage, water disposal, restricting which additives may be used, implementing local or state-wide hydraulic fracturing moratoriums and temporary or permanent bans in certain environmentally sensitive and other areas. Public sentiment against hydraulic fracturing and shale gas production has become more vocal, which could lead to permitting and compliance requirements becoming more stringent. Consequences of these actions could increase our capital, compliance, and operating costs significantly, as well as delay or halt our ability to develop our oil and gas reserves.

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

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. The current administration intends to finalize proposed climate change rulemaking by 2016. It is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business. Any such future laws and 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, and such requirements also could adversely affect demand for the oil and natural gas that we produce.

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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 23% 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, 2014, 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.

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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:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our subordinated debt;
- make loans to others;
- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all, or substantially all, of our assets and our restricted subsidiaries;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, our revolving credit agreement requires us to maintain a debt to EBITDA ratio (as defined in the credit agreement) of not more than 3.5 and a current ratio (defined to include undrawn borrowings) of greater than 1.0. 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 2 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 6.7% of our total net undeveloped acreage at December 31, 2014. At that date, we had leases representing 56,278 net acres expiring in 2015, 263,486 net acres expiring in 2016, and 79,551 net acres expiring in 2017. 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.

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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 grow 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.

The refining industry may be unable to absorb rising U.S. oil and condensate production; in such a case, the resulting surplus could depress prices and restrict the availability of markets.

The export of oil and certain condensates is restricted under U.S. law. Absent a change in this law or an expansion of U.S. refining capacity, rising U.S. production of oil and condensate could result in a surplus of these products, which could cause prices for these commodities to fall and markets to constrict. If this occurs, our returns on our capital projects would decline, which could make some of our drilling plans uneconomic and which could require us to shut in some of our production. This could have a material adverse effect on our cash flow and profitability.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 3. LEGAL PROCEEDINGS

The information set forth under the heading "Litigation" in Note 11 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.

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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 2014. 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.

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

2013	High	Low	Dividends Paid Per Share
First Quarter	$ 79.69	$ 56.96	$ 0.12
Second Quarter	$ 76.61	$ 62.98	$ 0.14
Third Quarter	$ 97.60	$ 65.17	$ 0.14
Fourth Quarter	$ 113.03	$ 94.11	$ 0.14

The closing price of Cimarex stock as reported on the New York Stock Exchange on February 13, 2015, was $112.01. At December 31, 2014, Cimarex's 87,592,535 shares of outstanding common stock were held by approximately 2,148 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, 2014:

	(a) Number of securities	(b)	(c) Number of securities remaining available for future issuance

Plan Category	to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	384,082	$ 78.19	5,331,312
Equity compensation plans not approved by security holders	—	—	—
Total	384,082	$ 78.19	5,331,312

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In June 2014, Cimarex was added to the S&P 500. 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, 2009 to December 31, 2014.

	12/2009	12/2010	12/2011	12/2012	12/2013	12/2014
Cimarex Energy Co.	$ 100.00	$ 167.87	$ 117.94	$ 110.80	$ 202.75	$ 205.90
S&P 500	$ 100.00	$ 115.06	$ 117.49	$ 136.30	$ 180.44	$ 205.14
Dow Jones US Exploration & Production	$ 100.00	$ 116.74	$ 111.85	$ 118.36	$ 156.05	$ 139.24
S&P Oil & Gas Exploration & Production	$ 100.00	$ 109.28	$ 102.25	$ 105.98	$ 135.11	$ 120.81

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

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.

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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,				
	2014	2013	2012	2011	2010
	(in millions, except per share and proved reserves amounts)				
Operating Results:					
Oil, gas and NGL sales	$ 2,373	$ 1,953	$ 1,582	$ 1,704	$ 1,559
Total Revenues	$ 2,424	$ 1,998	$ 1,624	$ 1,758	$ 1,614
Net income (loss)	$ 507	$ 565	$ 354	$ 530	$ 575
Earnings (loss) per share to common Stockholders:					
Basic	$ 5.79	$ 6.48	$ 4.08	$ 6.17	$ 6.74
Diluted	$ 5.78	$ 6.47	$ 4.07	$ 6.15	$ 6.70
Cash dividends declared per share	$ 0.64	$ 0.56	$ 0.48	$ 0.40	$ 0.32
Balance sheet data:					
Cash and Cash Equivalents	$ 406	$ 5	$ 70	$ 2	$ 114
Oil and Gas Properties, net	$ 6,904	$ 5,966	$ 5,005	$ 4,126	$ 2,922
Goodwill	$ 620	$ 620	$ 620	$ 620	$ 620
Total assets	$ 8,725	$ 7,253	$ 6,305	$ 5,358	$ 4,287
Long-term Obligations					
Long-term debt	$ 1,500	$ 924	$ 750	$ 405	$ 350
Deferred Income Taxes	$ 1,755	$ 1,460	$ 1,121	$ 904	$ 548
Other	$ 194	$ 164	$ 313	$ 302	$ 267
Stockholders' equity	$ 4,501	$ 4,022	$ 3,475	$ 3,131	$ 2,610
Cash flow data:					
Net cash flow provided by operating activities	$ 1,619	$ 1,324	$ 1,193	$ 1,292	$ 1,130
Net cash used in investing activities	$ (1,740)	$ (1,531)	$ (1,415)	$ (1,429)	$ (978)
Net cash provided by (used in) financing activities	$ 522	$ 142	$ 289	$ 25	$ (41)
Proved Reserves:					
Oil (MBbls)	118,992	108,533	77,921	72,322	63,656
Gas (Bcf)	1,667	1,294	1,252	1,216	1,254
NGL (MBbls)	125,273	92,044	89,909	65,815	41,310
Total equivalent (Bcfe)	3,132	2,497	2,259	2,045	1,884

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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. Our operations currently are focused in two main areas: the Permian Basin and the Mid-Continent region. Our Permian Basin region encompasses west Texas and southeast New Mexico. 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 diversified drilling portfolio and limited long-term commitments provide the flexibility to respond quickly to industry volatility.

Growth is generally funded with cash flow provided by operating activities together with bank borrowings, sales of non-strategic assets and occasional public financing. Conservative use of leverage 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.

2014 Summary of Operating and Financial Results

- Average daily production increased by 25% to 868.6 MMcfe/d.
- Proved reserves increased 25% to 3.1 Tcfe.
- We added 813.9 Bcfe of proved reserves from extensions and discoveries, replacing 257% of production.
- Exploration and development expenditures totaled $1.9 billion.
- Revenues reached $2.4 billion, up 21% from 2013.
- Cash flow provided by operating activities totaled $1.6 billion.
- Net income was $507.2 million, or $5.78 per diluted share.

During 2014, our drilling activities were focused almost exclusively in our Permian Basin and Mid-Continent regions. We participated in the drilling and completion of 312 gross (175 net) wells, 185 of which we operated.

Total debt at December 31, 2014 was $1.5 billion comprised entirely of long-term senior notes. Cash on hand was $405.9 million. Our stockholders' equity grew to $4.5 billion from $4.0 billion a year earlier.

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Proved Reserves

	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 Ended December 31, 2013			
	Gas (MMcf)	Oil (MBbl)	NGL (MBbl)	Total Gas Equivalents (MMcfe)
Permian Basin	336,016	85,532	26,157	1,006,152
Mid-Continent	939,224	21,656	65,335	1,461,170
Other	18,260	1,345	552	29,642
Total	1,293,500	108,533	92,044	2,496,964

Year-end 2014 proved reserves grew 25% to 3.1 Tcfe, up from 2.5 Tcfe at year-end 2013. Proved natural gas reserves were 1.7 Tcfe, and both oil and NGLs contributed 0.7 Tcfe each. Increases in the Mid-Continent's proved reserves accounted for 82% of the year-over-year increase and the region now represents 63% of the company's total proved reserves. The remainder of the increase was from the Permian Basin, where most of the rest of our proved reserves are located.

Reserves added from extensions and discoveries totaled 813.9 Bcfe, of which 52% was from natural gas. During 2014, we had net positive reserve revisions of 104.9 Bcfe. This included positive revisions of 16.1 Bcfe due to prices offset by negative revisions of 24.6 Bcfe due to increases in operating expenses, which shortened the economic lives of properties. Performance revisions were a net positive 113.4 Bcfe. This net increase was primarily due to better than expected performance of PUD reserves converted to proved developed reserves during the year.

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.

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 "Supplemental Oil and Gas Information" in Item 8 of this report for further discussion regarding our proved reserves.

Revenues

Almost all of our revenues are derived from sales of 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. Commodity prices are market driven and future prices will continue to fluctuate due to supply and demand factors, seasonality and geopolitical and economic factors.

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Oil sales contributed 55% of our total production revenue for 2014. Gas sales accounted for 29% and NGL sales contributed 16%. A $1.00 per barrel change in our realized oil price would have resulted in a $15.6 million change in revenues. A $0.10 per Mcf change in our realized gas price would have resulted in a $15.5 million change in our gas revenues. A $1.00 per barrel change in NGL prices would have changed revenues by $11.3 million.

The following table presents our average realized commodity prices. Realized prices do not include settlements of commodity hedging contracts.

	Years Ended December 31,		
	2014	2013	2012
Oil Prices:			
Average realized sales price ($/Bbl)	$ 83.70	$ 93.44	$ 89.25
Average WTI Midland price ($/Bbl)	$ 86.18	$ 95.33	$ 91.24
Average WTI Cushing price ($/Bbl)	$ 93.01	$ 97.97	$ 94.20
Gas Prices:			
Average realized sales price ($/Mcf)	$ 4.43	$ 3.76	$ 2.88
Average Henry Hub price ($/Mcf)	$ 4.43	$ 3.65	$ 2.79
NGL Prices:			
Average realized sales price ($/Bbl)	$ 33.14	$ 29.36	$ 30.66

In the fourth quarter of 2014, and through the date of this report, domestic prices for oil, gas and NGLs have declined precipitously. It is likely that prices will continue to fluctuate in the future.

Approximately 80% of our 2014 oil production was in the Permian Basin, the sale of which is tied to the WTI Midland benchmark price. Due to greater industry-wide production in this area, west Texas oil prices have declined relative to the Cushing benchmark. In 2014, the average Midland index price was $6.83 per barrel lower than the average Cushing index price. In 2013, the average Midland price was only $2.64 per barrel lower than the average Cushing price. The overall decline in realized average oil prices together with the decline in the Midland benchmark price resulted in our lower realized oil prices in 2014.

Prior to 2014, our average realized prices for gas and NGLs were net of certain processing fees. Beginning in 2014, these fees are no longer 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 RESULTS OF OPERATIONS below and 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.

Production and other operating expenses

Costs associated with producing oil, gas and NGLs 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 2014, we owned interests in 10,620 gross wells.

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

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

Depreciation, depletion and amortization (DD&A) of our producing properties is computed using the units-of-production method. The economic life of each producing well depends upon the estimated proved reserves for that well, which in turn depend upon the assumed 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, and reclassifications of properties from unproved to proved will impact depletion expense.

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

At December 31, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 8% or more in the value of the ceiling limitation would have resulted in an impairment.

If commodity prices stay at current early 2015 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 2015 compared to 2014 is a lower ceiling value each quarter. This will result in ongoing impairments each quarter until prices stabilize or improve. Impairment charges would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

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 production and other operating expenses is included in RESULTS OF OPERATIONS, below.

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

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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 (in thousands or as indicated)	Years Ended December 31, 2014	2013	Percent Change Between 2014 / 2013	Price / Volume Change Price	Volume	Total
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 — Bbl/d	42,846	36,659	17 %			
Average oil price — per barrel	$ 83.70	$ 93.44	(10) %			
Total gas volume — MMcf	155,128	125,248	24 %			
Gas volume — MMcf/d	425.0	343.1	24 %			
Average gas price — per Mcf	$ 4.43	$ 3.76	18 %			
Total NGL volume — thousand barrels	11,343	7,876	44 %			
NGL volume — Bbl/d	31,078	21,578	44 %			
Average NGL price — per barrel	$ 33.14	$ 29.36	13 %			
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. See Items 1 and 2 of this report for a discussion of 2014 activity in these regions.

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

	Years Ended December 31, 2014	2013
Gas Gathering and Marketing (in thousands):		
Gas gathering and other revenues	$ 49,602	$ 45,441
Gas gathering and other costs	(35,113)	(25,876)
Gas gathering and other margin	$ 14,489	$ 19,565
Gas marketing revenues, net of related costs	$ 1,745	$ 105

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

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Our total operating costs and expenses (not including gas gathering and marketing costs, or income tax expense) in 2014 were $1.58 billion, an increase of 46% compared to $1.08 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 $1.22 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 2014 /	Per Mcfe	
	2014	2013	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
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
	$ 1,575,129	$ 1,076,537	$ 498,592		

Our 2014 DD&A expense increased 31% and accounted for 53% 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.

We expect our 2015 average DD&A rate to fluctuate depending on average realized prices in 2015. Continued lower realized prices during 2015 will cause the value of our oil and gas reserves to decrease and will result in impairments of our oil and gas properties during 2015. In quarters subsequent to an impairment, our DD&A rate will be lower than it is currently and will continue to decline after each subsequent impairment. If 2015 realized prices rebound, we would expect our DD&A rates in subsequent periods to increase moderately each quarter.

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 2014 /	Per Mcfe	
(in thousands)	2014	2013	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

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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, Basis of Presentation – Oil, Gas and NGL Sales, to the Consolidated Financial Statements in this report for additional information.

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

(in thousands)	Years Ended December 31, 2014	2013	Variance Between 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.

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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
Performance restricted stock awards	$ 12,141	$ 11,105	$ 1,036
Service-based restricted stock awards	13,607	12,018	1,589
Restricted stock	25,748	23,123	2,625
Stock option awards	3,057	3,145	(88)
Total stock compensation	28,805	26,268	2,537
Less amounts capitalized to oil and gas properties	(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 7 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 summarizes the net (gains) and losses from settlements and changes in fair value of our derivative contracts. All of our derivative contracts were settled as of December 31, 2014, and we have not entered into any new contracts through the date of this report. See Note 5 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:		
Natural gas contracts	$ 6,750	$ (4,651)
Oil contracts	(10,512)	4,860
(Gain) loss on derivative instruments, net	$ (3,762)	$ 209
Settlement (gains) losses:		
Natural gas contracts	$ 4,287	$ (2,187)
Oil contracts	(11,928)	6,275

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 11 to the Consolidated Financial Statements in Item 8 of this report for further information regarding litigation matters.

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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.

The recent steep decline in oil, gas and NGL prices has resulted in fewer drilling rigs running in the United States as companies cut back on their capital expenditures. Through the first part of February 2015, published oil rig counts are at their lowest since December 2011. The effect of lower exploration and development activity, and thus lower demand, will create downward pressure on the price of oil and gas well equipment and supplies. Accounting rules require that these assets are to be carried at the lower of cost or market. Declines in prices related to our oil and gas well equipment and supplies will likely result in impairments in future quarters. Such impairments would not affect cash flow from operating activities, but would adversely affect our net income and stockholders’ equity.

Income Tax Expense

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

	Years Ended December 31,	
(in thousands)	2014	2013
Current taxes (benefit)	$ 404	$ (689)
Deferred taxes	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 10 to the Consolidated Financial Statements in Item 8 of this report for further information regarding our income taxes.

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RESULTS OF OPERATIONS

2013 compared to 2012

Net income for the year ended December 31, 2013, was $564.7 million ($6.47 per diluted share), up 60% from $353.8 million ($4.07 per diluted share) for the previous year. The increase in 2013 net income was primarily the result of higher revenues from increased production volumes and higher realized prices received for oil and gas production. Net income in 2013 also benefited from a reduction in our estimated exposure to certain litigation expense which had been accruing since 2008. The increases to 2013 net income were partially offset by increased DD&A, other oil and gas operational expenses and income taxes compared to 2012. These changes are discussed further in the analysis that follows.

	Years Ended December 31,		Percent Change Between 2013 / 2012	Price / Volume Change		
Production Revenue	2013	2012		Price	Volume	Total
(in thousands or as indicated)						
Oil sales	$ 1,250,212	$ 1,027,757	22 %	$ 56,062	$ 166,393	$ 222,455
Gas sales	471,045	340,744	38 %	110,218	20,083	130,301
NGL sales	231,248	213,149	8 %	(10,239)	28,338	18,099
Total production revenue	$ 1,952,505	$ 1,581,650	23 %	$ 156,041	$ 214,814	$ 370,855
Total oil volume — thousand barrels	13,380	11,516	16 %			
Oil volume — Bbl/d	36,659	31,463	17 %			
Average oil price — per barrel	$ 93.44	$ 89.25	5 %			
Total gas volume — MMcf	125,248	118,495	6 %			
Gas volume — MMcf/d	343.1	323.8	6 %			
Average gas price — per Mcf	$ 3.76	$ 2.88	31 %			
Total NGL volume — thousand barrels	7,876	6,952	13 %			
NGL volume — Bbl/d	21,578	18,994	14 %			
Average NGL price — per barrel	$ 29.36	$ 30.66	(4) %			
Total equivalent production volumes — MMcfe/d	692.6	626.5	11 %			

As reflected in the table above, our 2013 production revenue was 23% higher than that of 2012. Increased revenue from greater production volumes together with higher realized prices for oil and gas sales were partially offset by lower realized NGL prices.

In 2013, our aggregate production volumes increased 11% compared to 2012. The growth in production resulted from our successful drilling programs in the Permian Basin and Mid-Continent region.

The changes in realized commodity prices were the result of overall market conditions. See Revenues above, for a discussion regarding realized prices.

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

	Years Ended December 31, 2013	2012
Gas Gathering and Marketing (in thousands):		
Gas gathering and other revenues	$ 45,441	$ 43,042
Gas gathering and other costs	(25,876)	(21,965)
Gas gathering and other margin	$ 19,565	$ 21,077
Gas marketing revenues, net of related costs	$ 105	$ (754)

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

In 2013, our total operating costs and expenses of $1.077 billion (not including gas gathering, processing and marketing costs, or income tax expense) benefited from a $142.8 million reduction in our estimated exposure to litigation expense which had been accruing since 2008. Excluding the effect of the litigation reduction, our total operating costs and expenses would have been $1.219 billion, or $188 million (18%) higher than 2012 costs and expenses of $1.031 billion. Analyses of the year-over-year differences are discussed below:

	Years Ended December 31, 2013	2012	Variance Between 2013 / 2012	Per Mcfe 2013	2012
Operating costs and expenses (in thousands):					
DD&A	$ 615,874	$ 513,916	$ 101,958	$ 2.44	$ 2.24
Asset retirement obligation	7,989	13,019	(5,030)	$ 0.03	$ 0.06
Production	286,742	258,584	28,158	$ 1.13	$ 1.13
Transportation, processing and other operating	93,580	57,354	36,226	$ 0.37	$ 0.25
Taxes other than income	112,732	86,994	25,738	$ 0.45	$ 0.38
General and administrative	77,466	54,428	23,038	$ 0.31	$ 0.24
Stock compensation	14,279	21,919	(7,640)	$ 0.06	$ 0.10
(Gain) loss on derivative instruments, net	209	(245)	454	N/A	N/A
Other operating (income) expense, net	(132,334)	24,961	(157,295)	N/A	N/A
	$ 1,076,537	$ 1,030,930	$ 45,607		

Our 2013 DD&A expense increased 20% to $615.9 million, compared to $513.9 million in 2012. The $102.0 million increase accounted for 54% of the aggregate increase in operating costs and expenses, excluding the effect of the litigation reversal. On a per Mcfe basis, 2013 DD&A increased by 9% to $2.44 compared to $2.24 for 2012. About half of the 2013 increase in DD&A was attributable to our higher production volumes. The rest of the increase was a result of a higher DD&A rate. Our DD&A rate has increased because the per unit cost of adding new proved reserves has exceeded the net remaining book basis of proved reserves added in prior years. We expect our average DD&A rate to increase modestly during 2014.

Asset retirement obligation expense declined by 39% to $8.0 million in 2013, compared to $13.0 million in 2012. Half of the decrease resulted from property sales in the latter half of 2012, which lowered our retirement obligation expense during 2013. This decrease was partially offset by increased expense related to newly drilled wells. The remaining decrease was due to higher plugging and abandonment costs in the Permian Basin and Gulf of Mexico during 2012.

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

	Years Ended December 31,		Variance Between 2013 / 2012	Per Mcfe	
(in thousands)	2013	2012		2013	2012
Lease operating expense	$ 226,730	$ 217,891	$ 8,839	$ 0.90	$ 0.95
Workover expense	60,012	40,693	19,319	$ 0.23	$ 0.18
	$ 286,742	$ 258,584	$ 28,158	$ 1.13	$ 1.13

Lease operating expense in 2013 increased by 4% compared to 2012. In 2013, as we continued to put new wells on production, we had increased costs for compression, rental equipment, fuel and overhead. We also had year-over- year increased costs for equipment & maintenance, roads and locations, and environmental expenditures. These increases were partially offset by lower salt water disposal costs and decreased year-over-year costs resulting from property divestitures that occurred in the latter half of 2012. The lower rate per Mcfe was primarily a function of increased production volumes and efficiencies of horizontal well operations in 2013 compared to 2012.

Workover expense increased by 47% from 2012 to 2013. Generally, these costs will fluctuate based on the amount of maintenance and remedial activity planned and/or required during the period. About 60% of the 2013 increase was incurred in the Permian Basin region and the remainder was primarily in the Mid-Continent region.

Our year-over-year transportation and other operating costs increased by 63% during 2013. Transportation costs will vary by product type and area. Increases or decreases in sales volumes, compression charges and fuel costs also have an impact. The increase in these costs is primarily from the growth of our oil and NGL production in the Permian Basin and western Oklahoma.

Taxes other than income are assessed by state and local taxing authorities on production, revenues or the value of properties. Revenue based severance taxes are the largest component of these taxes. Our 2013 taxes increased by 30% compared to 2012. The increase is primarily due to increased severance taxes on higher production volumes. In addition, our 2012 taxes were lower due to a refund for taxes paid in prior years.

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

Variance

(in thousands)	Years Ended December 31, 2013	2012	Between 2013 / 2012
G&A capitalized to oil and gas properties	$ 74,691	$ 66,611	$ 8,080
G&A expense	77,466	54,428	23,038
	$ 152,157	$ 121,039	$ 31,118
G&A expense per Mcfe	$ 0.31	$ 0.24	$ 0.07

Our 2013 overall G&A cost increased 26% compared to 2012. In 2013, we experienced increased costs for salaries and benefits as well as higher rent related to new office facilities. In addition, our 2013 expenditures included $7 million for university endowments established in honor of our former Chairman, F.H. Merelli, and $1 million of contributions for tornado relief in Oklahoma.

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Stock compensation expense consists of non-cash charges resulting from the issuance of restricted stock and stock option awards, net of amounts capitalized. In accordance with our stock incentive plan, such grants are periodically made to non-employee directors, officers and other eligible employees. We have recognized non-cash stock-based compensation cost as follows:

(in thousands)	Years Ended December 31, 2013	2012	Variance Between 2013 / 2012
Performance restricted stock awards	$ 11,105	$ 19,066	$ (7,961)
Service-based restricted stock awards	12,018	12,231	(213)
Restricted stock and units	23,123	31,297	(8,174)
Stock option awards	3,145	2,889	256
Total stock compensation	26,268	34,186	(7,918)
Less amounts capitalized to oil and gas properties	(11,989)	(12,267)	278
Stock compensation	$ 14,279	$ 21,919	$ (7,640)

Expense associated with stock compensation will fluctuate based on the grant-date market value of the award and the number of shares granted. The 2012 cost for the performance awards includes $3.9 million of accelerated compensation expense related to the death of former Chairman, F.H. Merelli. In addition, the 2013 cost for performance awards is approximately $4.3 million lower than 2012 cost due to the timing of awards granted. Almost all of the performance awards granted in 2013 were awarded in mid-December. Awards granted in January of 2010 were fully amortized in early January of 2013, resulting in 2013 having less cost amortized during the year.

See Note 7 to the Consolidated Financial Statements of this report for further discussion regarding our stock-based compensation.

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

Gains and losses on our derivative contracts are a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments. See Note 5 to the Consolidated Financial Statements of this report for further details regarding our derivative instruments.

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

	Years Ended December 31,	
(in thousands)	2013	2012
(Gain) loss on derivative instruments, net:		
Natural gas contracts	$ (4,651)	$ —
Oil contracts	4,860	(245)
(Gain) loss on derivative instruments, net	$ 209	$ (245)
Settlement (gains) losses:		
Natural gas contracts	$ (2,187)	$ —
Oil contracts	6,275	—
Settlement (gains) losses	$ 4,088	$ —

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Other operating (income) expense, net consists of costs related to various legal matters, most of which pertain to litigation and contract settlements, and title and royalty issues. For 2013, we had income of $132.3 million versus expense of $25.0 million for 2012. In December 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 11 to the Consolidated Financial Statements of this report for further information regarding litigation matters.

Other (income) and expense

(in thousands)	Years Ended December 31, 2013	2012	Variance Between 2013 / 2012
Interest expense	$ 54,973	$ 49,317	$ 5,656
Capitalized interest	(31,517)	(35,174)	3,657
Loss on early extinguishment of debt	—	16,214	(16,214)
Other, net	(21,518)	(19,864)	(1,654)
	$ 1,938	$ 10,493	$ (8,555)

Our interest expense includes interest on debt, amortization of financing costs and miscellaneous interest expense. Most of the 11% year-over-year increase of $5.7 million relates to our 5.875% senior notes being outstanding for all of 2013, whereas they were only outstanding for eight months during 2012. See Long-Term Debt below for further information regarding our senior notes.

We capitalize interest on non-producing leasehold costs, the in-progress costs of drilling and completing wells and constructing qualified assets. The 10% decline in 2013 capitalized interest compared to amounts capitalized in 2012 resulted because both the average rate of interest and the amount of costs on which interest is calculated declined in 2013.

In connection with the retirement of our 7.125% senior notes in 2012, we recognized a $16.2 million loss on early extinguishment of debt.

Components of other, net consist of miscellaneous income and expense items that will vary from period to period, including gain or loss on the sale or value of oil and gas well equipment, income and expense associated with other non-operating activities, miscellaneous asset sales and interest income. The 8% increase in 2013 income compared to 2012 was mainly due to net gains on asset sales which were partially offset by lower income from non-operating activities.

Income Tax Expense

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

	Years Ended December 31,	
(in thousands)	2013	2012
Current benefit	$ (689)	$ (1,489)
Deferred taxes	329,700	208,216
	$ 329,011	$ 206,727
Combined Federal and state effective income tax rate	36.8 %	36.9 %

Our income tax expense (benefit) differs from the statutory rate of 35% due to the effects of state income taxes, the Domestic Production Activities allowance and other permanent differences. See Note 10 to the Consolidated Financial Statements of this report for further information regarding our income taxes.

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LIQUIDITY AND CAPITAL RESOURCES

Overview

We strive to maintain an adequate liquidity level to address volatility and risk. Traditional sources of our liquidity are cash flows from operations, cash on hand, available borrowing capacity under our revolving credit facility (Credit Facility), proceeds from sales of non-core properties and occasional public financings.

Our liquidity is highly dependent on prices we receive for the oil, natural gas and NGLs we produce. Prices received heavily influence our revenue, cash flow, profitability, access to capital and future rate of growth. See Revenues above for a comparison of year-over-year price realizations and RESULTS OF OPERATIONS above for analysis of the impact realized prices had on our 2014 revenues.

Prices we receive are determined by prevailing market conditions. Regional and worldwide economic and geopolitical activity, supply versus demand, weather, seasonality and other factors influence market conditions, which often result in significant volatility in commodity prices. In the fourth quarter of 2014, oil, gas and NGL commodity prices began declining significantly and are likely to continue to fluctuate in the future.

We deal with volatility in commodity prices primarily by maintaining flexibility in our capital investment program with a diversified drilling portfolio and limited long-term commitments, which enables us to respond quickly to industry volatility. In addition, we believe our conservative use of leverage and strong balance sheet will mitigate our exposure to lower prices.

From time to time we may enter into hedging agreements. At December 31, 2014, however, we had no hedges outstanding. Hedges limit volatility and increase the predictability of a portion of our cash flow. Hedge transactions also limit potential gains when oil and gas prices exceed the prices established by the hedges. Management will decide whether or not 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.

During 2014, we invested $1.88 billion in exploration and development (E&D) and $250 million in property acquisitions. We also invested $100.6 million in other fixed assets. These investments were largely funded by cash flow provided by operating activities (operating cash flow) and proceeds from property sales. Based on current economic conditions, our 2015 E&D capital expenditures are estimated to range from $900 million to $1.1 billion. Additional capital expenditures for gathering, processing and other fixed assets are expected to approximate $50-80 million.

At December 31, 2014, our long-term debt totaled $1.5 billion and consisted of $750 million of 5.875% senior notes due in 2022 and $750 million of 4.375% senior notes 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, 2014 was 25%. 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 $4.5 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 believe that our operating cash flow and other capital resources will be adequate to meet our needs for planned capital expenditures, working capital, debt service and dividend payments in 2015 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.

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The following table presents our sources and uses of cash and cash equivalents from 2012 to 2014. 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)	2014	2013	2012
Sources of cash and cash equivalents:			
Operating cash flow	$ 1,619,365	$ 1,324,348	$ 1,192,764
Sales of oil and gas and other assets	458,394	93,164	312,622
Net increase in bank debt	—	174,000	—
Increase in other long-term debt	750,000	—	750,000
Issuance of common stock and other	11,898	14,494	11,433
Total sources of cash and cash equivalents	2,839,657	1,606,006	2,266,819
Uses of cash and cash equivalents:			
Oil and gas capital expenditures	(2,108,250)	(1,572,288)	(1,662,707)
Other capital expenditures	(90,611)	(51,913)	(64,987)
Net decrease in bank debt	(174,000)	—	(55,000)
Decrease in other long-term debt	—	—	(363,595)
Financing costs incurred	(11,616)	(100)	(13,821)
Dividends paid	(53,849)	(46,712)	(39,577)
Total uses of cash and cash equivalents	(2,438,326)	(1,671,013)	(2,199,687)
Net increase (decrease) in cash and cash equivalents	$ 401,331	$ (65,007)	$ 67,132
Cash and cash equivalents at end of year	$ 405,862	$ 4,531	$ 69,538

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

Net cash flow provided by operating activities (operating cash flow) for 2014 increased $295 million to $1.62 billion compared to $1.32 billion for 2013. The 22% increase was primarily a result of 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. Similarly, the 11% increase in 2013 operating cash flow compared to 2012 was mostly due to higher production volumes and increased realized prices for oil and natural gas, partially offset by lower realized prices for NGLs and increased operating expenses.

In 2014, net cash flow used for investing activities was $1.74 billion, compared to $1.53 billion for 2013 and $1.42 billion for 2012. In 2014, our E&D and other capital investments were $2.20 billion, which were partially offset by proceeds from asset sales of $458 million. Our 2013 E&D and other capital expenditures were $1.62 billion, which were partially offset by asset sales of $93 million. For 2012, our E&D and other capital expenditures of $1.73 billion were partially offset by asset sales of $313 million.

Net cash flow provided by financing activities in 2014 was $522 million compared to $142 million in 2013 and $289 million in 2012. During 2014, we issued $750 million of senior notes and had $12 million of proceeds from issuance of common stock from employee option exercises. These cash inflows were partially offset by payments of $174 million on our Credit Facility, $12 million for financing costs and dividend payments of $54 million.

In 2013, financing activity cash inflows came from net bank borrowings of $174 million together with net proceeds from the issuance of common stock from employee option exercises and other of $14 million, which were partially offset by $46 million of dividend payments. During 2012, cash proceeds from issuance of $750 million of senior notes and $11 million of proceeds from employee stock option exercises were offset by debt payments of $418 million, financing costs of $14 million and dividend payments of $40 million.

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Reconciliation of Adjusted Cash Flow from Operations

	Years Ended December 31,		
(in thousands)	2014	2013	2012
Net cash provided by operating activities	$ 1,619,365	$ 1,324,348	$ 1,192,764
Change in operating assets and liabilities	14,847	63,840	(58,049)
Adjusted cash flow from operations	$ 1,634,212	$ 1,388,188	$ 1,134,715

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 sets forth certain historical information regarding capitalized expenditures for oil and gas acquisitions, exploration and development activities and property sales:

	Years Ended December 31,	
(in thousands)	2014	2013
Acquisitions:		
Proved	$ 138,508	$ 682
Unproved	111,225	36,396
	249,733	37,078
Exploration and development:		
Land & seismic	176,061	165,107
Exploration	40,084	46,290
Development	1,664,877	1,354,098
	1,881,022	1,565,495
Property sales	(446,107)	(61,503)
	$ 1,684,648	$ 1,541,070

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.

During 2014, approximately 73% of our $1.88 billion E&D expenditures were in the Permian Basin and 25% were in our Mid-Continent region. We participated in the drilling and completion of 312 gross (175 net) wells, 185 of which we operated.

Of the total wells drilled, 171 gross (117 net) were in the Permian Basin and 139 gross (57 net) were in the Mid-Continent region. At year-end 54 gross (32 net) wells were awaiting completion with 39 gross (27 net) in the Permian Basin and 15 gross (5 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.

Our 2015 E&D capital investment is presently expected to range from $900 million to $1.1 billion, which will again be directed toward drilling in the Permian Basin and Mid-Continent regions. We intend to fund our capital program with cash on hand at December 31, 2014 and cash flow from 2015 operating activities. Occasional sales of non-core assets 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 throughout the year.

In the ordinary course of business we actively evaluate opportunities to purchase properties that utilize our technical expertise, 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 3 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.

Financial Condition

During 2014, our total assets increased $1.5 billion (20%) to $8.7 billion, up from $7.2 billion at December 31, 2013. The increase was primarily due to a $938 million increase in net oil and gas properties and a $401 million increase in cash.

Total liabilities at year-end 2014 increased to $4.2 billion, up $1.0 billion (31%) from $3.2 billion at year-end 2013. During 2014, net long-term debt increased by $576 million and deferred income taxes increased $295 million.

On December 31, 2014, stockholders’ equity totaled $4.5 billion, an increase of $0.5 billion (12%) from $4.0 billion at December 31, 2013. The increase resulted from our 2014 net income of $507 million less $56 million of dividends.

Long-Term Debt

Long-term debt at year end 2014 and 2013 consisted of the following:

	December 31,	
(in thousands)	2014	2013
Bank debt	$ —	$ 174,000
5.875% Senior Notes, due May 1, 2022	750,000	750,000
4.375% Senior Notes, due June 1, 2024	750,000	—
Total long-term debt	$ 1,500,000	$ 924,000

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.

Bank Debt

In May 2014 we amended our senior unsecured revolving Credit Facility to extend the maturity date two years to July 14, 2018 and lowered the margins applicable to loans and commitments. The amendment also raised our borrowing base from $2.25 billion to $2.5 billlion until the next regular annual redetermination date scheduled for April 15, 2015. The borrowing base is determined at the discretion of the lenders based on the value of our proved reserves. Our aggregate commitments remained unchanged at $1 billion.

At December 31, 2014, we had letters of credit outstanding of $2.5 million, leaving an unused borrowing availability of $997.5 million. During 2014, we had average daily bank debt outstanding of $132.6 million, compared to $159.3 million in 2013. Our highest amount of bank borrowings outstanding during 2014 was $515.0 million in May. During 2013, the highest amount of outstanding bank borrowings was $300 million in December.

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

The Credit Facility has a number of financial and non-financial covenants of which we were in compliance with at December 31, 2014. For further information see Note 2 to the Consolidated Financial Statements in Item 8 of this report.

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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.

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.

In the second quarter of 2012, we completed a cash tender offer to purchase all of our outstanding 7.125% senior notes. We recognized a $16.2 million loss on early extinguishment of debt during the second quarter of 2012.

Each of our outstanding senior notes is governed by an indenture containing certain covenants, events of default and other restrictive provisions. Interest on each of the senior notes is payable semi-annually.

Working Capital Analysis

Our working capital fluctuates primarily as a result of our realized commodity prices, changes in receivables and payables related to our operating and exploration and development activities and changes in our oil and gas well equipment and supplies balance.

At December 31, 2014, we had working capital of $155.5 million, an increase of $369.5 million compared to a deficit of $214.0 million at December 31, 2013.

Working capital increases consisted of the following:

- Cash and cash equivalents increased by $401.3 million primarily from third quarter asset sales.
- Operations-related accounts receivable increased $44.5 million.
- Oil and gas well equipment and supplies increased by $23.0 million.

Increases in working capital were partially offset by the following:

- Operations-related accounts payable and accrued liabilities increased by $66.0 million.
- Accrued liabilities related to our E&D expenditures increased by $27.6 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.

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Dividends

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

	2014	2013	2012
Dividend declared (in millions)	$ 55.7	$ 48.4	$ 41.3
Dividend per share	$ 0.64	$ 0.56	$ 0.48

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, 2014, 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, 2014, 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)	642,188	76,876	153,750	153,750	257,812
Operating leases	120,949	10,166	22,050	20,938	67,795
Drilling commitments (2)	259,437	240,450	18,987	—	—
Gathering facilities and pipelines (3)	6,878	6,878	—	—	—
Asset retirement obligation (4)	173,008	13,216	— (4)	— (4)	— (4)
Other liabilities (5)	84,178	20,166	44,064	—	19,948
Firm Transportation	357	321	36	—	—

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

(2) We have commitments of $207.7 million to finish drilling and completing wells in progress at December 31, 2014. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $51.7 million.
(3) We have projects in New Mexico and Texas where we are constructing gathering facilities and pipelines. At December 31, 2014, we had commitments of $6.9 million relating to this construction.
(4) We have not included the long-term asset retirement obligations because we are not able to precisely predict the timing of these amounts.
(5) Other includes the estimated value of our commitment associated with our benefit obligations and other miscellaneous commitments.

At December 31, 2014, we had firm sales contracts to deliver approximately 30.8 Bcf of natural gas over the next 12 months. In total, our financial exposure would be approximately $91.7 million should this gas not be delivered. Our exposure will fluctuate with price volatility and actual volumes delivered, however, we believe we have no financial exposure from these contracts based on our current proved reserves and production levels. In the normal course of business we have various other delivery commitments which are not material individually or in the aggregate. All of the noted commitments were routine and were made in the normal course of our business.

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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.

2015 Outlook

Based on current economic conditions, our 2015 E&D capital expenditures are estimated to range from $900 million to $1.1 billion, to be allocated almost equally between our Permian Basin and Mid-Continent regions. Investments in gathering, processing and other fixed assets are expected to approximate $50-80 million.

We currently project production growth of 3% to 8%, or an average of 895-935 MMcfe per day, in 2015. As has been our historical practice, we regularly review capital expenditures throughout the year and will adjust our investments based on changes in commodity prices, service costs and drilling success. We have the flexibility to adjust our capital expenditures based upon market conditions.

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. 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 2014, 23% 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” 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

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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. Recorded impairment of oil and gas properties is not reversible.

Quarterly and annual ceiling tests are primarily impacted by commodity prices, reserve quantities added and produced, overall exploration and development costs, depletion expense and deferred taxes. As of December 31, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test, and no impairment was necessary. However, a decline of 8% or more in the value of the ceiling limitation would have resulted in an impairment. If commodity prices stay at the current 2015 rates, decline further, or if there is a negative impact on one or more of the other components of the calculation, we will incur a full cost ceiling impairment related to our oil and gas properties in future quarters. An impairment charge would have no effect on liquidity or our capital resources, but would adversely affect our results of operations in the period incurred.

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, 2014, 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 11 to the Consolidated Financial Statements in this report for further information regarding litigation and other commitments and contingencies.

At December 31, 2014, 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 9 to the Consolidated Financial Statements 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 10 to the Consolidated Financial Statements of this report for additional information regarding our income taxes.

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers (Topic 606). 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. We must comply with this ASU beginning in fiscal year 2017 and early adoption is not permitted. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. We are currently evaluating the potential impact of this guidance, but at this time, do not expect that the adoption of this standard will have a material effect on our financial position or results of operation.

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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. 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, 2014, we had no hedges in place.

Counterparty credit risk did not have a significant effect on our cash flow calculations and commodity derivative valuations. This is primarily because we mitigated our exposure to any single counterparty by contracting with a number of financial institutions, each of which had a high credit rating and was a member of our bank credit facility. See Note 5 to the Consolidated Financial Statements of this report for additional information regarding our derivative instruments.

Interest Rate Risk

At December 31, 2014, 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 2 and Note 4 to the Consolidated Financial Statements in this report for additional information regarding debt.

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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.

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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, 2014 and 2013, and the related consolidated statements of income and comprehensive income, stockholders' equity, and cash flows for each of the years in the three year period ended December 31, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2014, 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, 2014, 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 25, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Denver, Colorado

February 25, 2015

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CIMAREX ENERGY CO.

CONSOLIDATED BALANCE SHEETS

(in thousands, except share and per share information)

	December 31, 2014	2013
Assets		
Current assets:		
Cash and cash equivalents	$ 405,862	$ 4,531
Accounts receivable:		
Trade, net of allowance	134,443	83,070
Oil and gas sales, net of allowance	259,220	265,050
Gas gathering, processing, and marketing, net of allowance	18,009	19,102
Other	436	532
Oil and gas well equipment and supplies	89,780	66,772
Deferred income taxes	13,475	16,854
Derivative instruments	—	4,268
Prepaid Expenses	9,356	7,867
Other current assets	1,223	1,093
Total current assets	931,804	469,139
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	14,402,064	12,863,961
Unproved properties and properties under development, not being amortized	759,149	585,361
	15,161,213	13,449,322
Less—accumulated depreciation, depletion and amortization	(8,257,502)	(7,483,685)
Net oil and gas properties	6,903,711	5,965,637
Fixed assets, less accumulated depreciation of $175,453 and $167,675	211,031	146,918
Goodwill	620,232	620,232
Other assets, net	58,515	51,209
	$ 8,725,293	$ 7,253,135
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 102,276	$ 80,918
Gas gathering, processing, and marketing	35,775	35,192
Accrued liabilities:		
Exploration and development	200,929	173,298
Taxes other than income	26,950	27,509
Other	219,505	211,688
Derivative instruments	—	389
Revenue payable	190,892	154,173
Total current liabilities	776,327	683,167

Long-term debt	1,500,000	924,000
Deferred income taxes	1,754,706	1,459,841
Asset retirement obligation	159,792	126,968
Other liabilities	33,836	36,951
Total liabilities	4,224,661	3,230,927
Commitments and contingencies		
Stockholders’ equity:		
Preferred stock, $0.01 par value, 15,000,000 shares authorized, no shares issued	—	—
Common stock, $0.01 par value, 200,000,000 shares authorized, 87,592,535 and 87,152,197 shares issued, respectively	876	872
Paid-in capital	1,997,080	1,970,113
Retained earnings	2,501,574	2,050,034
Accumulated other comprehensive income	1,102	1,189
	4,500,632	4,022,208
	$ 8,725,293	$ 7,253,135

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(in thousands, except per share data)

	Years Ended December 31, 2014	2013	2012
Revenues:			
Oil sales	$ 1,308,958	$ 1,250,212	$ 1,027,757
Gas sales	687,930	471,045	340,744
NGL Sales	375,941	231,248	213,149
Gas gathering and other	49,602	45,441	43,042
Gas marketing, net of related costs of $256,836, $187,772 and $86,813 respectively	1,745	105	(754)
	2,424,176	1,998,051	1,623,938
Costs and expenses:			
Depreciation, depletion and amortization	806,021	615,874	513,916
Asset retirement obligation	10,082	7,989	13,019
Production	342,304	286,742	258,584
Transportation, processing, and other operating	195,414	93,580	57,354
Gas gathering and other	35,113	25,876	21,965
Taxes other than income	128,793	112,732	86,994
General and administrative	81,160	77,466	54,428
Stock compensation	15,001	14,279	21,919
(Gain) loss on derivative instruments, net	(3,762)	209	(245)
Other operating (income) expense, net	116	(132,334)	24,961
	1,610,242	1,102,413	1,052,895
Operating income	813,934	895,638	571,043
Other (income) and expense:			
Interest expense	72,865	54,973	49,317
Capitalized interest	(35,925)	(31,517)	(35,174)
Loss on early extinguishment of debt	—	—	16,214
Other, net	(28,907)	(21,518)	(19,864)
Income before income tax	805,901	893,700	560,550
Income tax expense	298,697	329,011	206,727
Net income	$ 507,204	$ 564,689	$ 353,823
Earnings per share to common stockholders:			
Basic			
			$
Distributed	$ 0.64	$ 0.56	$ 0.48
Undistributed	5.15	5.92	3.60
	$ 5.79	$ 6.48	$ 4.08
Diluted			

			$
Distributed	$ 0.64	$ 0.56	$ 0.48
Undistributed	5.14	5.91	3.59
	$ 5.78	$ 6.47	$ 4.07
Comprehensive income:			
Net income	$ 507,204	$ 564,689	$ 353,823
Other comprehensive income:			
Change in fair value of investments, net of tax	(87)	715	488
Total comprehensive income	$ 507,117	$ 565,404	$ 354,311

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years Ended December 31, 2014	2013	2012
Cash flows from operating activities:			
Net income	$ 507,204	$ 564,689	$ 353,823
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	806,021	615,874	513,916
Asset retirement obligation	10,082	7,989	13,019
Deferred income taxes	298,293	329,700	208,216
Stock compensation	15,001	14,279	21,919
(Gain) loss on derivative instruments	(3,762)	209	(245)
Settlements on derivative instruments	7,641	(4,088)	—
Loss on early extinguishment of debt	—	—	16,214
Changes in non-current assets and liabilities	(2,440)	(141,215)	3,125
Other, net	(3,828)	751	4,728
Changes in operating assets and liabilities:			
Receivables, net	(35,133)	(64,780)	56,435
Other current assets	(25,428)	14,234	4,209
Accounts payable and other current liabilities	45,714	(13,294)	(2,595)
Net cash provided by operating activities	1,619,365	1,324,348	1,192,764
Cash flows from investing activities:			
Oil and gas expenditures	(2,108,250)	(1,572,288)	(1,662,707)
Sales of oil and gas assets	449,981	61,503	311,562
Sales of other assets	8,413	31,661	1,060
Other capital expenditures	(90,611)	(51,913)	(64,987)
Net cash used by investing activities	(1,740,467)	(1,531,037)	(1,415,072)
Cash flows from financing activities:			
Net bank debt borrowings	(174,000)	174,000	(55,000)
Proceeds from other long-term debt	750,000	—	750,000
Other long-term debt payments	—	—	(363,595)
Financing costs incurred	(11,616)	(100)	(13,821)
Dividends paid	(53,849)	(46,712)	(39,577)
Issuance of common stock and other	11,898	14,494	11,433
Net cash provided by financing activities	522,433	141,682	289,440
Net change in cash and cash equivalents	401,331	(65,007)	67,132
Cash and cash equivalents at beginning of period	4,531	69,538	2,406

Cash and cash equivalents at end of period	$ 405,862	$ 4,531	$ 69,538

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

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CIMAREX ENERGY CO.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(in thousands)

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (loss)	Total Stockholders' Equity
Balance, December 31, 2011	85,774	$ 858	$ 1,908,506	$ 1,221,263	$ (14)	$ 3,130,613
Dividends	—	—	—	(41,318)	—	(41,318)
Net Income	—	—	—	353,823	—	353,823
Unrealized change in fair value of investments, net of tax	—	—	—	—	488	488
Issuance of restricted stock awards	562	5	(5)	—	—	—
Common stock reacquired and retired	(184)	(2)	(11,015)	—	—	(11,017)
Restricted stock forfeited and retired	(141)	(1)	1	—	—	—
Exercise of stock options	559	6	11,427	—	—	11,433
Vesting of restricted stock units	26	—	—	—	—	—
Stock-based compensation	—	—	34,085	—	—	34,085
Stock-based compensation tax benefit			(3,371)	—	—	(3,371)
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

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

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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

Our oil and gas well equipment and supplies are valued at the lower of cost or market using weighted average cost. The steep decline in oil, gas and NGL prices has resulted in fewer drilling rigs running in the United States as companies cut back on their capital expenditures. Through the first part of February 2015, published oil rig counts are at their lowest since December 2011. The effect of lower exploration and development activity, and thus lower demand, will create downward pressure on the price of oil and gas well equipment and supplies. GAAP requires that these assets are to

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be carried at the lower of cost or market. Declines in prices related to our oil and gas well equipment and supplies will likely result in impairments in future quarters.

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. Revenue calculations in the reserves are based on the unweighted average first-day-of-the-month prices for the prior 12 months. Changes in proved reserve estimates (whether based upon quantity revisions or commodity prices) will cause corresponding changes to the full cost ceiling limitation. If net capitalized costs subject to amortization exceed this limit, the excess would be charged to expense. Any recorded impairment of oil and gas properties is not reversible at a later date.

Our quarterly and annual ceiling tests are primarily impacted by commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. As of December 31, 2014, the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test and no impairment was necessary. However, a decline of 8% or more in the value of the ceiling limitation would have resulted in an impairment. If commodity prices stay at the current early 2015 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 2015 compared to 2014 is a lower ceiling value each quarter. This will result in ongoing impairments each quarter until prices stabilize or improve. Impairment charges would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

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.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 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, 2014, 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 income and comprehensive income.

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.

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 5 for additional information regarding our derivative instruments.

Income Taxes

Cimarex records 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. The company routinely assesses the realizability of its deferred tax assets. If the company concludes 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.

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 10 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 11 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 9 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

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CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 7 for additional information regarding our stock-based compensation.

Earnings 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 8 for additional information regarding our earnings per share.

Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers (Topic 606). 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. We must comply with this ASU beginning in fiscal year 2017 and early adoption is not permitted. Entities can choose to apply the standard using either the full retrospective approach or a modified retrospective approach. We are currently evaluating the potential impact of this guidance, but at this time, do not expect that the adoption of this standard will have a material effect on our financial position or results of operation.

Subsequent Events

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

2. LONG-TERM DEBT

A summary of our debt is as follows:

	December 31,	
(in thousands)	2014	2013
Bank debt	$ —	$ 174,000
5.875% Senior Notes, due May 1, 2022	750,000	750,000
4.375% Senior Notes, due June 1, 2024	750,000	—
Total long-term debt	$ 1,500,000	$ 924,000

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.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Bank Debt

In May 2014, we amended our senior unsecured revolving credit facility (Credit Facility) to extend the maturity date two years to July 14, 2018 and lowered the margins applicable to loans and commitments. The amendment also raised our borrowing base from $2.25 billion to $2.5 billion until the next regular annual redetermination date scheduled for April 15, 2015. The borrowing base under the Credit Facility is determined at the discretion of the lenders based on the value of our proved reserves. Our aggregate commitments remained unchanged at $1 billion.

As of December 31, 2014, we had letters of credit outstanding under the Credit Facility of $2.5 million, leaving an unused borrowing availability of $997.5 million.

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

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

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.

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.

In the second quarter of 2012, we completed a cash tender offer to purchase all of our outstanding 7.125% senior notes. We recognized a $16.2 million loss on early extinguishment of debt during the second quarter of 2012.

Each of our outstanding senior notes is governed by an indenture containing certain covenants, events of default and other restrictive provisions. Interest on each of the senior notes is payable semi-annually.

3. 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.

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.

CIMAREX ENERGY CO.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

During 2012, we sold interests in non-core oil and gas assets for $306 million. Of this total, $290 million was related to non-core oil and gas assets located in Texas. We had property acquisitions of $33.5 million during 2012, most of which were undeveloped acreage in the Permian Basin.

4. FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The FASB has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

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

December 31, 2014: (in thousands)	Carrying Amount	Fair Value
Financial Assets (Liabilities):		
5.875% Notes due 2022	$ (750,000)	$ (776,250)
4.375% Notes due 2024	$ (750,000)	$ (720,000)

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

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

Debt (Level 1)

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

The fair value for our 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 internal discounted cash flow calculations. Cash flows are based on the stated contract prices and current and published forward commodity price curves, adjusted for volatility. The cash flows are risk adjusted relative to non-performance for both our counterparties and our liability positions. Please see Note 5 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, 2014 and 2013, respectively, are liabilities of approximately $42.0 million and $43.7 million representing the amount by which checks issued, but not yet presented to our banks for collection, exceeded balances in applicable bank accounts. Also included in "accrued liabilities, other" at December 31, 2014 and 2013, respectively, are accrued payroll related general and administrative expenses of $44.2 million and $41.9 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, 2014, the allowance for doubtful accounts totaled $1.5 million. At December 31, 2013, the allowance for doubtful accounts was $6.0 million.

Major Customers

Our major customers during 2014 were Enterprise Products Partners L.P. (Enterprise), Sunoco Logistics Partners L.P. (Sunoco) and Oneok Partners, L.P. (Oneok). Enterprise and Sunoco each accounted for 19% of our consolidated revenues in 2014. Oneok accounted for 10% of our 2014 consolidated revenues. During 2013, Enterprise and Sunoco were our major customers and accounted for 24% and 22% of our consolidated revenues, respectively.

Enterprise is a significant oil purchaser in Oklahoma and West Texas. Sunoco is a significant purchaser of our oil in Southeast New Mexico and Canadian County, Oklahoma. 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, there would be challenges initially, but ample markets to handle the disruption.

Oneok primarily purchases our NGLs and provides gathering, compression and processing services for the majority of our Mid-Continent region gas production. In the event Oneok ceased buying our NGLs, a minimal impact would occur as these products are piped to various processing and storage market areas where we could sell to a different purchaser. In the event Oneok ceased gathering, compressing, and processing our gas, there would be challenges initially, but several other entities exist to fill in the gap.

5. 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.

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

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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)	2014	2013	2012
Gain (loss) on derivative instruments, net	$ 3,762	$ (209)	$ 245
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. We entered into oil and gas contracts at the end of 2013 and the beginning of 2014. All of these contracts were settled as of December 31, 2014 and we have not entered into any new contracts. Depending on oil and gas futures markets and management's view of underlying supply and demand trends, we may hedge in the future.

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

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

We were exposed to financial risks associated with our derivative contracts from non-performance by our counterparties. We mitigated our exposure to any single counterparty by contracting with a number of financial institutions, each of which had a high credit rating and was 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.

6. CAPITAL STOCK

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At December 31, 2014, there were no shares of preferred stock outstanding. See our Consolidated Statements of Stockholders' Equity for detailed capital stock activity.

Dividends

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

	2014	2013	2012
Dividend declared (in millions)	$ 55.7	$ 48.4	$ 41.3
Dividend per share	$ 0.64	$ 0.56	$ 0.48

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7. STOCK-BASED and OTHER COMPENSATION

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

	Years Ended December 31,		
(in thousands)	2014	2013	2012
Performance stock awards	$ 12,141	$ 11,105	$ 19,066
Service-based stock awards	13,607	12,018	12,231
Restricted stock awards	25,748	23,123	31,297
Stock option awards	3,057	3,145	2,889
	28,805	26,268	34,186
Less amounts capitalized to oil and gas properties	(13,804)	(11,989)	(12,267)
Compensation expense	$ 15,001	$ 14,279	$ 21,919

Historical amounts may not be representative of future amounts as additional awards may be granted. The 2012 compensation cost for the performance awards includes $3.9 million of accelerated vesting related to the death of former Chairman, F.H. Merelli. In addition, the 2013 cost for performance awards is approximately $4.3 million lower than 2012 costs due to the timing of awards granted. Almost all of the performance awards granted in 2013 were awarded in mid-December. Awards granted in early January of 2010 were fully amortized in January of 2013, resulting in 2013 having less costs amortized during the year.

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 primary purposes of the 2014 Plan are to increase the number of shares available in connection with awards, provide flexibility in the types of available awards and design of awards, modify certain individual award limits and revise the performance measures for qualified performance-based awards. 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,					
	2014		2013		2012	
	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	316,441	$ 83.22	298,000	$ 77.75	262,770	$ 43.22
Service-based stock awards	170,402	$ 136.72	281,236	$ 72.89	299,499	$ 54.17
Total restricted stock awards	486,843	$ 101.95	579,236	$ 75.39	562,269	$ 49.05

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

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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	1,035,032	$ 68.41	828,802	$ 65.27
Vested	(106,817)	$ 37.91	(195,664)	$ 73.01
Granted	170,402	$ 136.72	316,441	$ 83.22
Canceled	(62,200)	$ 69.91	(72,368)	$ 73.01
Outstanding end of period	1,036,417	$ 82.69	877,211	$ 69.38

The total fair value of restricted stock that vested was $34.1 million in 2014, $25.7 million in 2013, and $36.0 million in 2012.

Unrecognized compensation cost related to unvested restricted shares at December 31, 2014 was $83.9 million. We expect to recognize that cost over a weighted average period of 2.2 years.

Restricted Units

As of December 31, 2014 and 2013, 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.

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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, 2014	2013	2012
Options granted	82,500	144,400	152,800
Weighted average grant-date fair value	$ 41.69	$ 21.64	$ 20.55
Weighted average exercise price	$ 139.02	$ 72.25	$ 51.92
Total Fair Value (in thousands)	$ 3,439	$ 3,125	$ 3,140
Expected years until exercise	4.0	4.0	5.3
Expected stock volatility	36.7 %	38.6 %	47.4 %
Dividend yield	0.5 %	0.8 %	0.9 %
Risk-free interest rate	1.8 %	1.4 %	0.6 %

Information about outstanding stock options is summarized below.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Aggregate Intrinsic Value (in thousands)
Outstanding as of January 1, 2014	531,016	$ 59.78		
Exercised	(211,258)	$ 56.32		
Granted	82,500	$ 139.02		
Forfeited	(18,176)	$ 70.67		
Outstanding as of December 31, 2014	384,082	$ 78.19	5.0 Years	$ 13,260
Exercisable as of December 31, 2014	178,926	$ 59.19	4.1 Years	$ 8,319

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

	Years Ended December 31,		
(in thousands)	2014	2013	2012
Number of options exercised	211,258	276,069	558,419
Cash received from option exercises	$ 11,899	$ 14,494	$ 11,433
Tax benefit from option exercises included in paid-in-capital (1)	$ —	$ —	$ 76
Intrinsic value of options exercised	$ 15,384	$ 10,109	$ 22,482
Grant-date fair value of options vested	$ 4,419	$ 2,521	$ 2,560

(1) No tax benefit is recorded until the benefit reduces current taxes payable.

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The following summary reflects the status of non-vested stock options as of December 31, 2014 and changes during the year.

	Options	Weighted Average Grant-Date Fair Value	Weighted Average Exercise Price
Non-vested as of January 1, 2014	343,014	$ 21.64	$ 63.81
Vested	(202,182)	$ 21.86	$ 62.48
Granted	82,500	$ 41.69	$ 139.02
Forfeited	(18,176)	$ 23.24	$ 70.67
Non-vested as of December 31, 2014	205,156	$ 29.35	$ 94.76

As of December 31, 2014, there was $4.1 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 costs related to the plan were $11.0 million for 2014. During 2013 and 2012, such costs were $9.0 million and $8.2 million, respectively.

8. EARNINGS PER SHARE

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

	Years Ended December 31,		
(in thousands, except per share data)	2014	2013	2012
Basic:			
Net income	$ 507,204	$ 564,689	$ 353,823
Participating securities' share in earnings	(9,906)	(11,091)	(6,753)
Net income applicable to common stockholders	$ 497,298	$ 553,598	$ 347,070
Diluted:			
Net income	$ 507,204	$ 564,689	$ 353,823
Participating securities' share in earnings	(9,891)	(11,076)	(6,732)

Net income applicable to common stockholders	$ 497,313	$ 553,613	$ 347,091
Shares:			
Basic shares outstanding	85,679	85,288	84,757
Incremental shares from assumed exercise of stock options	131	121	277
Fully diluted common stock	85,810	85,409	85,034
Excluded (1)	94	251	414
Earnings per share to common stockholders (2):			
Basic	$ 5.79	$ 6.48	$ 4.08
Diluted	$ 5.78	$ 6.47	$ 4.07

(1) Inclusion of certain outstanding stock options would have an anti-dilutive effect.
(2) Earnings per share are based on actual figures rather than the rounded figures presented.

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9. 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, 2014 and 2013.

(in thousands)	2014	2013
Asset retirement obligation at January 1,	$ 154,026	$ 185,138
Liabilities incurred	13,015	5,547
Liability settlements and disposals	(27,036)	(47,842)
Accretion expense	7,583	7,871
Revisions of estimated liabilities	25,420	3,312
Asset retirement obligation at December 31,	173,008	154,026
Less current obligation	13,216	27,058
Long-term asset retirement obligation	$ 159,792	$ 126,968

During 2014, the liability settlements and disposals included $11.2 million related to properties that were sold. Also during this period we recognized revisions of estimated liabilities totaling $25.4 million, which were due to changes in abandonment cost and timing estimates. During 2013, the liability settlements and disposals included $4.4 million related to properties that were sold.

10. 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. The components of the provision for income taxes are as follows:

	Years Ended December 31,		
(in thousands)	2014	2013	2012
Current Taxes:			
Federal (benefit)	$ —	$ (381)	$ (1,629)
State (benefit)	404	(308)	140
	404	(689)	(1,489)

Deferred taxes:			
Federal	282,729	315,165	199,459
State	15,564	14,535	8,757
	298,293	329,700	208,216
	$ 298,697	$ 329,011	$ 206,727

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

	Years Ended December 31,		
(in thousands)	2014	2013	2012
Provision at statutory rate	$ 282,066	$ 312,795	$ 196,192
Effect of state taxes	15,826	14,226	8,902
Domestic Production Activities allowance	—	—	567
Other permanent differences	805	1,990	1,066
Income tax expense	$ 298,697	$ 329,011	$ 206,727

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

	December 31,	
(in thousands)	2014	2013
Long-term:		
Assets:		
Stock compensation and other accrued amounts	$ 26,527	$ 24,815
Net operating loss carryforward, net of valuation allowance	218,584	207,282
Credit carryforward	4,068	4,068
	249,179	236,165
Liabilities:		
Property, plant and equipment	(2,003,885)	(1,696,006)
Net, long-term deferred tax liability	(1,754,706)	(1,459,841)
Current:		
Assets:		
Other accrued amounts	13,475	16,854
	13,475	16,854
Net deferred tax liabilities	$ (1,741,231)	$ (1,442,987)

At December 31, 2014, the company had a U.S. net tax operating loss carryforward of approximately $651.1 million, which would expire in years 2031 through 2034. We believe that the carryforward will be utilized before it expires. The company recorded an increase to its net operating loss carryforward at December 31, 2014 for certain state losses. A corresponding valuation allowance of $19.1 million was established since 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 $83.1 million. We also had an alternative minimum tax credit carryforward of approximately $4.1 million.

At December 31, 2014 and 2013, 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 2011 through 2013 remain open to examination by the Internal Revenue Service of the United States. We file tax returns with various state taxing authorities which remain open to examination for the 2010 through 2013 tax years.

11. 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 $14.3 million in 2014. Rent expense was $13.2 million and $5.7 million for 2013 and 2012,

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respectively. The increases in rent expense over the periods were due to additional costs associated with office relocations and entering into new lease arrangements.

Shown below are future minimum cash payments required under these leases as of December 31, 2014.

(in thousands)	Operating Leases
2015	$ 10,166
2016	11,261
2017	10,789
2018	10,416
2019	10,522
Later years	67,795
Total future minimum lease payments	$ 120,949

Other Commitments

We have commitments of $207.7 million to finish drilling and completing wells in progress at December 31, 2014. We also have various commitments for drilling rigs. The total minimum expenditure commitments under these agreements are $51.7 million.

In New Mexico and Texas, we are constructing gathering facilities and pipelines. At December 31, 2014, we had commitments of $6.9 million relating to these construction projects.

At December 31, 2014, we had firm sales contracts to deliver approximately 30.8 Bcf of natural gas over the next 12 months. If this gas is not delivered, our financial commitment would be approximately $91.7 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.

We have other various transportation and delivery commitments in the normal course of business, which are not material individually or in the aggregate.

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

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.

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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 July 31, 2014, the Plaintiffs appealed the trial court's denial of prejudgment interest, which will be determined by the Oklahoma Supreme Court. The outcome of these remaining issues cannot be determined, and our current estimates and assessments likely will change, as a result of these future legal proceedings.

Hitch Enterprises, Inc. et al. v. Cimarex Energy Co.

On December 11, 2012, Cimarex entered into a preliminary resolution of the Hitch Enterprises, Inc., et al. v. Cimarex Energy Co., et al. (Hitch) litigation matter for $16.4 million. Hitch is a statewide royalty class action pending in the Federal District Court in Oklahoma City, Oklahoma. The settlement was reached at a mediation, which occurred after the parties began to exchange information, including damage analyses, on November 16, 2012. On July 2, 2013, the Court entered a judgment approving the parties' settlement. The judgment became final and unappealable on August 2, 2013. Cimarex distributed the settlement proceeds pursuant to the Court's order in September 2013 and the administration of the settlement is ongoing. In the fourth quarter of 2012, we accrued $16.4 million for this matter.

12. RELATED PARTY TRANSACTIONS

Helmerich & Payne, Inc. (H&P) provides contract drilling services to Cimarex. Drilling costs of approximately $18.4 million were incurred by Cimarex related to such services for 2014. During 2013 and 2012, such costs were $17.0 million and $20.8 million, respectively. Hans Helmerich, a director of Cimarex, is Chairman of the Board of Directors of H&P.

Jerry Box, a director of Cimarex, was the non-executive Chairman of the Board of Newpark through May 2014. Certain subsidiaries of Newpark Resources, Inc. have provided various drilling services to Cimarex. Costs of such services were $0.6 million through May 2014. During 2013 and 2012, such costs were $3.5 million and $4.1 million, respectively.

13. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Years Ended December 31,		
(in thousands)	2014	2013	2012
Cash paid during the period for:			
Interest expense (including capitalized amounts)	$ 66,167	$ 50,754	$ 42,420
Interest capitalized	$ 32,623	$ 29,098	$ 30,255
Income taxes	$ 354	$ 205	$ 377

Cash received for income taxes	$ 460	$ 966	$ 49,754

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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 20 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 ten 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, 2014. 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 40 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 are also involved in this estimation process.

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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, 2011	1,216,441	72,322	65,815	2,045,265
Revisions of previous estimates	(211,401)	(3,154)	(4,492)	(257,276)
Extensions and discoveries	372,459	27,817	36,324	757,307
Purchases of reserves	50	14	2	145
Production	(118,495)	(11,516)	(6,952)	(229,299)
Sales of properties	(7,191)	(7,562)	(788)	(57,298)
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
Proved developed reserves:				
December 31, 2011	989,511	68,250	44,755	1,667,541
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
Proved undeveloped reserves:				
December 31, 2011	226,930	4,072	21,060	377,724
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

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 proved undeveloped (PUD) reserves in our Can-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.

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During 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.

During 2013, we had net negative reserve revisions of 216 Bcfe. Approximately 208 Bcfe of the net negative revisions 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.

In 2012, we added 757.3 Bcfe of proved reserves through extensions and discoveries. In our western Oklahoma Cana-Woodford shale area, we added 202.5 Bcfe from infill wells drilled and 315.9 Bcfe of PUD reserves. Development drilling in the Permian Basin added 229.2 Bcfe.

Approximately 72 Bcfe of the 257.3 Bcfe net negative revisions during 2012 related to production performance of certain wells drilled in our Cana-Woodford shale project. The remainder of the net negative revisions primarily resulted from decreases in prices (91 Bcfe), increases in operating expenses (21 Bcfe) which shortened the economic lives, adjustments to previously booked PUD reserves (25 Bcfe) and the removal of PUD locations due to altered future drilling plans (42 Bcfe).

At December 31, 2014, we had PUD reserves of 730 Bcfe, up 228 Bcfe from 502 Bcfe of PUDs at December 31, 2013. Changes in our PUD reserves are summarized in the table below (in Bcfe).

PUD reserves at December 31, 2013	501.7
Converted to developed	(279.7)
Additions	496.6
Acquisitions	1.9
Net revisions	9.8
PUD reserves at December 31, 2014	730.3

During 2014, we invested $503.5 million to develop and convert 56% of our 2013 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 2013, we invested $255.5 million for conversion of PUD reserves to proved developed reserves, converting 56% of our 2012 PUD reserves.

All 497 Bcfe of PUD reserve additions occurred in our western Oklahoma, Cana-Woodford shale play. Roughly 88% 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.

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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, 2014	2013	2012
Costs incurred during the year:			
Acquisition of properties			
Proved	$ 138,508	$ 682	$ 2,645
Unproved	277,099	195,121	117,695
Exploration	50,271	52,672	109,169
Development	1,664,877	1,354,098	1,426,918
Oil and gas expenditures	2,130,755	1,602,573	1,656,427
Property sales	(446,107)	(61,503)	(305,862)
	1,684,648	1,541,070	1,350,565
Asset retirement obligation, net	27,243	4,426	12,525
	$ 1,711,891	$ 1,545,496	$ 1,363,090

Aggregate Capitalized Costs—The table below reflects the aggregate capitalized costs relating to our oil and gas producing activities at December 31, 2014.

(in thousands)	
Proved properties	$ 14,402,064
Unproved properties and properties under development, not being amortized	759,149
	15,161,213
Less-accumulated depreciation, depletion and amortization	(8,257,502)
Net oil and gas properties	$ 6,903,711

Costs Not Being Amortized—The following table summarizes oil and gas property costs not being amortized at December 31, 2014, by year that the costs were incurred.

(in thousands)		
2014	$	428,551
2013		158,038
2012		33,428
2011 and prior		139,132
	$	759,149

Of the costs not being amortized, $172.5 million (23%) relates to unevaluated wells in progress and $61.2 million (8%) is capitalized interest. The remaining $525.4 million is for land and seismic expenditures, most of which were for costs invested in our Cana-Woodford shale project ($251.0 million) and our Permian Basin region ($208.9 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 over the next five years.

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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)	2014	2013	2012
Oil, gas and NGL revenues from production	$ 2,372,829	$ 1,952,505	$ 1,581,650
Less operating costs and income taxes:			
Depletion	773,817	584,628	484,529
Asset retirement obligation	10,082	7,989	13,019
Production	342,304	286,742	258,584
Transportation, processing and other operating	195,414	93,580	57,354
Taxes other than income	128,793	112,732	86,994
Income tax expense	341,848	319,082	251,215
	1,792,258	1,404,753	1,151,695
Results of operations from oil and gas producing activities	$ 580,571	$ 547,752	$ 429,955
Depletion rate per Mcfe	$ 2.44	$ 2.31	$ 2.11

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, a discount factor more representative of the time value of money, 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)	2014	2013	2012
Cash inflows	$ 19,892,471	$ 16,565,980	$ 12,384,251
Production costs	(5,777,710)	(5,000,004)	(3,684,875)
Development costs	(1,453,860)	(1,113,743)	(562,994)
Income tax expense	(3,768,780)	(3,099,304)	(2,368,115)
Net cash flow	8,892,121	7,352,929	5,768,267
10% annual discount rate	(4,539,276)	(3,754,035)	(2,859,566)
Standardized measure of discounted future net cash flow	$ 4,352,845	$ 3,598,894	$ 2,908,701

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. If future gas sales are covered by contracts at specified prices, the contract prices would be used. Fluctuations in prices are due to supply and demand and are beyond our control.

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The following average prices were used in determining the Standardized Measure as of:

	December 31, 2014	2013	2012
Gas price per Mcf	$ 3.61	$ 3.01	$ 2.27
Oil price per Bbl	$ 86.85	$ 92.74	$ 88.91
NGL price per Bbl	$ 28.23	$ 28.42	$ 29.12

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

(in thousands)	December 31, 2014	2013	2012
Standardized Measure, beginning of period	$ 3,598,894	$ 2,908,701	$ 3,139,750
Sales, net of production costs	(1,706,318)	(1,459,451)	(1,178,718)
Net change in sales prices, net of production costs	(166,746)	371,563	(957,606)
Extensions and discoveries, net of future production and development costs	1,633,285	1,901,786	1,707,024
Changes in future development costs	23,025	121,347	146,808
Previously estimated development costs incurred during the period	442,780	253,047	148,976
Revision of quantity estimates	230,673	(436,856)	(457,013)
Accretion of discount	520,058	416,594	459,490
Change in income taxes	(434,949)	(344,447)	197,916
Purchases of reserves in place	228,539	1,552	572
Sales of properties	(185,326)	(38,080)	(214,746)
Change in production rates and other	168,930	(96,862)	(83,752)
Standardized Measure, end of period	$ 4,352,845	$ 3,598,894	$ 2,908,701

SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED)

2014	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

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2013	First	Second	Third	Fourth
(in thousands, except for per share data)				
Revenues	$ 426,356	$ 493,757	$ 561,336	$ 516,602
Expenses, net	336,429	364,192	422,966	309,775
Net income	$ 89,927	$ 129,565	$ 138,370	$ 206,827
Earnings per share to common stockholders:				
Basic:				
Distributed	$ 0.14	$ 0.14	$ 0.14	$ 0.14
Undistributed	0.90	1.36	1.45	2.23
	$ 1.04	$ 1.50	$ 1.59	$ 2.37
Diluted:				
Distributed	$ 0.14	$ 0.14	$ 0.14	$ 0.14
Undistributed	0.90	1.35	1.45	2.23
	$ 1.04	$ 1.49	$ 1.59	$ 2.37

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, 2014. Based on that evaluation, the CEO and CFO concluded that the disclosure controls and procedures are effective in providing reasonable assurance that information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow such persons to make timely decisions regarding required disclosures.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in our internal control over financial reporting that occurred during 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, 2014, 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, 2014.

Our independent registered public accounting firm has audited, and reported on, the effectiveness of our internal controls over financial reporting as of December 31, 2014, which follows this report.

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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, 2014, 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, 2014, 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, 2014 and 2013, and the related consolidated statements of income and comprehensive income, stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 25, 2015 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Denver, Colorado

February 25, 2015

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ITEM 9B. OTHER INFORMATION

None.

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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 14, 2015 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, 2014. The executive officers of Cimarex as of February 25, 2015 were:

Name	Age	Office
Thomas E. Jorden	57	Chief Executive Officer, President and Chairman of the Board
Joseph R. Albi	56	Executive Vice President – Operations, Chief Operating Officer
Stephen P. Bell	60	Executive Vice President – Business Development
Paul Korus	58	Senior Vice President – Chief Financial Officer
Francis B. Barron	52	Senior Vice President – General Counsel
Gary R. Abbott	42	Vice President, Corporate Engineering
Richard S. Dinkins	70	Vice President – Human Resources
John Lambuth	52	Vice President – Exploration
James H. Shonsey	63	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.

PAUL KORUS was named senior vice president in December 2010 and has served as chief financial officer of Cimarex since September 2002. From June 1999 to September 2002, Mr. Korus was vice president and chief financial officer of Key Production Company. Prior to Key, he was an equity research analyst with an energy investment banking firm from 1995 to 1999 and was with Apache Corporation from 1982 to 1995.

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 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

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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.

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.

JOHN LAMBUTH was named vice president of exploration in September 2012. Prior to his promotion, he served as the company's 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.

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 14, 2015 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, 2014.

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 14, 2015 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, 2014.

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 14, 2015 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, 2014.

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 14, 2015 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, 2014.

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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).
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.

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).

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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).
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 (filed as Exhibit 21.1 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).
23.1	Consent of KPMG LLP (filed as Exhibit 23.1 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).
23.2	Consent of DeGolyer and MacNaughton (filed as Exhibit 23.2 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).
24.1	Power of Attorney of directors of the Registrant (filed as Exhibit 24.1 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).
31.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32.1	Certification of Thomas E. Jorden, Chief Executive Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed as Exhibit 32.1 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).
32.2	Certification of Paul Korus, Chief Financial Officer of Cimarex Energy Co., pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed as Exhibit 32.2 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).
99.1	Letter dated January 16, 2015 from DeGolyer and MacNaughton, independent petroleum engineering consulting firm, reporting the results of its audit of Cimarex reserves as of December 31, 2014 of certain selected properties (filed as Exhibit 99.1 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).

101.INS	XBRL Instance Document. *
101.SCH	XBRL Taxonomy Extension Schema Document. *
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document. *

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101.LAB	XBRL Taxonomy Extension Label Linkbase Document. *
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document. *
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document. *

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SIGNATURE

Pursuant to the requirements of 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: March 9, 2015

CIMAREX ENERGY CO.

By: /s/ Thomas E. Jorden
Thomas E. Jorden
Chairman, President & Chief Executive Officer