CIMAREX ENERGY CO
Form 10-K
February 20, 2019
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)

ý	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018
OR

o	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)
(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 ý NO o
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 o NO ý
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 ý NO o
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). YES ý NO o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO ý

Aggregate market value of the voting stock held by non-affiliates of Cimarex Energy Co. as of June 30, 2018 was approximately $9.54 billion.

Number of shares of Cimarex Energy Co. common stock outstanding as of January 31, 2019 was 95,755,298.

Documents Incorporated by Reference: Portions of the Registrant's Proxy Statement for its 2019 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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DESCRIPTION

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GLOSSARY

Bbls—Barrels (of oil or natural gas liquids)
Bcf—Billion cubic feet (of natural gas)
BOE—Barrels of oil equivalent
GAAP—Generally accepted accounting principles in the U.S.
Gross Acres or Gross Wells—The total acres or wells, as the case may be, in which a working interest is owned.
MBbls—Thousand barrels
MBOE—Thousand barrels of oil equivalent
Mcf—Thousand cubic feet
MMBbls—Million barrels
MMBtu—Million British thermal units
MMBOE—Million barrels of oil equivalent
MMcf—Million cubic feet
Net Acres or Net Wells—The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers and fractions of whole numbers.
Net Production—Gross production multiplied by net revenue interest
NGL or NGLs—Natural gas liquids
PUD—Proved undeveloped
Tcf—Trillion cubic feet

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

CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS

Throughout this Form 10-K, we make statements that may be deemed “forward-looking” statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. In particular, in our Management’s Discussion and Analysis of Financial Condition and Results of Operations, we provide projections of our 2019 capital expenditures. 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, gas, and NGL production, including local market price differentials;
- Operating costs and other expenses;
- Timing and amount of future production of oil, gas, and NGLs;
- Reductions in the quantity of oil, gas, and NGLs sold and prices received due to decreased industrywide demand and/or curtailments in production from specific properties or areas due to mechanical, transportation, marketing, weather, or other problems;
- Estimates of proved reserves, exploitation potential, or exploration prospect size;
- Our ability to complete our pending acquisition of Resolute Energy Corporation (“Resolute”) and to successfully integrate the business of Resolute;
- Our hedging activities and viability of hedge counterparties;
- The effectiveness of our internal control over financial reporting;
- Cash flow and anticipated liquidity;
- Amount, nature, and timing of capital expenditures;
- Availability of financing and access to capital markets;
- Administrative, legislative, and regulatory changes;
- 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;
- Increased financing costs due to a significant increase in interest rates;
- Proving up undeveloped acreage; and
- Full cost ceiling test impairments to the carrying values of our oil and gas properties.

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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, gas, and NGLs.

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, production type curves, well spacing, 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.

Risk factors related to our pending acquisition of Resolute include, among others: the expected timing and likelihood of completion of the proposed transaction, the ability to successfully integrate the businesses, the occurrence of any event, change, or other circumstances that could give rise to the termination of the merger agreement, the possibility that stockholders of Resolute may not approve the merger agreement, the risk that the parties may not be able to satisfy the conditions to the proposed transaction in a timely manner or at all, risks related to disruption of management time from ongoing business operations due to the proposed transaction, the risk that any announcements relating to the proposed transaction could have adverse effects on the market price of Cimarex’s common stock or Resolute’s common stock, the risk of any unexpected costs or expenses resulting from the proposed transaction, the outcome of any litigation relating to the proposed transaction, the risk that the proposed transaction and its announcement could have an adverse effect on the ability of Cimarex and Resolute to retain customers and retain and hire key personnel and maintain relationships with their suppliers and customers and on their operating results and businesses generally, the risk the pending proposed transaction could distract management of both entities and they will incur substantial fees and costs, the risk that problems may arise in successfully integrating the businesses of the companies, which may result in the combined company not operating as effectively and efficiently as expected, the risk that the combined company may be unable to achieve synergies or other anticipated benefits of the proposed transaction or it may take longer than expected to achieve those synergies or benefits and other important factors, such as expenses related to integration, that could cause actual results to differ materially from those projected. The acquisition is subject to an agreement and plan of merger entered into November 18, 2018 among the parties.

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, which we make available free of charge. Information contained on our website is not incorporated by reference into this Annual Report. Throughout this Form 10-K we use the terms "Cimarex," "company," "we," "our," and "us" to refer to Cimarex Energy Co. and its subsidiaries.

Our principal business objective is to increase shareholder value through the profitable long-term growth of our proved reserves and production while seeking to minimize our impact on the communities in which we operate for the long-term. Our strategy centers on maximizing cash flow from producing properties so that we can reinvest in exploration and development opportunities and provide cash returns to shareholders through increasing dividends. We consider merger and acquisition opportunities that enhance our competitive position and we occasionally divest non-core assets. Key elements to our approach include:

- Maintain a strong financial position;
- Invest in a diversified portfolio of drilling opportunities;
- Evaluate projects based on rate-of-return and rank investment decisions;
- Track predicted versus actual results in a centralized exploration management system to provide feedback to improve results;
- Attract quality employees and maintain integrated teams of geoscientists, landmen, and engineers; and
- Maximize profitability.

Conservative use of leverage has long been the key to our financial strategy. We believe that low leverage coupled with strong full-cycle returns enables us to better withstand volatility in commodity prices and provide competitive returns and growth to shareholders. See Item 5 Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities — Stock Performance Graph and Item 6 Selected Financial Data for additional financial and operating information for fiscal years 2014 - 2018.

Proved Oil and Gas Reserves

Our December 31, 2018 total proved reserves grew 6% from prior year-end. Proved undeveloped reserves as a percentage of total proved reserves decreased to 15% from 17% a year ago. We added 158.5 MMBOE of new reserves through extensions and discoveries. Net negative revisions totaled 22.7 MMBOE, which consisted primarily of a decrease of 38.6 MMBOE for the removal of PUD reserves whose development will likely be delayed beyond five years of initial disclosure, partially offset by an increase of 20.9 MMBOE for technical revisions. The change in our proved reserves is as follows:

	Proved Reserves (MBOE)
Reserves at December 31, 2017	559,037
Revisions of previous estimates	(22,667)
Extensions and discoveries	158,512
Purchases of reserves	1
Production	(81,010)
Sales of reserves	(22,678)

Reserves at December 31, 2018	591,195

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

	December 31,		
	2018	2017	2016
Proved reserves:			
Gas (MMcf)	1,591,321	1,607,635	1,471,420
Oil (MBbls)	146,538	137,238	105,878
NGL (MBbls)	179,436	153,860	130,633
Total (MBOE)	591,195	559,037	481,748
Percent developed	85 %	83 %	79 %

The following table summarizes our estimated proved oil and gas reserves by region as of December 31, 2018.

	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)	% of Total Proved Reserves
Mid-Continent	861,440	29,908	82,826	256,307	43 %
Permian Basin	727,985	116,378	96,533	334,241	57 %
Other	1,896	252	77	647	— %
	1,591,321	146,538	179,436	591,195	100 %

See SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED) in Item 8 for further information regarding our reserves.

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Production Volumes, Prices, and Costs

All of our oil and gas assets are located in the United States. We have varying levels of ownership interests in our properties consisting of working, royalty, and overriding royalty interests. Operated wells account for approximately 83% of our proved reserves.

Our 2018 production volumes totaled 221.9 MBOE per day, a 17% increase from 2017, and were comprised of 42% gas, 31% oil, and 27% NGLs. The following table presents our total and average daily production volumes by region.

	Total Production Volumes				Average Daily Production Volumes			
Years Ended December 31,	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)
2018								
Permian Basin	92,593	19,104	11,499	46,035	253.7	52.3	31.5	126.1
Mid-Continent	112,697	5,530	10,474	34,787	308.8	15.2	28.7	95.3
Other	547	76	21	188	1.4	0.2	0.1	0.5
Total company	205,837	24,710	21,994	81,010	563.9	67.7	60.3	221.9
2017								
Permian Basin	79,521	16,271	8,858	38,382	217.9	44.6	24.3	105.2
Mid-Continent	107,463	4,547	8,503	30,960	294.4	12.5	23.3	84.8
Other	484	43	13	137	1.3	0.1	—	0.4
Total company	187,468	20,861	17,374	69,479	513.6	57.2	47.6	190.4
2016								
Permian Basin	65,191	13,183	6,677	30,725	178.1	36.0	18.2	83.9
Mid-Continent	102,501	3,283	7,508	27,874	280.1	9.0	20.5	76.2
Other	535	62	15	166	1.4	0.2	0.1	0.5
Total company	168,227	16,528	14,200	58,765	459.6	45.2	38.8	160.6

At December 31, 2018, we had two fields that contained 15% or more of our total proved reserves. These fields are the Watonga-Chickasha in the Cana area of the Mid-Continent, which contained approximately 39% of our total proved reserves, and the Ford West in the Permian Basin, which contained approximately 16% of our total proved reserves. At December 31, 2017 and 2016, the Watonga-Chickasha was our only field that contained 15% or more of our total proved reserves. Production for these fields is presented in the following table.

	Total Production Volumes				Average Daily Production Volumes			
Years Ended December 31,	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)
2018								
Watonga-Chickasha	96,373	5,094	9,774	30,930	264.0	14.0	26.8	84.7
Ford West	30,958	3,748	3,804	12,711	84.8	10.3	10.4	34.8
2017								
Watonga-Chickasha	88,557	4,156	7,829	26,744	242.6	11.4	21.4	73.3
Ford West	26,405	3,370	2,883	10,654	72.3	9.2	7.9	29.2
2016								

Watonga-Chickasha	81,757	2,823	6,764	23,213	223.4	7.7	18.5	63.4
Ford West	20,034	2,258	1,927	7,525	54.7	6.2	5.3	20.6

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The following table presents the average commodity prices received and production cost per unit of production by region.

Years Ended December 31,	Average Realized Price Gas (per Mcf)	Oil (per Bbl)	NGL (per Bbl)	Production Cost (per BOE)
2018				
Permian Basin	$1.69	$54.95	$22.84	$ 4.30
Mid-Continent	$2.23	$62.31	$21.67	$ 2.69
Other	$2.97	$58.40	$26.46	$ 7.63
Total Company	$1.99	$56.61	$22.28	$ 3.62
2017				
Permian Basin	$2.72	$46.96	$20.25	$ 4.70
Mid-Continent	$2.78	$47.42	$23.02	$ 2.60
Other	$2.74	$46.53	$23.11	$ 9.03
Total Company	$2.76	$47.06	$21.61	$ 3.77
2016				
Permian Basin	$2.35	$38.45	$12.32	$ 5.16
Mid-Continent	$2.29	$37.65	$15.59	$ 2.57
Other	$2.00	$38.86	$14.80	$ 9.56
Total Company	$2.31	$38.30	$14.05	$ 3.95

Acquisitions and Divestitures

We consider property acquisitions, divestitures, and occasional mergers to enhance our competitive position. Moreover, sales of non-core assets are a source of liquidity that we can use to supplement funding of capital expenditures and acquisitions of core assets.

In 2018, we sold interests in various non-core oil and gas properties for cash proceeds totaling $581 million. Included in these divestitures was a sale of oil and gas properties principally located in Ward County, Texas for which we have received, as of December 31, 2018, $534.6 million in net cash proceeds. Final settlement, which will reflect customary post-closing adjustments, is scheduled to occur by the end of first quarter 2019.

In 2018, we made various oil and gas property acquisitions for $26 million. Additionally, we entered into an agreement and plan of merger to acquire Resolute in a cash and stock transaction valued at a total purchase price of approximately $1.6 billion, including cash, stock, and the assumption of Resolute's long-term debt. This pending acquisition will expand our footprint in Reeves County, Texas by 21,100 net acres that are complementary to our existing Reeves County position. The transaction, which is expected to be completed by the end of the first quarter 2019, is subject to the approval of Resolute shareholders and the satisfaction of certain regulatory approvals and other customary closing conditions.

Exploration and Development 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.

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A summary of our 2018 exploration and development activity by region is as follows:

	E&D Capital	Gross Wells Completed	Net Wells Completed	% Completed As Producers	
	(in millions)				
Permian Basin	$ 1,092	129	79.9	100	%
Mid-Continent	472	220	42.2	100	%
Other	6	—	—	—	%
	$ 1,570	349	122.1	100	%

The Permian Basin 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 2018, we focused on drilling horizontal wells that yielded oil and liquids-rich gas from the Wolfcamp shale and the Bone Spring formation. Cimarex saw improved results in its Wolfcamp shale wells, as measured by production and reserves, with the further implementation of long laterals and continued improvement in well completion design and in the Bone Spring wells via larger well completions.

The Permian Basin produced 126.1 MBOE per day in 2018, which was 57% of our total company production. Total production from the region increased 20% in 2018 over 2017. In 2018, we invested $1.09 billion, or 70% of our total E&D investment, in the Permian Basin.

Our Mid-Continent region consists of Oklahoma and the Texas Panhandle. Our activity in 2018 in the Mid-Continent was focused in the Woodford shale and the Meramec horizon, both in Oklahoma. We continued to refine well completions and spacing in the Woodford shale and the Meramec horizon.

During 2018, production from the Mid-Continent averaged 95.3 MBOE per day, or 43% of total company production. Total production from the region increased 12% in 2018 over 2017. In 2018, we invested $472 million, or 30% of our total E&D investment, in the Mid-Continent.

Drilling Activity

In 2018, we completed or participated in the completion of 349 gross (122.1 net) wells, of which we operated 146 gross (105.8 net) wells. At year-end, we were in the process of drilling or participating in 40 gross (12.6 net) wells and there were 83 gross (28.3 net) wells waiting on completion.

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We completed the following number of developmental wells in the years indicated in the table below. During these years, we completed no exploratory wells.

	Wells Completed					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Developmental						
Productive	349	122.1	314	96.4	153	61.0
Dry	—	—	5	1.6	1	—
Total	349	122.1	319	98.0	154	61.0

At December 31, 2018, we owned an interest in 10,362 gross (2,902 net) productive oil and gas wells. We had working interests in the following number of productive wells by region as of December 31, 2018:

	Gas		Oil	
	Gross	Net	Gross	Net
Mid-Continent	3,992	1,513	791	197
Permian Basin	769	342	4,702	842
Other	93	6	15	2
	4,854	1,861	5,508	1,041

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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, 2018. 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	97,203	65,250	687,246	305,702	784,449	370,952
Texas	17,975	12,302	128,956	54,255	146,931	66,557
	133,409	95,743	816,202	359,957	949,611	455,700
Permian Basin						
New Mexico	74,227	54,657	175,974	119,892	250,201	174,549
Texas	69,566	50,852	182,717	121,933	252,283	172,785
	143,793	105,509	358,691	241,825	502,484	347,334
Other						
Arizona	2,097,841	2,097,841	17,207	—	2,115,048	2,097,841
California	383,487	383,487	—	—	383,487	383,487
Colorado	40,232	18,867	41,384	1,642	81,616	20,509
Gulf of Mexico	25,000	13,000	28,848	6,381	53,848	19,381
Louisiana	132,842	129,792	2,868	168	135,710	129,960
Michigan	234	156	587	587	821	743
Montana	30,755	7,687	7,688	1,721	38,443	9,408
Nevada	1,007,167	1,007,167	440	1	1,007,607	1,007,168
New Mexico	1,641,126	1,633,819	18,331	2,436	1,659,457	1,636,255
Texas	8,888	2,696	23,549	4,784	32,437	7,480
Utah	80,527	59,433	31,912	1,495	112,439	60,928
Wyoming	96,454	13,944	41,629	3,829	138,083	17,773
Other	168,034	145,680	9,627	3,351	177,661	149,031
	5,712,587	5,513,569	224,070	26,395	5,936,657	5,539,964
Total	5,989,789	5,714,821	1,398,963	628,177	7,388,752	6,342,998

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									
	2019		2020		2021		2022		2023	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	1,940	1,543	10,942	10,923	6,682	6,682	1,848	1,848	284	284
Permian Basin	15,224	15,224	10,154	10,154	4,290	4,290	2,148	2,148	960	960
Other	180,509	176,413	34,934	34,901	10,706	10,626	31,961	30,940	7,105	6,963
	197,673	193,180	56,030	55,978	21,678	21,598	35,957	34,936	8,349	8,207
% of undeveloped acreage	3.3	3.4	0.9	1.0	0.4	0.4	0.6	0.6	0.1	0.1

At December 31, 2018, we had no proved undeveloped reserves scheduled for development beyond the expiration dates of our undeveloped acreage.

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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 NGLs at prices tied to monthly index prices where we deliver our NGLs.

We sell our oil, gas, and NGLs to a broad portfolio of customers, including major energy companies, pipeline companies, local distribution companies, and other end-users. In 2018, we made sales to two customers that each amounted to 10% or more of our consolidated revenues for 2018. Sales to those two customers accounted for 23% and 21%, respectively, of our consolidated revenues for 2018. If any one of our major customers 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 multiple significant customers were to discontinue purchasing our production, we believe there would be challenges initially, but ample markets to handle the disruption.

We regularly monitor the credit worthiness of all our customers and may require parent company guarantees, letters of credit, or prepayments when deemed necessary. Historically, losses associated with uncollectible receivables have not been significant.

Corporate Headquarters and Employees

Our corporate headquarters is located at 1700 Lincoln St., Suite 3700, Denver, Colorado 80203. On December 31, 2018 and 2017, Cimarex had 955 and 910 employees, respectively. None of our employees are subject to collective bargaining agreements.

Competition

The oil and gas industry is highly competitive, particularly for prospective undeveloped leases and purchases of proved reserves. There is also competition for rigs and related equipment used to drill for and produce oil and gas, however, to a lesser extent in the current market environment. Our competitive position also is 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, gas, and NGLs 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 Rule 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.

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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, performed an independent evaluation of our estimated net reserves representing greater than 80% of the total future net revenue discounted at 10% attributable to the total interests owned by Cimarex as of December 31, 2018. 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 34 years of experience in oil and gas reservoir studies and reserves 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 24 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 14 years.

Title to Oil and Gas Properties

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

Government Regulation

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

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

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

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

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

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

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

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

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

Federal and State Income and Other Local Taxation

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

Executive Officers of the Registrant

See Part III, Item 10, Directors, Executive Officers and Corporate Governance for information regarding our executive officers as of February 20, 2019.

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, financial condition, and results of operations, which in turn could negatively impact the value of our securities.

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Risks Concerning Cimarex and its Operations

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

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

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

If prices decrease, we may 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.

In 2016 we recognized a ceiling test impairment totaling $757.7 million ($481.4 million, net of tax). The impairment resulted primarily from the impact of decreases in the trailing twelve-month average prices for oil, gas, and NGLs utilized in determining the estimated future net cash flows from proved reserves. We did not recognize any ceiling test impairments in 2017 or 2018 since the calculated value of the ceiling limitation exceeded the carrying value of our oil and gas properties subject to the test. At December 31, 2018, a decline of approximately 24% or more in the value of the ceiling limitation would have resulted in an impairment. Because the ceiling calculation uses trailing twelve-month average commodity prices, the effect of increases and decreases in period-over-period prices can significantly impact the ceiling limitation calculation. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet.

We evaluate our goodwill for impairment annually and whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. We have had no goodwill impairments during the years ended December 31, 2018, 2017, and 2016.
Ineffective internal controls could impact our business and financial results.

Our internal control over financial reporting may not prevent or detect misstatements because of its inherent limitations, including the possibility of human error, the circumvention or overriding of controls, or fraud. Even effective internal controls can provide only reasonable assurance with respect to the preparation and fair presentation of financial statements. If we fail to maintain the adequacy of our internal controls, including any failure to implement required new or improved controls, or if we experience difficulties in their implementation, our business and financial results could be harmed and we could fail to meet our financial reporting obligations. For example, at December 31, 2016, management concluded that a deficiency in the design of our internal controls related to the full cost ceiling test calculation represented a material weakness in our internal control over financial reporting and, therefore, that we did not maintain effective internal control over financial reporting as of December 31, 2016, as reported in our Form 10-K/A for that period. We have since remediated this material weakness, however, there is no guarantee that we won’t experience material weaknesses in our internal control over financial reporting in the future or that we will be able to implement new controls to address such material weaknesses as necessary, which may result in untimely or inaccurate reporting of our financial statements.

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

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

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

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

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

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

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

Estimates of total proved oil and gas reserves (consisting of proved developed and proved undeveloped reserves) and associated future net cash flow depend on a number of variables and assumptions. Refer to CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS in Part I of this report. Among others, changes in any of the following factors may cause actual results to vary considerably from our estimates:

- oil, gas, and NGL prices;
- 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;
- governmental regulation;
- access to assets restricted by local government action;
- operating costs;
- property, severance, excise, and other taxes incidental to oil and gas operations;

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- workover and remediation costs; and
- federal and state income taxes.

Our proved oil and gas reserve estimates are prepared by Cimarex engineers in accordance with guidelines established by the SEC. DeGolyer and MacNaughton, independent petroleum engineers, performed an independent evaluation of our estimated net reserves representing greater than 80% of the total future net revenue discounted at 10%, as of December 31, 2018.

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 twelve 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.

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 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 inability to transport one commodity, such as gas, could also impair our ability to produce and sell other commodities, such as oil and NGLs, produced from the same wells. 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 with less established infrastructure, such as our Delaware Basin area where we and competitors have significant development activities. The lack of availability of or capacity in these facilities or the loss of these facilities due to construction delays, 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, gas, and NGLs. 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 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.

Commodity price derivative transactions may limit our potential gains and involve other risks.

To limit our exposure to price risk, we enter into derivative agreements from time to time. Commodity price derivatives 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 derivatives.

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

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

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

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

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

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

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

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

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 and the inability to attract employees to those areas, as well as the vendors' ability to deploy their resources in easier-to-access areas.

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

Exploration, production, and the sale of oil and gas are subject to extensive laws and regulations, including those implemented to protect the environment, human health and safety, and wildlife. Federal, state, and local regulatory agencies frequently require permitting and impose conditions on our activities. During the permitting process, these regulatory agencies often exercise considerable discretion in both the timing and scope of the permits, and the public, including special interest groups, often has an opportunity to influence the timing and outcome of the process. The requirements or conditions imposed by these agencies can be costly and can delay the commencement of our operations. In addition, a number of initiatives were put forth by the Obama administration in the form of Presidential or Secretarial Memoranda, which are still in effect, and have the potential to impact the cost of doing business or could result in substantial delays in permitting, drilling, and other oil and gas activities.

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

Environmental matters and costs can be significant.

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

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

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

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

- The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as CERCLA or the Superfund law, and comparable state laws, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- The Oil Pollution Act of 1990 (“OPA”), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are

liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States;

- The Resource Conservation and Recovery Act (“RCRA”), as amended, and comparable state statutes, which governs the treatment, storage, and disposal of solid waste;
- The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act (“CWA”), which governs the discharge of pollutants, including natural gas wastes, into federal and state waters;

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- 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, OPA, RCRA, CWA, SDWA, CAA and related state and local laws and regulations. We also believe we hold all necessary and up-to-date permits, registrations, and other authorizations required under such laws and regulations. Although the current costs of managing our wastes as they presently are classified are reflected in our budget, any legislative or regulatory reclassification of oil and 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 gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on federal oil and gas leases in areas where certain species are currently listed as threatened or endangered, or could be listed as such, under the ESA. Operations in areas where threatened or endangered species or their habitat are known to exist may require us to incur increased costs to implement mitigation or protective measures and also may restrict or preclude our drilling activities in those areas or during certain seasons, such as breeding and nesting seasons. On March 27, 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas, New Mexico, and Oklahoma, where we conduct operations, as a threatened species under the ESA. Listing of the lesser prairie chicken as a threatened species imposes restrictions on disturbances to critical habitat by landowners and drilling companies that would harass, harm, or otherwise result in a "taking" of this species. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies ("WAFWA"), pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. We entered into a voluntary Candidate Conservation Agreement ("CCA") with the WAFWA, whereby we agreed to take certain actions and limit certain activities, such as limiting drilling on certain portions of our acreage during nesting seasons, in an effort to protect the lesser prairie chicken. On February 9, 2018, the FWS announced the listing of the Texas Hornshell, a fresh water mussel species in areas including New Mexico and Texas where we operate in the Permian Basin, as an endangered species. We also intend to enter into a CCA concerning voluntary conservation actions with respect to the Texas Hornshell. Participating in CCAs could result in increased costs to us from species protection measures, time delays or limitations on drilling activities, which costs, delays or limitations may be significant. While a federal judge in Texas vacated the listing of the lesser prairie chicken in 2015, listing petitions continue to be filed with the FWS which could impact our operations. Many non-governmental organizations ("NGOs") work closely with the FWS regarding the listing of many species, including species with broad and even nationwide ranges. The recent listing of the Mexican Long Nosed bat, whose habitat includes the Permian Basin where we operate, is an example of the NGOs' influence on ESA listing decisions. The increase in endangered species listings may impact our ability to explore for or produce oil and gas in certain areas and increase our costs.

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

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

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While hydraulic fracturing historically has been regulated by state oil and gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation from federal agencies. For example, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities under the SDWA involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Although the EPA has delegated the permitting authority for the SDWA's Underground Injection Control Class II programs in Oklahoma, Texas, and New Mexico where we maintain operational acreage, the EPA is encouraging state programs to review and consider the use of such draft guidance.

In addition, on March 26, 2015, the federal BLM published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, development of appropriate plans for managing flowback water that returns to the surface, increased standards for interim storage of recovered waste fluids, and submission to the BLM of detailed information on the geology, depth, and location of preexisting wells. This rule originally was scheduled to take effect on June 24, 2015. However, the rule is the subject of several pending lawsuits filed by industry groups, two Indian tribes, and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. The federal judge has enjoined the rule while the case is pending. The district court held that BLM did not have jurisdiction to promulgate the rule. The Obama Justice Department appealed and that appeal is pending.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA prepared a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA's draft report was released on June 4, 2015. The findings of the report suggest that hydraulic fracturing does not pose a systemic risk to groundwater although there are risks to both groundwater and soils posed by inadequate water handling practices in certain situations. A public comment period on the report was open until August 28, 2015, and a series of public hearings were conducted by the EPA's Scientific Advisory Board ("SAB") throughout the fall of 2015. The EPA issued its final report and has reached two different topline conclusions, although the content of the study itself remains unchanged. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing.

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

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

The adoption of climate change legislation or regulations restricting emission of greenhouse gases, investor pressure concerning climate-related disclosures, and lawsuits could result in increased operating costs and reduced demand for the oil and gas we produce as well as reductions in the availability of capital.

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

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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 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 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 previous administration intended to promulgate proposed climate change rulemaking aimed at reducing GHG emissions by 45% by 2025 compared to 2012 levels. These proposals target both new and existing sources. On January 22, 2016, the Department of the Interior announced its proposed emissions mandate on oil and gas producers who operate on federal and Indian lands. While this rule was finalized in November of 2016, it is currently being challenged by several states and industry.

While we expect new legislation and regulations to increase the cost of business, at this time it is not possible to quantify the impact on our business. Any such future laws and final regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to develop and implement best management practices aimed at reducing GHG emissions, install and maintain emissions control technologies, as well as monitor and report on GHG emissions associated with our operations, which would increase our operating costs, and such requirements also could adversely affect demand for the oil and gas that we produce.

The following is a summary of potential climate-related risks that could adversely affect Cimarex:

Transition Risks. Transition risks are risks related to the transition to a lower-carbon economy and include policy, legal, technology, and market risks.

Policy and Legal Risks. Policy risks include policy actions that attempt to contract actions that contribute to adverse effects of climate change or policy actions that seek to promote adaptation to climate change. Examples include implementing carbon-pricing mechanisms to reduce GHG emissions (which would increase the costs of our doing business), shifting energy use toward lower emission sources (which could lower demand for our oil and gas production, resulting in lower prices and lower revenues), adopting energy-efficiency solutions (which also could lower demand for our oil and gas production, resulting in lower prices and lower revenues), encouraging greater water efficiency measures (which would increase our costs of production), and promoting more sustainable land-use practices (which also would increase our costs of production and could impact our ability to operate in certain areas). Policy actions also may include restrictions or bans on oil and gas activities, which could lead to write-downs or impairments of our assets. Legal and litigation risks include potential lawsuits claiming failure to mitigate impacts of climate change, failure to adapt to climate change, and the insufficiency of disclosure around material financial risks.

Technology Risk. Technological improvements or innovations that support the transition to a lower-carbon, more energy efficient economic system may have a significant impact on Cimarex. The development and use of emerging technologies such as renewable energy, battery storage, and energy efficiency may lower demand for oil and gas, resulting in lower prices and revenues, and increase our costs.

Market Risk. Markets could be affected by climate change through shifts in supply and demand for certain commodities, especially carbon-intensive commodities such as oil and gas and other products dependent on oil and gas, as climate-related risks and opportunities are increasingly taken into account. This could lower demand for our oil and gas production, resulting in lower prices and lower revenues. Market risk also may take the form of limited access to capital as investors shift investments to less carbon-intensive industries and alternative energy industries. In addition, there have also been efforts in recent years to influence the investment community, including investment advisers and certain sovereign wealth, pension, and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental

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activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations, and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that GHG emissions from oil, NGL, and gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages, or other liabilities. While we are currently not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Reputation Risk. Climate change has been identified as a potential source of reputational risk tied to changing customer or community perceptions of an organization's contribution to or detraction from the transition to a lower-carbon economy. This could lower demand for our oil and gas production, resulting in lower prices and lower revenues as consumers avoid carbon-intensive industries. This may also put pressure on investment managers to shift investments to less carbon-intensive industries and alternative energy industries, limiting our access to capital.

Physical Risks. Potential physical risks resulting from climate change may be event driven (including increased severity of extreme weather events, such as hurricanes or floods) or longer-term shifts in climate patterns that may cause sea level rise or chronic heat waves. Potential physical risks may cause direct damage to assets and indirect impacts such as supply chain disruption. Potential physical risks also include changes in water availability, sourcing, and quality, which could impact drilling and completions operations. These physical risks could cause increased costs, production disruptions, and lower revenues.

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

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

There exists a growing concern that hydraulic fracturing during well completion operations and the injection of produced water into underground disposal wells triggers seismic activity in certain areas, including Oklahoma and Texas, where we operate. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in connection with hydraulic fracturing and in the permitting of saltwater disposal wells or otherwise to assess any relationship between seismicity and these oil and gas operations. For example, in 2014, the Oklahoma Corporation Commission began adopting rules for operators of saltwater disposal wells in certain seismically-active areas, or Areas of Interest, in the Arbuckle formation, requiring operators to monitor and record well pressure and discharge volume on a daily basis and further requiring operators of wells permitted for disposal of 20,000 barrels per day or more of saltwater to conduct mechanical integrity testing. Throughout 2015 and 2016, the Oklahoma Corporation Commission's Oil and Gas Conservation Division, or OGCD, issued a series of directives, expanding the areas of interest for induced seismicity and enhanced disposal restrictions and limiting the depths at which produced water could be injected or, in the alternative, reducing disposal volumes. Additional regulations and restrictions are possible as more is understood about this issue. In addition to and separate from induced seismicity associated with injection, the OGCD has issued guidelines to operators to follow when engaged in well stimulation activities, which some studies now seem to correlate with a small number of low intensity seismic events.

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

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The adoption and implementation of any new laws, regulations, or directives that restrict our ability to stimulate wells or to dispose of produced water, by changing the depths of disposal wells, reducing the volume of oil and gas wastewater disposed in such wells, restricting disposal well locations or otherwise, or by requiring us or third parties who dispose of our saltwater to shut down disposal wells, could increase disposal costs or require us to shut in a substantial number of our oil and gas wells or otherwise have a material adverse effect on our ability to produce oil and gas economically and, accordingly, could materially and adversely affect our business, financial condition, and results of operations. We could also face lawsuits alleging that seismic activity occurred as a result of completions or water disposal activities, resulting in damage to persons and property.

A substantial portion of our producing properties are located in limited geographic areas, making us vulnerable to risks associated with having geographically concentrated operations.

A substantial portion of our producing properties are geographically concentrated in the Permian Basin in Texas and New Mexico and our Cana area in the Mid-Continent region in Oklahoma, with these two areas comprising approximately 57% and 43%, respectively, of our oil, gas, and NGL production and approximately 64% and 36%, respectively, of our oil, gas, and NGL revenues for the year ended December 31, 2018. Approximately 57% of our estimated proved reserves were located in the Permian Basin and approximately 43% of our estimated proved reserves were located in the Mid-Continent region as of December 31, 2018.

Because of this concentration in limited geographic areas, the success and profitability of our operations may be disproportionately exposed to regional factors relative to our competitors that have more geographically dispersed operations. These factors include, among others: (i) the prices of oil and gas produced from wells in the regions and other regional supply and demand factors, including gathering, pipeline, and rail transportation capacity constraints; (ii) the availability of rigs, equipment, oil field services, supplies, and labor; (iii) the availability of processing and refining facilities; and (iv) infrastructure capacity. In addition, our operations in the Permian Basin and Mid-Continent region, as well as other areas, may be adversely affected by severe weather events such as floods, lightning, ice and other storms, and tornadoes, which can intensify competition for the items described above during months when drilling is possible and may result in periodic shortages. The concentration of our operations in limited geographic areas also increases our exposure to changes in local laws and regulations including concerning hydraulic fracturing and wastewater disposal as discussed above in “Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to engage in hydraulic fracturing during completion operations and to dispose of saltwater produced in connection with our oil and gas production, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business”, certain lease stipulations designed to protect wildlife, and unexpected events that may occur in the regions such as natural disasters, seismic events, industrial accidents, or labor difficulties. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on our financial condition, results of operations, and cash flows.

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 of 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.

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

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when drilling, completing, or operating wells that they own.

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

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

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

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

A cyber attack involving our information systems and related infrastructure, or those of our business associates, could disrupt our business and negatively impact our operations in a variety of ways, including but not limited to:

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unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;

- data corruption or operational disruption of production-related infrastructure could result in a loss of production, or accidental discharge;
- a cyber attack on a vendor or service provider could result in supply chain disruptions, which could delay or halt our major development projects;
- a cyber attack on third-party gathering, pipeline, or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues; and

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- a cyber attack on our accounting or accounts payable systems could expose us to liability to employees and third parties if their personal identifying information is obtained.

These events could damage our reputation and lead to financial losses from remedial actions, loss of business, or potential liability, which could have a material adverse effect on our financial condition, results of operations, or cash flows.

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

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

For the year ended December 31, 2018, other companies operated approximately 19% 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, and environmental hazards such as 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.

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

At December 31, 2018, our long-term debt consisted of $750 million of 4.375% senior notes due in 2024 and $750 million of 3.90% senior notes due in 2027. In addition to interest expense and principal on our long-term debt, we have demands on our cash resources including, among others, capital expenditures, operating expenses, and contractual commitments, as well as the pending anticipated closing of the acquisition of Resolute in the first quarter of 2019.

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

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

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

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

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

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

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

In addition, our revolving credit agreement requires us to maintain a total debt to capitalization ratio (as defined in the credit agreement) of not more than 65%. See Note 3 to the Consolidated Financial Statements for further information.

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

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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, such as in a corporate acquisition such as our acquisition of Resolute, to provide effective contractual protection against all or part of the identified problems. For additional risks related to our pending acquisition of Resolute, see below "Risks Concerning Cimarex's Pending Merger with Resolute Energy Corporation."

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 and the amounts spent for those leases will be lost. The combined net acreage expiring in the next three years represents approximately 4.7% of our total net undeveloped acreage at December 31, 2018. At that date, we had leases representing 193,180 net acres expiring in 2019, 55,978 net acres expiring in 2020, and 21,598 net acres expiring in 2021. 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 of 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 at times retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or 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. In addition, with respect to offshore assets, if purchasers declare bankruptcy, the United States Department of Interior may pursue former owners for decommissioning expenses, which can be substantial. See Note 8 to the Consolidated Financial Statements for further discussion regarding our asset retirement obligations.

Competition for experienced technical personnel may negatively impact our operations.

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

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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 are involved with 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. For litigation risks related to our pending acquisition of Resolute, see below "Risks Concerning Cimarex's Pending Merger with Resolute Energy Corporation."

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be limited or eliminated as a result of recently enacted or future legislation.

On December 22, 2017, the United States enacted H.R.1, commonly referred to as the Tax Cuts and Jobs Act or U.S. Tax Reform. H.R.1, among other things, includes changes to U.S. federal tax rates, imposes new limitations on the utilization of net operating losses and the deductibility of interest and executive compensation, temporarily allows for the expensing of capital expenditures, and eliminates the corporate Alternative Minimum Tax. Various proposed regulations have been issued regarding H.R.1. Until final regulations are issued the full impact of changes to the company is not known at this time. In addition, various proposals have been made recommending the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. Future legislation may be 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 gas exploration and development, and any such change could have an adverse effect on our financial position, results of operations, and cash flows, including the payment of cash taxes earlier than expected.

Risks Concerning Cimarex's Pending Merger with Resolute Energy Corporation

The merger is subject to conditions, including certain conditions that may not be satisfied, or completed on a timely basis, if at all.

The merger is subject to a number of other conditions beyond Cimarex's and Resolute's control that may prevent, delay, or otherwise materially adversely affect its completion, including the approval of the merger proposal by Resolute's stockholders at its meeting currently scheduled for February 22, 2019. Neither Cimarex nor Resolute can predict whether and when these other conditions will be satisfied. Any delay in completing the merger could cause the combined company not to realize some or all of the synergies expected to be achieved if the merger is successfully completed within its expected time frame.

Cimarex and Resolute will incur substantial transaction fees and merger-related costs in connection with the merger.

Cimarex and Resolute have incurred and expect to continue to incur non-recurring transaction fees, which include legal and advisory fees and substantial merger-related costs associated with completing the merger, combining the operations of the two companies, and achieving desired synergies. Additional unanticipated costs may be incurred in the course of the integration of the businesses of Cimarex and Resolute. The companies cannot be certain that the realization of other benefits related to the integration of the two businesses will offset the transaction and merger-related costs in the near term, or at all.

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Completion of the merger may trigger change in control or other provisions in certain agreements to which Resolute is a party.

The completion of the merger may trigger change in control or other provisions in certain agreements to which Resolute is a party. If Cimarex and Resolute are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under the agreements, potentially terminating the agreements or seeking monetary damages. Even if Cimarex and Resolute are able to negotiate waivers, the counterparties may require a fee for such waivers or seek to renegotiate the agreements on terms less favorable to Resolute or the combined company.

Lawsuits have been filed against Resolute, the directors of Resolute, Cimarex, and the subsidiaries of Cimarex created to effect the acquisition of Resolute challenging the adequacy of the disclosures made in the proxy statement/prospectus concerning the merger and an adverse ruling in one or more of these lawsuits may prevent the merger from being completed.

As of January 25, 2019, Resolute, the directors of Resolute, and in two of the cases, Cimarex, Merger Sub 1, and Merger Sub 2, have been named as defendants in five purported stockholder class actions challenging the adequacy of the disclosures to Resolute stockholders made in the proxy statement/prospectus concerning the merger. Three complaints were filed in the U.S. District Court for the District of Delaware, one complaint was filed in the U.S. District Court for the Southern District of New York, and one complaint was filed in U.S. District Court for the District of Colorado. Additional lawsuits arising out of the merger may be filed in the future. There can be no assurance that defendants will be successful in the outcome of the pending or any potential future lawsuits. A preliminary injunction could delay or jeopardize the completion of the merger.

Risks Relating to the Combined Company Following the Merger

If completed, the merger may not achieve its intended results, and Cimarex and Resolute may be unable to successfully integrate their operations.

Cimarex and Resolute entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, expanding Cimarex's asset base and creating synergies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Cimarex and Resolute can be integrated in an efficient and effective manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of each company's ongoing businesses, processes, and systems or inconsistencies in standards, controls, procedures, practices, policies, and compensation arrangements, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger. The combined company's results of operations could also be adversely affected by any issues attributable to either company's operations that arise from or are based on events or actions that occur prior to the closing of the merger. The companies may have difficulty addressing possible differences in corporate cultures and management philosophies. The integration process is subject to a number of uncertainties, and no assurance can be given whether anticipated benefits will be realized or, if realized, the timing of their realization. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect the combined company's future business, financial condition, operating results, and prospects.

The combined company is expected to incur expenses related to the integration of Cimarex and Resolute.

The combined company is expected to incur expenses in connection with the integration of Cimarex and Resolute. There are a large number of processes, policies, procedures, operations, technologies, and systems that must be integrated, including purchasing, accounting and finance, sales, billing, payroll, pricing, revenue management, maintenance, marketing, and benefits. While Cimarex and Resolute have assumed that a certain level of expenses will be incurred, there are many factors beyond their control that could affect the total amount or the timing of the integration expenses. Moreover, many of the expenses that will be incurred are, by their nature, difficult to estimate accurately. These integration expenses likely will result in the combined company taking charges against earnings following the completion of the merger, and the amount and timing of such charges are uncertain at present.

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Uncertainties associated with the merger may cause a loss of management personnel and other key employees, which could adversely affect the future business and operations of the combined company.

Cimarex and Resolute are dependent on the experience and industry knowledge of their officers and other key employees to execute their business plans. Each company's success until the merger and the combined company's success after the merger will depend in part upon the ability of Cimarex and Resolute to retain key management personnel and other key employees. Current and prospective employees of Cimarex and Resolute may experience uncertainty about their roles within the combined company following the merger, which may have an adverse effect on the ability of Cimarex and Resolute to attract or retain key management and other key personnel. Accordingly, no assurance can be given that the combined company will be able to attract or retain key management personnel and other key employees of Cimarex and Resolute to the same extent that Cimarex and Resolute have previously been able to attract or retain their own employees.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

The information set forth under the heading “Litigation” in Note 10 to the Consolidated Financial Statements included in Part II, Item 8 of this Form 10-K, is incorporated by reference in response to this item. For information regarding litigation related to the pending acquisition of Resolute, which Cimarex believes is without merit and intends to defend vigorously, see “Risk Factors—Risks Concerning Cimarex’s Pending Merger with Resolute Energy Corporation.” Cimarex does not believe the ultimate resolution of the pending acquisition litigation will have a material adverse effect on our financial condition or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR 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 2018. Future dividend payments will depend on the company's level of earnings, financial requirements, and other factors considered relevant by the Board of Directors.

The closing price of Cimarex stock as reported on the NYSE on January 31, 2019, was $75.34. At January 31, 2019, Cimarex's 95,755,298 shares of outstanding common stock were held by approximately 1,618 stockholders of record.

Issuer Purchases of Equity Securities

The following table sets forth information regarding repurchases of our common stock during the year ended December 31, 2018. The shares repurchased represent shares of our common stock that employees elected to surrender to satisfy their tax withholding obligations upon the vesting of shares of restricted stock. Cimarex does not consider this a share buyback program.

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Maximum number of shares that may yet be purchased under the plans or programs
January 1-31, 2018	2,421	$126.16	—	—
April 1-30, 2018	3,527	98.86	—	—
May 1-31, 2018	2,970	98.37	—	—
July 1-31, 2018	49,241	99.80	—	—
September 1-30, 2018	6,123	89.73	—	—
November 1-30, 2018	1,174	91.37	—	—
December 1-31, 2018	74,790	75.22	—	—
Total	140,246	$86.58	—	—

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Stock Performance Graph

The following graph shows the cumulative five-year total return 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, 2013 to December 31, 2018. The stock price performance included in this graph is not necessarily indicative of future stock price performance.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN*
Among Cimarex Energy Co., the S&P 500 Index,
the Dow Jones US Exploration & Production Index, and the S&P Oil & Gas Exploration & Production Index
* $100 invested in 12/31/13 in stock or index, including reinvestment of dividends. Fiscal year ending December 31.

A tabular presentation of the data in the above graph is provided below.

	2013	2014	2015	2016	2017	2018
Cimarex Energy Co.	$100.00	$101.56	$86.11	$131.44	$118.33	$60.17
S&P 500	$100.00	$113.69	$115.26	$129.05	$157.22	$150.33
Dow Jones US Exploration & Production	$100.00	$89.23	$68.05	$84.71	$85.81	$70.57
S&P Oil & Gas Exploration & Production	$100.00	$89.41	$58.87	$78.22	$73.29	$58.99

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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.

	Years Ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands, except per share amounts)				
Operating results:					
Oil, gas, and NGL sales	$2,297,645	$1,874,003	$1,221,218	$1,417,538	$2,372,829
Total revenues (1)	$2,339,017	$1,918,249	$1,257,345	$1,452,619	$2,424,176
Net income (loss) (2)	$791,851	$494,329	$(408,803)	$(2,579,604)	$526,498
Earnings (loss) per share to common stockholders:					
Basic	$8.32	$5.19	$(4.38)	$(27.75)	$6.01
Diluted	$8.32	$5.19	$(4.38)	$(27.75)	$6.00
Cash dividends declared per share	$0.68	$0.32	$0.32	$0.64	$0.64
Cash flow data:					
Net cash provided by operating activities (3)	$1,550,994	$1,096,564	$625,849	$725,728	$1,632,925
Net cash used by investing activities	$(1,085,618)	$(1,265,897)	$(692,410)	$(1,008,605)	$(1,740,467)
Net cash (used) provided by financing activities (3)	$(65,244)	$(83,009)	$(59,945)	$656,397	$508,873

	December 31,				
	2018	2017	2016	2015	2014
	(in thousands, except proved reserves amounts)				
Balance sheet data:					
Cash and cash equivalents	$800,666	$400,534	$652,876	$779,382	$405,862
Oil and gas properties, net (2)	$3,715,330	$3,241,530	$2,354,267	$2,741,282	$6,637,796
Goodwill	$620,232	$620,232	$620,232	$620,232	$620,232
Total assets (2) (4)	$6,062,084	$5,042,639	$4,237,724	$4,708,422	$8,442,554
Deferred income tax liability (asset)	$334,473	$101,618	$(55,835)	$157,162	$1,657,456
Long-term obligations:					
Long-term debt (principal)	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000
Other	$200,564	$206,249	$184,444	$197,216	$193,629
Stockholders' equity	$3,329,786	$2,568,278	$2,042,989	$2,458,357	$4,331,966
Proved Reserves:					
Oil (MBbls)	146,538	137,238	105,878	107,798	118,992
Gas (Bcf)	1,591	1,608	1,471	1,517	1,667
NGL (MBbls)	179,436	153,860	130,633	124,277	125,273
Total (MBOE)	591,195	559,037	481,748	484,901	522,054

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(1) Effective January 1, 2018, we adopted the provisions of Accounting Standards Codification 606, Revenue from Contracts with Customers ("ASC 606"), utilizing the modified retrospective approach. Because we utilized the modified retrospective approach, there was no impact to prior periods' reported amounts. Application of ASC 606

has no impact on our net income or cash flows from operations; however, certain costs classified as Transportation, processing, and other operating in the statement of operations under prior accounting standards are now reflected

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as deductions from revenue. The adoption of ASC 606 reduced revenue for the year ended December 31, 2018 by $44.8 million from what it would have been under prior accounting standards.

(2) During 2016 and 2015, we recorded non-cash full cost ceiling test impairments of our oil and gas properties totaling $757.7 million ($481.4 million, net of tax) and $4.03 billion ($2.56 billion, net of tax), respectively.

(3) We adopted Accounting Standards Update 2016-09, Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09") on January 1, 2017. Pursuant to ASU 2016-09, we adjusted the statements of cash flows for all prior periods presented. For the years ended December 31, 2016, 2015, and 2014, we decreased cash outflows for operating activities and cash inflows for financing activities by $26.6 million, $34.2 million, and $13.6 million, respectively, for the payment of employee tax withholdings on the net settlement of equity-classified awards and for excess tax benefits, as applicable.

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

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. Refer to CAUTIONARY INFORMATION ABOUT FORWARD-LOOKING STATEMENTS in Part I of this report for important information about these types of statements.

OVERVIEW

Cimarex is an independent oil and gas exploration and production company. Our operations are entirely located in the United States, mainly in Oklahoma, Texas, and New Mexico. Currently our operations are focused in two main areas: the Permian Basin and the Mid-Continent. 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 increase shareholder value through the profitable long-term growth of our proved reserves and production while seeking to minimize our impact on the communities in which we operate for the long-term. Our strategy centers on maximizing cash flow from producing properties so that we can reinvest in exploration and development opportunities and provide cash returns to shareholders through increasing dividends. We consider merger and acquisition opportunities that enhance our competitive position and we occasionally divest non-core assets.

On August 31, 2018, we closed on the divestiture of oil and gas properties principally located in Ward County, Texas for a sales price of $544.5 million, as adjusted to reflect the resolution of all asserted defects. As of December 31, 2018, we have received $534.6 million in net cash proceeds as adjusted for customary closing adjustments to reflect an effective date of April 1, 2018 and transaction costs. Final settlement, which will reflect customary post-closing adjustments, is scheduled to occur by the end of first quarter 2019. This divestiture did not significantly alter the relationship between capitalized costs and proved reserves, therefore, in accordance with the full cost method of accounting, no gain or loss was recognized. This divestiture is part of our continuous portfolio optimization and high-grading of our investment opportunities.

On November 18, 2018, we entered into an agreement and plan of merger to acquire Resolute Energy Corporation ("Resolute") in a cash and stock transaction valued at a total purchase price of approximately $1.6 billion, including the assumption of Resolute's long-term debt, which was $710 million as of September 30, 2018. Under the terms of the agreement, Resolute shareholders will have the right to receive 0.3943 shares of Cimarex common stock, $35.00 per share in cash, or a combination of $14.00 per share in cash and 0.2366 shares of Cimarex common stock. The amount of stock and cash is subject to proration for a total stock and cash mix of 60% and 40%, respectively. This pending acquisition will expand Cimarex's footprint in Reeves County, Texas by 21,100 net acres that are complementary to our existing Reeves County position. The transaction, which is expected to be completed by the end of the first quarter 2019, is subject to the approval of Resolute shareholders, which includes voting agreements with certain

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shareholders that collectively beneficially own approximately 26% of the outstanding Resolute voting power and the satisfaction of certain regulatory approvals and other customary closing conditions.

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

Our investments are generally funded with cash flow provided by operating activities together with cash on hand, bank borrowings, sales of non-strategic assets, and, from time to time, public financing based on our monitoring of capital markets and our balance sheet. 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 unpredictable fluctuations in commodity prices.

Market Conditions

The oil and gas industry is cyclical and commodity prices can fluctuate significantly. We expect this volatility to persist. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, inventory storage levels, weather conditions, and other factors.

During 2018, as compared to 2017, market prices for oil have improved, while market prices for gas have declined. During 2018, average NYMEX oil and gas prices were $64.77 per barrel and $3.09 per Mcf, respectively, representing an increase of 27% and a decrease of 1%, respectively, from the average NYMEX oil and gas prices for 2017. Local market prices for oil and gas can be impacted by pipeline capacity constraints limiting takeaway and increasing basis differentials. Gas production growth and pipeline constraints in the Permian Basin and Mid-Continent region and oil production growth and pipeline constraints in the Permian Basin have resulted in higher basis differentials and, therefore, lower realized prices. The average prices per barrel of oil and Mcf of gas that we realized were less than the WTI Cushing and Henry Hub indices by the amounts shown in the table below for the periods indicated.

	Average Price Differentials				
2018	Year	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Permian Basin oil	$9.82	$ 11.64	$ 14.34	$ 8.05	$ 3.12
Mid-Continent oil	$2.46	$ 2.33	$ 1.08	$ 2.18	$ 2.34
Permian Basin gas	$1.40	$ 2.21	$ 1.25	$ 1.31	$ 0.78
Mid-Continent gas	$0.86	$ 0.83	$ 0.94	$ 1.03	$ 0.70
2017					
Permian Basin oil	$3.98	$ 3.99	$ 4.06	$ 4.14	$ 3.96
Mid-Continent oil	$3.52	$ 2.65	$ 2.99	$ 4.19	$ 5.10
Permian Basin gas	$0.39	$ 0.37	$ 0.29	$ 0.42	$ 0.43
Mid-Continent gas	$0.33	$ 0.33	$ 0.38	$ 0.34	$ 0.23

Pipeline expansion projects in the Permian Basin are expected to ease capacity constraints as they come online over the next few years, which is reflected in the current futures markets that show narrowing differentials. However, if pipeline constraints remain, higher differentials will persist or potentially worsen. Our revenue, profitability, and future growth are highly dependent on the prices we receive for our oil and gas production. See RESULTS OF OPERATIONS Revenues below for further information regarding our realized commodity prices.

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2018 Summary of Operating and Financial Results

- Total daily production volumes increased 17% to 221.9 MBOE per day.
- Oil volumes increased 18% to 67.7 MBbls per day.
- Gas volumes increased 10% to 563.9 MMcf per day.
- NGL volumes increased 27% to 60.3 MBbls per day.
- Total production revenue increased 23% to $2.30 billion.
- Year-end proved reserves increased 6% to 591.2 MMBOE, as compared to 559.0 MMBOE at year-end 2017.
- Exploration and development capital investments were $1.57 billion, as compared to $1.28 billion in 2017.
- Cash flow provided by operating activities increased 41% to $1.55 billion.
- Cash on hand at December 31, 2018 was $800.7 million.

For the year ended December 31, 2018, we had net income of $791.9 million ($8.32 per diluted share) as compared to net income of $494.3 million ($5.19 per diluted share) in 2017. Production revenue in 2018 was positively impacted by increased production volumes across all products as well as increased realized oil and NGL commodity prices. Lower realized gas prices negatively impacted 2018. Year-over-year changes are discussed further in the RESULTS OF OPERATIONS section that follows.

Proved Reserves

Our proved reserves by region at December 31, 2018 and 2017 were as follows:

	December 31, 2018			
	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)
Permian Basin	727,985	116,378	96,533	334,241
Mid-Continent	861,440	29,908	82,826	256,307
Other	1,896	252	77	647
Total	1,591,321	146,538	179,436	591,195

	December 31, 2017			
	Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total (MBOE)
Permian Basin	573,757	105,198	68,530	269,354
Mid-Continent	1,032,695	31,853	85,292	289,261
Other	1,183	187	38	422
Total	1,607,635	137,238	153,860	559,037

Year-end 2018 proved reserves increased approximately 6% to 591.2 MMBOE, compared to 559.0 MMBOE at year-end 2017. Proved gas reserves were 1.59 Tcf, proved oil reserves were 146.5 MMBbls, and proved NGL reserves were 179.4 MMBbls. Reserves in the Permian Basin accounted for 57% of our total proved reserves with nearly all of the remainder in our Mid-Continent region. See SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED) in Item 8 for a more detailed discussion regarding year-over-year changes in our proved reserves.

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

RESULTS OF OPERATIONS

Effective January 1, 2018, we adopted the provisions of Accounting Standards Codification 606, Revenue from Contracts with Customers ("ASC 606"), utilizing the modified retrospective approach, which we applied to contracts that were not completed as of that date. Because we utilized the modified retrospective approach, there was no impact to prior periods' reported amounts. Application of ASC 606 has no impact on our net income or cash flows from operations; however, certain costs classified as Transportation, processing, and other operating in the statement of operations under prior accounting standards are now reflected as deductions from revenue under ASC 606. The following table presents the impact on our Oil sales, Gas sales, and NGL sales and on our Transportation, processing, and other operating costs from the application of ASC 606 in the current reporting period:

	Years Ended December 31,				
	2018			2017	2016
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported	As Reported
Oil sales	$1,398,813	$—	$1,398,813	$981,646	$632,934
Gas sales	425,233	(16,482)	408,751	516,936	388,786
NGL sales	518,410	(28,329)	490,081	375,421	199,498
Total oil, gas, and NGL sales	$2,342,456	$(44,811)	$2,297,645	$1,874,003	$1,221,218
Transportation, processing, and other operating costs	$245,613	$(44,811)	$200,802	$231,640	$190,725

Almost all our revenues are derived from sales of our oil, natural gas, and NGL production. Increases or decreases in our revenues, profitability, and future production growth are highly dependent on the commodity prices we receive. Prices are market driven and we expect that future prices will continue to fluctuate due to supply and demand factors, availability of transportation, seasonality, geopolitical, and economic factors. See Item 7A QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for more information regarding the sensitivity of our revenues to price fluctuations.

2018 Compared to 2017

Revenues

A decrease in realized gas prices as well as the impact of ASC 606, as discussed above, negatively impacted our revenues in 2018 as compared to 2017. However, increases in production volumes and realized oil and NGL prices in 2018 as compared to 2017 more than offset declines in gas sales, causing our revenues to increase by $423.6 million, or 23%, from prior year. The following table shows our production revenues for 2018 and 2017 as well as the change in revenues due to changes in prices and volumes.

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Production Revenue (in thousands)	Years Ended December 31, 2018	2017	Variance Between 2018 / 2017		Price / Volume Variance Price	Volume	Total
Oil sales	$1,398,813	$981,646	$417,167	42 %	$235,981	$181,186	$417,167
Gas sales	408,751	516,936	(108,185)	(21)%	(158,494)	50,309	(108,185)
NGL sales	490,081	375,421	114,660	31 %	14,736	99,924	114,660
	$2,297,645	$1,874,003	$423,642	23 %	$92,223	$331,419	$423,642

The table below presents our production volumes by commodity, our average realized commodity prices, and certain major U.S. index prices. The sale of our Permian Basin oil production is typically tied to the WTI Midland benchmark price and the sale of our Mid-Continent oil production is typically tied to the WTI Cushing benchmark price. During 2018 and 2017, 77% and 78%, respectively, of our oil production was in the Permian Basin with the majority of the remainder in the Mid-Continent region. Our realized prices do not include settlements of commodity derivative contracts.

	Years Ended December 31, 2018		2017	Variance Between 2018 / 2017	
Oil					
Total volume — MBbls	24,710		20,861	3,849	18 %
Total volume — MBbls per day	67.7		57.2	10.5	18 %
Percentage of total production	31 %		30 %		
Average realized price — per barrel	$56.61		$47.06	$9.55	20 %
Average WTI Midland price — per barrel	$58.31		$50.45	$7.86	16 %
Average WTI Cushing price — per barrel	$64.77		$50.94	$13.83	27 %
Gas					
Total volume — MMcf	205,837		187,468	18,369	10 %
Total volume — MMcf per day	563.9		513.6	50.3	10 %
Percentage of total production	42 %		45 %		
Average realized price — per Mcf	$1.99	(1)	$2.76	$(0.77)	(28)%
Average Henry Hub price — per Mcf	$3.09		$3.11	$(0.02)	(1)%
NGL					
Total volume — MBbls	21,994		17,374	4,620	27 %
Total volume — MBbls per day	60.3		47.6	12.7	27 %
Percentage of total production	27 %		25 %		
Average realized price — per barrel	$22.28	(2)	$21.61	$0.67	3 %
Total					
Total production — MBOE	81,010		69,479	11,531	17 %
Total production — MBOE per day	221.9		190.4	31.5	17 %
Average realized price — per BOE	$28.36	(3)	$26.97	$1.39	5 %

(1) ASC 606 reduced the average realized gas price by $0.08 per Mcf for the year ended December 31, 2018.
(2) ASC 606 reduced the average realized NGL price by $1.29 per barrel for the year ended December 31, 2018.
(3) ASC 606 reduced the average realized total price by $0.56 per BOE for the year ended December 31, 2018.

Our 2018 daily production volumes were 221.9 MBOE, a 17% increase from 2017. This increase is the result of increased drilling and completion activity during 2018 as compared to 2017. See Production Volumes, Prices, and Costs and Exploration and Development Overview in Items 1 and 2 of this report for production information by region and a discussion of our drilling activities.

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Other Revenues

We transport, process, and market some third-party gas that is associated with our equity gas. We market and sell gas for other working interest owners under short term agreements and may earn a fee for such services. The table below reflects income from third-party gas gathering and processing and our net marketing margin for marketing third-party gas.

Gas Gathering and Marketing (in thousands):	Years Ended December 31, 2018	2017	Variance Between 2018 / 2017
Gas gathering and other	$ 41,180	$ 43,751	$ (2,571)
Gas marketing	$ 192	$ 495	$ (303)

Fluctuations in revenues from gas gathering and gas marketing activities are a function of increases and decreases in volumes, commodity prices, and gathering rate charges. The decreases from 2017 are primarily due to lower rates and decreases in prices and volumes.

Operating Costs and Expenses

Costs associated with producing oil and gas are substantial. Among other factors, some of these costs vary with commodity prices, some trend with the volume of production, others are a function of the number of wells we own, some depend on the prices charged by service companies, and some fluctuate based on a combination of the foregoing.

Total operating costs and expenses of $1.29 billion in 2018 were 11% higher than the $1.17 billion incurred in 2017. The primary drivers of the increase were depletion, taxes other than income, production expense, and other operating expense, with these being partially offset by lower transportation and processing and increased gains on derivative instruments. The following table shows our operating costs and expenses for the years indicated and a discussion of year-over-year differences follows.

Operating Costs and Expenses (in thousands, except per BOE)	Years Ended December 31, 2018	2017	Variance Between 2018 / 2017	Per BOE 2018	Per BOE 2017
Depreciation, depletion, and amortization	$590,473	$446,031	$ 144,442	$7.29	$6.42
Asset retirement obligation	7,142	15,624	(8,482)	$0.09	$0.22
Production	293,213	262,180	31,033	$3.62	$3.77
Transportation, processing, and other operating	200,802	231,640	(30,838)	$2.48	$3.33
Gas gathering and other	41,964	35,840	6,124	$0.52	$0.52
Taxes other than income	125,169	89,864	35,305	$1.55	$1.29
General and administrative	80,850	79,996	854	$1.00	$1.15
Stock compensation	22,895	26,256	(3,361)	$0.28	$0.38
Gain on derivative instruments, net	(85,959)	(21,210)	(64,749)	N/A	N/A
Other operating expense, net	15,500	1,314	14,186	N/A	N/A
	$1,292,049	$1,167,535	$ 124,514		

Depreciation, Depletion, and Amortization

Depletion of our producing properties is computed using the units-of-production method. The economic life of each producing well depends upon the estimated proved reserves for that well, which in turn depend upon the assumed realized sales price for future production. Therefore, fluctuations in oil and gas prices will impact the level of proved reserves used in the calculation. Higher prices generally have the effect of increasing reserves, which reduces depletion expense. Conversely, lower prices generally have the effect of decreasing reserves, which increases depletion expense. The cost of replacing production also impacts our depletion expense. In addition, changes in estimates of reserve quantities, estimates of operating and future development costs, reclassifications of properties from unproved to proved,

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and impairments of oil and gas properties will also impact depletion expense. While the increase in oil prices has more than offset the decrease in gas prices during 2018 as compared to 2017, thus increasing our reserves, the increase in production combined with our ongoing exploration and development capital expenditures throughout 2018 have resulted in an overall increase in depletion expense.

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. Depreciation, depletion, and amortization ("DD&A") consisted of the following for the years indicated:

	Years Ended December 31,		Variance	Per BOE	
DD&A Expense (in thousands, except per BOE)	2018	2017	Between 2018 / 2017	2018	2017
Depletion	$ 538,919	$ 399,328	$ 139,591	$6.65	$5.75
Depreciation	51,554	46,703	4,851	0.64	0.67
	$ 590,473	$ 446,031	$ 144,442	$7.29	$6.42

Asset Retirement Obligation

Asset retirement obligation expense is typically primarily comprised of accretion expense. In periods subsequent to the initial measurement of an asset retirement obligation liability at present value, a period-to-period increase in the carrying amount of the liability is recognized as accretion expense, which represents the effect of the passage of time on the amount of the liability. An equivalent amount is added to the carrying amount of the liability. Also included in asset retirement obligation expense are gains and losses recognized on the settlement of asset retirement obligation liabilities.

Asset retirement obligation expense decreased 54%, or $8.5 million, compared to 2017. The expense in 2017 included $10.5 million for the estimated liability to decommission two offshore properties in the Gulf of Mexico in which we were a prior lessee. In January 2018, the Bureau of Safety and Environmental Enforcement ("BSEE") notified us and other prior lessees that the current lessee of the properties had filed a petition for relief under the bankruptcy code and, as a result, had defaulted on its obligation to decommission the properties. Consequently, BSEE ordered us and other prior lessees to decommission all wells, pipelines, platforms, and other facilities related to these properties. Our estimate of our liability may change as we refine our understanding of the extent of our obligations under the orders from BSEE and obtain additional information on decommissioning costs.

Production

Production expense generally consists of costs for labor, equipment, maintenance, saltwater disposal, compression, power, treating, and miscellaneous other costs (lease operating expense). Production expense also includes well workover activity necessary to maintain production from existing wells. Production expense consists of lease operating expense and workover expense as follows:

	Years Ended December 31,		Variance	Per BOE	
Production Expense (in thousands, except per BOE)	2018	2017	Between 2018 / 2017	2018	2017
Lease operating expense	$ 241,885	$ 215,148	$ 26,737	$2.99	$3.10
Workover expense	51,328	47,032	4,296	0.63	0.67
	$ 293,213	$ 262,180	$ 31,033	$3.62	$3.77

Through efficiency gains and increasing daily production by 17% during 2018 as compared to 2017, we reduced our per unit lease operating expense by 4% between these two periods. On an absolute basis, lease operating expense in 2018 increased 12%, or $26.7 million, compared to 2017. The increase was primarily caused by increases in the following costs: (i) equipment rental, primarily additional compressors, (ii) saltwater disposal costs, due to increased water volumes, (iii) tank battery and processing equipment and maintenance, primarily due to the addition of new wells, (iv) contract pumpers, (v) environmental compliance, primarily emissions-related, (vi) electricity, primarily due to the addition of new wells, and (vii) chemicals and treating, due to increased water volumes.

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Workover expense increased 9%, or $4.3 million, during 2018 as compared to 2017. During 2018, we had more workover projects than we did in 2017. During 2018, we incurred the majority of our workover expense on major well workovers and artificial lift conversions, with artificial lift conversions being the largest increase from 2017. Partially offsetting the increase in expense on workover projects was the receipt of insurance proceeds during 2018 related to a previous flood and line rupture. Remediation and repairs for these events were charged to workover expense at the time incurred. Generally, workover costs will fluctuate based on the amount of maintenance and remedial activity required during the period.

Transportation, Processing, and Other Operating

Transportation, processing, and other operating costs principally consist of expenditures to prepare and transport production from the wellhead, including gathering, fuel, compression, and processing costs. Costs vary by region and will fluctuate with increases or decreases in production volumes, contractual fees, and changes in fuel and compression costs.

Transportation, processing, and other operating costs in 2018 were 13%, or $30.8 million, lower than in 2017. This decrease is due to our adoption of ASC 606 effective January 1, 2018, whereby certain transportation and processing costs are now reclassified out of transportation, processing, and other operating costs and are treated as a deduction from revenue. The adoption of ASC 606 reduced Transportation, processing, and other operating costs by $44.8 million in 2018. The reduction was partially offset by increased costs due to increased production volumes. See Note 1 to the Consolidated Financial Statements for additional information regarding the adoption of ASC 606.

Gas Gathering and Other

Gas gathering and other includes costs associated with operating our gas gathering and processing infrastructure, including product costs and operating and maintenance expenses. Gas gathering and other in 2018 was 17%, or $6.1 million, higher than in 2017. The increase was primarily due to overall increases in operating costs partially offset by lower product costs associated with processing third-party production due to lower volumes and prices.

Taxes Other than Income

Taxes other than income consist of production (or severance) taxes, ad valorem taxes, and other taxes. State and local taxing authorities assess these taxes, with production taxes being based on the volume or value of production and ad valorem taxes being based on the value of properties. Production taxes make up the majority of this expense for us, with revenue-based production taxes being the largest component of these taxes. In 2018, taxes other than income increased 39%, or $35.3 million, from 2017. This increase is primarily due to the increase in revenue in 2018 as well as due to increased ad valorem taxes in 2018 due to higher assessed valuations and new wells. Both years include credits for tax refunds. We had $15.7 million in credits in 2018, primarily for Texas marketing cost deduction refunds. We had $9.6 million in credits in 2017, primarily for Texas high-cost gas well refunds. Taxes other than income were 5.4% and 4.8% of production revenues for 2018 and 2017, respectively.

General and Administrative

General and administrative (“G&A”) expense consists primarily of salaries and related benefits, office rent, legal and consulting fees, systems costs, and other administrative costs incurred. 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. The amount of expense capitalized varies and depends on whether the cost incurred can be directly identified with acquisition, exploration, and development activities. The percentage of gross G&A capitalized was 47% and 49% during 2018 and 2017, respectively. The table below shows our G&A costs.

	Years Ended December 31,		Variance
General and Administrative Expense (in thousands):	2018	2017	Between 2018 / 2017
Gross G&A	$ 152,827	$ 156,389	$ (3,562)
Less amounts capitalized to oil and gas properties	(71,977)	(76,393)	4,416
G&A expense	$ 80,850	$ 79,996	$ 854

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Stock Compensation

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

Stock Compensation Expense (in thousands):	Years Ended December 31, 2018	2017	Variance Between 2018 / 2017
Restricted stock awards:			
Performance stock awards	$ 23,083	$ 26,020	$ (2,937)
Service-based stock awards	20,385	19,746	639
	43,468	45,766	(2,298)
Stock option awards	2,456	2,599	(143)
Total stock compensation cost	45,924	48,365	(2,441)
Less amounts capitalized to oil and gas properties	(23,029)	(22,109)	(920)
Stock compensation expense	$ 22,895	$ 26,256	$ (3,361)

Periodic stock compensation expense will fluctuate based on the grant date fair value of awards, the number of awards, the requisite service period of the awards, employee forfeitures, and the timing of the awards. The decrease in total stock compensation cost in 2018 as compared to 2017 is primarily due to performance stock award forfeitures during the second quarter 2018. Our accounting policy is to account for forfeitures in compensation cost when they occur, therefore, all the previously recognized expense on the forfeited award is reversed at the time of forfeiture.

Gain on Derivative Instruments, Net

Net gains and losses on our derivative instruments are a function of fluctuations in the underlying commodity index prices as compared to the contracted prices and the monthly cash settlements (if any) of the instruments. We have elected not to designate our derivatives as hedging instruments for accounting purposes and, therefore, we do not apply hedge accounting treatment to our derivative instruments. Consequently, changes in the fair value of our derivative instruments and cash settlements on the instruments are included as a component of operating costs and expenses as either a net gain or loss on derivative instruments. Cash settlements of our contracts are included in cash flows from operating activities in our statements of cash flows. The following table presents the components of Gain on derivative instruments, net for the years indicated. See Note 4 to the Consolidated Financial Statements for additional information regarding our derivative instruments.

Gain on Derivative Instruments, Net (in thousands):	Years Ended December 31, 2018	2017	Variance Between 2018 / 2017
Decrease (increase) in fair value of derivative instruments, net:			
Gas contracts	$ 15,742	$ (40,226)	$ 55,968
Oil contracts	(126,130)	17,383	(143,513)
	(110,388)	(22,843)	(87,545)
Cash (receipts) payments on derivative instruments, net:			
Gas contracts	(13,794)	(4,557)	(9,237)
Oil contracts	38,223	6,190	32,033
	24,429	1,633	22,796
Gain on derivative instruments, net	$ (85,959)	$ (21,210)	$ (64,749)

Other Operating Expense, Net

Other operating expense, net increased $14.2 million in 2018 as compared to 2017. This expense is comprised primarily of litigation settlements and allowance for doubtful accounts adjustments. The increase in expense in 2018 is due to a $14.2 million increase in litigation settlements.

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Other Income and Expense

Other Income and Expense (in thousands):	Years Ended December 31, 2018	2017	Variance Between 2018 / 2017
Interest expense	$ 68,224	$ 74,821	$ (6,597)
Capitalized interest	(20,855)	(22,948)	2,093
Loss on early extinguishment of debt	—	28,187	(28,187)
Other, net	(22,908)	(11,342)	(11,566)
	$ 24,461	$ 68,718	$ (44,257)

The majority of our interest expense relates to interest on our senior unsecured notes. Also included in interest expense is the amortization of debt issuance costs and discount, as well as miscellaneous interest expense. See LIQUIDITY AND CAPITAL RESOURCES Long-Term Debt below for further information regarding our debt. The decrease in interest expense in 2018 as compared to 2017 is due to the completion of a tender offer and redemption of $750 million 5.875% senior notes and the issuance of $750 million 3.90% senior notes, both of which occurred during the second quarter of 2017. The $28.2 million loss on early extinguishment of debt incurred during 2017 was also associated with the debt tender offer and redemption. The loss was composed primarily of tender and redemption premiums of $22.6 million and the write-off of $5.3 million of unamortized debt issuance costs. The original maturity date of the 5.875% notes was May 1, 2022.

We capitalize interest on non-producing leasehold costs, the in-progress costs of drilling and completing wells, and constructing midstream assets. Capitalized interest will fluctuate based on the rates applicable to borrowings outstanding during the period and the amount of costs subject to interest capitalized. The amount of costs subject to interest capitalization was lower in 2018 as compared to 2017, thus reducing our capitalized interest in 2018. Also contributing to lower capitalized interest in 2018 was a lower average interest rate on borrowings outstanding due to the replacement of our 5.875% notes with 3.90% notes in the second quarter of 2017.

Other, net includes interest income of $11.1 million and $5.4 million in 2018 and 2017, respectively. The increase in interest income in 2018 is primarily due to the cash proceeds we received from our Ward County property divestiture at the end of August 2018, which we subsequently invested the majority of in short-term interest-bearing accounts. Additionally, interest rates have increased throughout 2017 and 2018. Other components of Other, net include miscellaneous income and expense items that vary from period to period, including gain or loss related to the sale or value of oil and gas well equipment and supplies, gain or loss on miscellaneous fixed asset sales, and income and expense associated with other non-operating activities.

Income Tax Expense (Benefit)

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

Income Tax Expense (Benefit) (in thousands):	Years Ended December 31, 2018	2017	Variance Between 2018 / 2017
Current tax benefit	$ (2,624)	$ (2,812)	$ 188
Deferred tax expense	233,280	190,479	42,801
	$ 230,656	$ 187,667	$ 42,989
Combined federal and state effective income tax rate	22.6 %	27.5 %	

On December 22, 2017, the United States enacted H.R.1 (Public Law 115-97), commonly referred to as the Tax Cuts and Jobs Act or U.S. Tax Reform. H.R.1, among other things, includes changes to U.S. federal tax rates, imposes new limitations on the utilization of net operating losses and the deductibility of interest and executive compensation, allows for the expensing of capital expenditures, and eliminates the corporate Alternative Minimum Tax. We remeasured the deferred tax assets and liabilities as of December 31, 2017 to reflect the reduction in the U.S. income tax rate from 35% to 21% for years after 2017 and, as a result of this remeasurement, we recorded an income tax benefit of $61.1 million and a corresponding $61.1 million decrease in the net deferred tax liabilities as of December 31, 2017. We believe the accounting for the effects of H.R.1 recognized in the December 31, 2017 financial statements is materially complete. During 2018, no other adjustments were made. As a result of H.R.1, we expect our effective tax rate in future periods will be lower than in periods prior to enactment. In addition, the limitations on utilization of net operating losses and deductibility of interest and executive compensation may result in the payment of cash taxes earlier than expected.

Our combined federal and state effective tax rates, as shown above, differ from the statutory rate primarily due to state income taxes, non-deductible expenses, revisions, and the impact of changes in tax law. See Note 9 to the Consolidated Financial Statements for further information regarding our income taxes.

RESULTS OF OPERATIONS

2017 Compared to 2016

Summary

For the year ended December 31, 2017, we had net income of $494.3 million ($5.19 per diluted share), up from a net loss of $408.8 million ($4.38 per diluted share) in 2016. Production revenue in 2017 was positively impacted by increased realized commodity prices and production volumes. Lower commodity prices negatively impacted 2016, including resulting in $757.7 million of impairments of our oil and gas properties in that year. Year-over-year changes are discussed further as follows. Also refer to the “2018 Compared to 2017” section above for general information regarding various statement of operations line items.

Revenues

Realized prices and production volumes were higher in 2017 as compared to 2016, which caused our revenues to increase by $652.8 million, or 53%, from the prior year. The following table shows our production revenue for the years indicated as well as the change in revenue due to changes in prices and volumes.

	Years Ended December 31,				Price / Volume Variance		
Production Revenue (in thousands)	2017	2016	Variance Between 2017 / 2016		Price	Volume	Total
Oil sales	$981,646	$632,934	$348,712	55%	$182,742	$165,970	$348,712
Gas sales	516,936	388,786	128,150	33%	84,361	43,789	128,150
NGL sales	375,421	199,498	175,923	88%	131,347	44,576	175,923
	$1,874,003	$1,221,218	$652,785	53%	$398,450	$254,335	$652,785

The table below presents our production volumes by commodity, our average realized commodity prices, and certain major U.S. index prices. The sale of our Permian Basin oil production is typically tied to the WTI Midland benchmark price and the sale of our Mid-Continent oil production is typically tied to the WTI Cushing benchmark price. During 2017 and 2016, 78% and 80%, respectively, of our oil production was in the Permian Basin with the majority of the remainder in the Mid-Continent region. Our realized prices do not include settlements of commodity derivative contracts.

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	Years Ended December 31, 2017	2016	Variance Between 2017 / 2016	
Oil				
Total volume — MBbls	20,861	16,528	4,333	26%
Total volume — MBbls per day	57.2	45.2	12.0	27%
Percentage of total production	30 %	28 %		
Average realized price — per barrel	$47.06	$38.30	$8.76	23%
Average WTI Midland price — per barrel	$50.45	$43.34	$7.11	16%
Average WTI Cushing price — per barrel	$50.94	$43.32	$7.62	18%
Gas				
Total volume — MMcf	187,468	168,227	19,241	11%
Total volume — MMcf per day	513.6	459.6	54.0	12%
Percentage of total production	45 %	48 %		
Average realized price — per Mcf	$2.76	$2.31	$0.45	19%
Average Henry Hub price — per Mcf	$3.11	$2.46	$0.65	26%
NGL				
Total volume — MBbls	17,374	14,200	3,174	22%
Total volume — MBbls per day	47.6	38.8	8.8	23%
Percentage of total production	25 %	24 %		
Average realized price — per barrel	$21.61	$14.05	$7.56	54%
Total				
Total production — MBOE	69,479	58,765	10,714	18%
Total production — MBOE per day	190.4	160.6	29.8	19%
Average realized price — per BOE	$26.97	$20.78	$6.19	30%

Other Revenues

We transport, process, and market some third-party gas that is associated with our equity gas. We market and sell gas for other working interest owners under short term agreements and may earn a fee for such services. The table below reflects income from third-party gas gathering and processing and our net marketing margin for marketing third-party gas.

Gas Gathering and Marketing (in thousands):	Years Ended December 31, 2017	2016	Variance Between 2017 / 2016
Gas gathering and other	$ 43,751	$ 36,033	$ 7,718
Gas marketing	$ 495	$ 94	$ 401

Fluctuations in revenues from gas gathering and gas marketing activities are a function of increases and decreases in volumes, commodity prices, and gathering rate charges. The increases from 2016 are primarily due to an increase in prices.

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Operating Costs and Expenses

Total operating costs and expenses of $1.17 billion in 2017 were 36% lower than the $1.83 billion incurred in 2016. Most of the decrease resulted from ceiling test impairments of our oil and gas properties of $757.7 million recorded in 2016; we recorded no ceiling test impairments in 2017. Also contributing to the decrease was the net gain on derivative instruments in 2017 compared to a net loss in 2016. Otherwise, all other categories of operating costs and expenses increased in 2017. The following table shows our operating costs and expenses for the years indicated and a discussion of year-over-year differences follows.

	Years Ended December 31,		Variance	Per BOE	
Operating Costs and Expenses (in thousands, except per BOE)	2017	2016	Between 2017 / 2016	2017	2016
Impairment of oil and gas properties	$—	$ 757,670	$ (757,670)	N/A	N/A
Depreciation, depletion, and amortization	446,031	392,348	53,683	$6.42	$6.68
Asset retirement obligation	15,624	7,828	7,796	$0.22	$0.13
Production	262,180	232,002	30,178	$3.77	$3.95
Transportation, processing, and other operating	231,640	190,725	40,915	$3.33	$3.25
Gas gathering and other	35,840	31,785	4,055	$0.52	$0.54
Taxes other than income	89,864	61,946	27,918	$1.29	$1.05
General and administrative	79,996	73,901	6,095	$1.15	$1.26
Stock compensation	26,256	24,523	1,733	$0.38	$0.42
(Gain) loss on derivative instruments, net	(21,210)	55,749	(76,959)	N/A	N/A
Other operating expense, net	1,314	755	559	N/A	N/A
	$ 1,167,535	$ 1,829,232	$ (661,697)		

Ceiling Test Impairment

We use the full cost method of accounting for our oil and gas operations. Accounting rules require us to perform a quarterly ceiling test calculation to test our capitalized oil and gas property costs for possible impairment. If the net capitalized cost of our oil and gas properties, as adjusted for income taxes, exceeds the ceiling limitation, the excess is charged to expense. The ceiling limitation is equal to the sum of: (i) the present value discounted at 10% of estimated future net revenues from proved reserves, (ii) the cost of properties not being amortized, and (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, as adjusted for income taxes. Estimated future net revenues are determined based on trailing twelve-month average commodity prices and estimated proved reserve quantities, operating costs, and capital expenditures.

At each quarter-end date during the year ended December 31, 2017, the net capitalized cost of our oil and gas properties, as adjusted for income taxes, did not exceed the ceiling limitation, and, therefore, we did not recognize a ceiling test impairment during the year. The commodity prices used in the December 31, 2017 ceiling calculation, based on the required trailing twelve-month average prices, were $2.98 per Mcf of gas and $51.34 per barrel of oil. A decline of approximately 19% or more in the value of the ceiling limitation would have resulted in an impairment at December 31, 2017. During the year ended December 31, 2016, we recognized ceiling test impairments totaling $757.7 million ($481.4 million, net of tax). These impairments were primarily the result of decreases in the trailing twelve-month average prices for oil, gas, and NGLs utilized in determining the estimated future net revenues from proved reserves. Because the ceiling calculation uses trailing twelve-month average commodity prices, the effect of increases and decreases in period-over-period prices can significantly impact the ceiling limitation calculation. In addition, other factors that impact the ceiling limitation calculation include, but are not limited to, incremental proved reserves that may be added each period, revisions to previous reserve estimates, capital expenditures, operating costs, depletion expense, and all related tax effects. Depending on fluctuations in these factors, including a decline in prices, we may incur full cost ceiling test impairments in future quarters.

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

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Depreciation, Depletion, and Amortization

Depletion increased by $53.3 million, or 15%, during 2017 as compared to 2016. While prices increased in 2017 from 2016, thus increasing our reserves, so too did our exploration and development expenditures and activities, thus increasing our proved oil and gas properties and future development costs, causing an overall increase in depletion expense. DD&A consisted of the following for the years indicated:

	Years Ended December 31,		Variance	Per BOE	
DD&A Expense (in thousands, except per BOE)	2017	2016	Between 2017 / 2016	2017	2016
Depletion	$ 399,328	$ 346,003	$ 53,325	$5.75	$5.89
Depreciation	46,703	46,345	358	0.67	0.79
	$ 446,031	$ 392,348	$ 53,683	$6.42	$6.68

Asset Retirement Obligation

Asset retirement obligation expense is typically primarily comprised of accretion expense. Asset retirement obligation expense includes $10.5 million in 2017 for the estimated liability to decommission two offshore properties in the Gulf of Mexico in which we were a prior lessee. See the “2018 Compared to 2017” section above for more information regarding this matter.

Production

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

	Years Ended December 31,		Variance	Per BOE	
Production Expense (in thousands, except per BOE)	2017	2016	Between 2017 / 2016	2017	2016
Lease operating expense	$ 215,148	$ 189,291	$ 25,857	$3.10	$3.22
Workover expense	47,032	42,711	4,321	0.67	0.73
	$ 262,180	$ 232,002	$ 30,178	$3.77	$3.95

Due to increased daily production in 2017, we reduced our per unit lease operating expense by 4% from 2016. On an absolute basis, lease operating expense in 2017 increased 14%, or $25.9 million, compared to 2016. The increase was primarily caused by: (i) increased saltwater disposal costs primarily attributed to the addition of new wells and recompleted wells, (ii) increased labor costs primarily due to additional employees and salary and bonus increases, (iii) increased equipment maintenance costs, primarily the result of the addition of new wells, (iv) increased gas lift and fuel compression costs, and (v) increased chemicals and treating costs.

Workover expense increased by 10%, or $4.3 million, during 2017 as compared to 2016. During 2017, we had costlier major well workover projects than during 2016, which increased expense. This increase was partially offset by the receipt of partial insurance proceeds during 2017 related to a flooding event in 2015 and the subsequent remediation and repairs, the bulk of which took place in 2016. Generally, workover costs will fluctuate based on the amount of maintenance and remedial activity required during the period.

Transportation, Processing, and Other Operating

Transportation, processing, and other operating costs in 2017 were 21%, or $40.9 million, higher than in 2016. This increase was primarily due to increased production volumes and, to a lesser extent, increased transportation and processing rates in 2017 as compared to 2016.

Gas Gathering and Other

Gas gathering and other in 2017 was 13%, or $4.1 million, higher than in 2016. This increase was primarily due to higher product costs associated with processing third-party production due to higher commodity prices. These increased product costs were offset by increases in associated revenue.

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Taxes Other than Income

In 2017, taxes other than income increased 45%, or $27.9 million, from 2016. This increase was primarily due to the increase in revenue seen between the comparable periods. Taxes other than income were 4.8% and 5.1% of production revenues for 2017 and 2016, respectively. The percentage decreased from 2016 due to the approval of reduced tax rates on several of our high-cost gas wells in Texas and, as part of that process, approved severance tax refunds of $9.1 million.

General and Administrative

G&A costs consisted of the following:

General and Administrative Expense (in thousands):	Years Ended December 31, 2017	2016	Variance Between 2017 / 2016
Gross G&A	$ 156,389	$ 146,432	$ 9,957
Less amounts capitalized to oil and gas properties	(76,393)	(72,531)	(3,862)
G&A expense	$ 79,996	$ 73,901	$ 6,095

The percentage of gross G&A capitalized was 49% and 50% during 2017 and 2016, respectively. G&A expense during 2017 was 8%, or $6.1 million, higher than during 2016. This increase is primarily due to the following increases: (i) other employee compensation, primarily due to increased incentive bonus expense, (ii) insurance, (iii) consulting, (iv) salaries and wages, due to additional employees and salary increases, and (v) charitable donations. These increases were partially offset by decreased severance expense due to a voluntary early retirement incentive program, which included severance pay, that was offered to certain employees during 2016.

Stock Compensation

We recognized stock-based compensation cost as follows:

Stock Compensation Expense (in thousands):	Years Ended December 31, 2017	2016	Variance Between 2017 / 2016
Restricted stock awards:			
Performance stock awards	$ 26,020	$ 24,183	$ 1,837
Service-based stock awards	19,746	18,391	1,355
	45,766	42,574	3,192
Stock option awards	2,599	2,565	34
Total stock compensation cost	48,365	45,139	3,226
Less amounts capitalized to oil and gas properties	(22,109)	(20,616)	(1,493)
Stock compensation expense	$ 26,256	$ 24,523	$ 1,733

Periodic stock compensation expense will fluctuate based on the grant date fair value of awards, the number of awards, the requisite service period of the awards, employee forfeitures, and the timing of the awards. The increase in total stock compensation cost in 2017 as compared to 2016 is primarily due to awards granted either during or subsequent to 2016. These increases were partially offset by awards vesting prior to or during 2017.

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(Gain) Loss on Derivative Instruments, Net

The following table presents the components of (Gain) loss on derivative instruments, net for the periods indicated. See Note 4 to the Consolidated Financial Statements for additional information regarding our derivative instruments.

(Gain) Loss on Derivative Instruments, Net (in thousands):	Years Ended December 31, 2017	2016	Variance Between 2017 / 2016
Decrease (increase) in fair value of derivative instruments, net:			
Gas contracts	$ (40,226)	$ 27,462	$ (67,688)
Oil contracts	17,383	35,724	(18,341)
	(22,843)	63,186	(86,029)
Cash (receipts) payments on derivative instruments, net:			
Gas contracts	(4,557)	(6,467)	1,910
Oil contracts	6,190	(970)	7,160
	1,633	(7,437)	9,070
(Gain) loss on derivative instruments, net	$ (21,210)	$ 55,749	$ (76,959)

Other Income and Expense

Other Income and Expense (in thousands):	Years Ended December 31, 2017	2016	Variance Between 2017 / 2016
Interest expense	$ 74,821	$ 83,272	$ (8,451)
Capitalized interest	(22,948)	(21,248)	(1,700)
Loss on early extinguishment of debt	28,187	—	28,187
Other, net	(11,342)	(10,707)	(635)
	$ 68,718	$ 51,317	$ 17,401

The decrease in interest expense in 2017 as compared to 2016 was due to the completion of a tender offer and redemption of $750 million 5.875% senior notes and the issuance of $750 million 3.90% senior notes, which occurred during the second quarter of 2017. The $28.2 million loss on early extinguishment of debt incurred during 2017 was also associated with the debt tender offer and redemption. The loss was composed primarily of tender and redemption premiums of $22.6 million and the write-off of $5.3 million of unamortized debt issuance costs. The original maturity date of the 5.875% notes was May 1, 2022.

There were higher capitalized costs subject to interest capitalization in 2017 as compared to 2016 due to our increased capitalized expenditures. However, the impact of the increase in capitalized interest was largely offset by the lower interest rate on borrowings outstanding due to the replacement of our 5.875% notes with 3.90% notes in the second quarter of 2017.

Other, net includes interest income of $5.4 million and $3.7 million in 2017 and 2016, respectively. Interest rates were raised once at the end of 2016 and three times in 2017, increasing our interest income earned on our short-term investments. Other components of Other, net consist of miscellaneous income and expense items that vary from period to period, including gain or loss related to the sale or value of oil and gas well equipment and supplies, gain or loss on miscellaneous asset sales, and income and expense associated with other non-operating activities.

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Income Tax Expense (Benefit)

The components of Income Tax Expense (Benefit) were as follows:

Income Tax Expense (Benefit) (in thousands):	Years Ended December 31, 2017	2016	Variance Between 2017 / 2016
Current tax benefit	$ (2,812)	$ (1,115)	$ (1,697)
Deferred tax expense (benefit)	190,479	(213,286)	403,765
	$ 187,667	$ (214,401)	$ 402,068
Combined federal and state effective income tax rate	27.5 %	34.4 %	

On December 22, 2017, the United States enacted H.R.1 (Public Law 115-97), commonly referred to as the Tax Cuts and Jobs Act or U.S. Tax Reform. We remeasured the deferred tax assets and liabilities as of December 31, 2017 to reflect the reduction in the U.S. income tax rate from 35% to 21% for years after 2017 and, as a result of this remeasurement, we recorded an income tax benefit of $61.1 million and a corresponding $61.1 million decrease in the net deferred tax liabilities as of December 31, 2017. See the “2018 Compared to 2017” section above for more information regarding this matter.

Our combined federal and state effective tax rates, as shown above, differed from the statutory rate at the time of 35% primarily due to state income taxes, non-deductible expenses, revisions, and the impact of changes in tax law. See Note 9 to the Consolidated Financial Statements for further information regarding our income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We strive to maintain an adequate liquidity level to address volatility and risk. Sources of liquidity include our cash flow from operations, cash on hand, available borrowing capacity under our revolving credit facility, proceeds from sales of non-core assets, including our Ward County asset sale that closed in August 2018, and, from time to time, public financings based on our monitoring of capital markets and our balance sheet.

Our liquidity is highly dependent on prices we receive for the oil, gas, and NGLs we produce. Prices we receive are determined by prevailing market conditions and greatly influence our revenue, cash flow, profitability, access to capital, and future rate of growth. See RESULTS OF OPERATIONS Revenues above for further information regarding the impact realized prices have had on our 2018 earnings.

In connection with the expected closing of our acquisition of Resolute, we anticipate utilizing cash on hand to fund the cash portion of the merger consideration, acquisition fees and expenses, and the repayment of the outstanding balance on Resolute’s revolving credit facility, all of which we estimate will be between $600 million and $630 million. In addition, we intend to redeem and repay the $600 million senior notes of Resolute. This transaction is expected to close in the first quarter of 2019.

We deal with volatility in commodity prices primarily by maintaining flexibility in our capital investment program. We have a balanced and abundant drilling inventory and limited long-term commitments, which enables us to respond quickly to industry volatility. Based on current economic conditions, and assuming the successful acquisition of Resolute, our 2019 exploration and development (“E&D”) expenditures are projected to range from $1.35 billion to $1.45 billion. Investments in gathering, processing, and other infrastructure are expected to be an additional $60 million to $70 million for 2019. See Capital Expenditures below for information regarding our 2018 E&D

activities.

We periodically use derivative instruments to mitigate volatility in commodity prices. At December 31, 2018, we had derivative contracts covering a portion of our 2019 and 2020 production. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our derivative positions from current levels. See Note 4 to the Consolidated Financial Statements for information regarding our derivative instruments.

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We believe our conservative use of leverage, strong balance sheet, and hedging activities will mitigate our exposure to lower prices. Cash and cash equivalents at December 31, 2018 were $800.7 million. At December 31, 2018, our long-term debt consisted of $1.50 billion of senior unsecured notes, with $750 million 4.375% notes due in 2024 and $750 million 3.90% notes due in 2027. At December 31, 2018, we had no borrowings and $2.5 million in letters of credit outstanding under our credit facility, leaving an unused borrowing availability of $997.5 million. See Long-Term Debt below for more information regarding our debt.

Our debt to total capitalization ratio at December 31, 2018 was 31%, down from 37% at December 31, 2017. This ratio is calculated by dividing the principal amount of long-term debt by the sum of (i) the principal amount of long-term debt and (ii) total stockholders' equity, with all numbers coming directly from the Consolidated Balance Sheet. Management uses this ratio as one indicator of our financial condition and believes professional research analysts and rating agencies use this ratio for this purpose and to compare our financial condition to other companies' financial conditions.

We expect our operating cash flow and other capital resources to be adequate to meet our needs for planned capital expenditures, working capital, debt service, and dividends declared for the next twelve months.

Analysis of Cash Flow Changes

The following table presents the totals of the major cash flow classification categories from our Consolidated Statements of Cash Flows for the periods indicated.

	Years Ended December 31,		
(in thousands)	2018	2017	2016
Net cash provided by operating activities	$1,550,994	$1,096,564	$625,849
Net cash used by investing activities	$(1,085,618)	$(1,265,897)	$(692,410)
Net cash used by financing activities	$(65,244)	$(83,009)	$(59,945)

Net cash provided by operating activities in 2018 was $1.55 billion, up $454.4 million, or 41%, from $1.10 billion in 2017. The increase was primarily a result of higher revenues due to higher production volumes and realized oil and NGL prices in 2018. Also contributing to the increase was a decreased investment in working capital, primarily caused by the timing of cash receipts of accounts receivable. These increases were partially offset by increased net operating expenses, primarily production expense and taxes other than income, and increased cash outflows for settlements of derivative instruments. Net cash provided by operating activities in 2017 was $1.10 billion, up $470.7 million, or 75%, from $625.8 million in 2016. The increase was primarily a result of higher revenue due to higher realized prices and production volumes in 2017. This increase was partially offset by increased operating expenses and an increased investment in working capital. See RESULTS OF OPERATIONS above for more information regarding year-over-year changes in revenue and operating expenses.

In 2018, net cash used by investing activities was $1.09 billion, compared to $1.27 billion and $692.4 million in 2017 and 2016, respectively. The majority of our cash flows used by investing activities are for E&D capital expenditures, which, as reflected in the statements of cash flows, were $1.57 billion, $1.23 billion, and $699.6 million in 2018, 2017, and 2016, respectively. Our other capital expenditures, which are primarily for our midstream assets, were $103.5 million, $45.4 million, and $22.2 million in 2018, 2017, and 2016, respectively. In 2018, cash outflows for capital expenditures were partially offset by proceeds from asset sales of $584.4 million, which includes $534.6 million in net cash proceeds from the August 2018 divestiture of oil and gas properties principally located in Ward County, Texas for which the final cash settlement, which will reflect customary post-closing adjustments, is scheduled to occur by the end of first quarter 2019. Net cash proceeds from other asset sales totaled $49.9 million, $12.6 million, and $29.4 million in 2018, 2017, and 2016, respectively. These asset sales are primarily for the divestiture of non-core oil and gas properties.

Net cash used by financing activities was $65.2 million, $83.0 million, and $59.9 million in 2018, 2017, and 2016, respectively. All years include the payment of dividends, the payment of income tax withholdings made on behalf of our employees upon the net settlement of employee stock awards, and the receipt of proceeds from stock option exercises. Dividends paid were $55.2 million, $30.5 million, and $38.0 million in 2018, 2017, and 2016, respectively. During the years presented, we have declared cash dividends quarterly, paying them in the following quarter. We paid dividends totaling $0.58 per share, $0.32 per share, and $0.40 per share in 2018, 2017, and 2016, respectively. We paid employee income tax withholdings on the net settlement of stock awards totaling $12.1 million,

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$21.7 million, and $26.6 million in 2018, 2017, and 2016, respectively. Cash proceeds received from stock option exercises were $2.2 million, $0.4 million, and $4.8 million, in 2018, 2017, and 2016, respectively. Additionally, 2017 included: (i) the early extinguishment of $750 million 5.875% senior notes, which included $22.6 million of tender and redemption premiums and (ii) the issuance of $750 million 3.90% senior notes at 99.748% of par for proceeds of $748.1 million, paying $6.3 million in underwriting, financing, and other costs.

Capital Expenditures

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

	Years Ended December 31,		
(in thousands)	2018	2017	2016
Acquisitions:			
Proved	$62	$938	$2,678
Unproved	26,216	6,853	11,865
	26,278	7,791	14,543
Exploration and development:			
Land and seismic	82,791	140,516	61,870
Exploration and development	1,487,453	1,140,548	672,882
	1,570,244	1,281,064	734,752
Property sales	(581,799)	(11,680)	(24,687)
	$1,014,723	$1,277,175	$724,608

Amounts in the table above are presented on an accrual basis. Oil and gas capital expenditures and sales of oil and gas assets in the Consolidated Statements of Cash Flows reflect capital expenditures on a cash basis, when payments are made and proceeds received.

We increased our 2018 E&D expenditures 23% to $1.57 billion compared to $1.28 billion in 2017. Approximately 70% of our 2018 E&D expenditures were in the Permian Basin and 30% were in the Mid-Continent. During 2018, we completed or participated in the completion of 349 gross (122.1 net) wells, of which we operated 146 gross (105.8 net) wells. See Items 1 and 2 of this report for further information regarding our oil and gas properties.

Approximately 85% of our planned 2019 E&D capital investment of $1.35 billion to $1.45 billion is expected to be invested in the Permian Basin and most of the remainder in the Mid-Continent.

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

We intend to fund our 2019 capital program and the acquisition of Resolute with cash flow from our operating activities, cash on hand, and borrowings under our credit facility. Sales of non-core assets and possible capital markets transactions may also be used to supplement funding of capital expenditures and acquisitions. The timing of capital expenditures and the receipt of cash flows do not necessarily match, which may cause us to borrow and repay funds under our credit facility from time-to-time. See Long-Term Debt—Bank Debt below for further information regarding our credit facility.

On November 18, 2018, we entered into an agreement and plan of merger to acquire Resolute in a cash and stock transaction valued at a total purchase price of approximately $1.6 billion, including the assumption of Resolute's long-term debt, which was $710 million as of September 30, 2018. Under the terms of the agreement, Resolute shareholders will have the right to receive 0.3943 shares of Cimarex common stock, $35.00 per share in cash, or a combination of $14.00 per share in cash and 0.2366 shares of Cimarex common stock. The amount of stock and cash is subject to proration for a total stock and cash mix of 60% and 40%, respectively. Assuming completion of the acquisition, Resolute's former stockholders will own approximately 6.4% of our outstanding common stock based on shares outstanding for both companies as of January 18, 2019. The cash portion of the merger consideration, acquisition fees and expenses, and the repayment of the outstanding balance on Resolute's revolving credit facility, all of which

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are estimated to be between $600 million and $630 million, are expected to be funded through cash on hand. In addition, we intend to redeem and repay the $600 million senior notes of Resolute. This acquisition will expand Cimarex's footprint in Reeves County, Texas by 21,100 net acres that are complementary to our existing Reeves County position. The transaction, which is expected to be completed by the end of the first quarter 2019, is subject to the approval of Resolute shareholders and the satisfaction of certain regulatory approvals and other customary closing conditions.

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. While we expect current pending legislation or regulations to increase the cost of business, we do not anticipate that we will be required to expend amounts that will have a material adverse effect on our financial position or operations, nor are we aware of any pending regulatory changes that would have a material impact, based on current laws and regulations. However, compliance with new legislation or regulations could increase our costs or adversely affect demand for oil or gas and result in a material adverse effect on our financial position or operations. See Item 1A RISK FACTORS for a description of risks related to current and potential future environmental and safety regulations and requirements that could adversely affect our operations and financial condition.

Long-Term Debt

Long-term debt at December 31, 2018 and 2017 consisted of the following:

(in thousands)	December 31, 2018			December 31, 2017		
	Principal	Unamortized Debt Issuance Costs and Discount (1)	Long-term Debt, net	Principal	Unamortized Debt Issuance Costs and Discount (1)	Long-term Debt, net
4.375% Senior Notes	$750,000	$ (4,439)	$745,561	$750,000	$ (5,383)	$744,617
3.90% Senior Notes	750,000	(7,007)	742,993	750,000	(7,697)	742,303
Total long-term debt	$1,500,000	$ (11,446)	$1,488,554	$1,500,000	$ (13,080)	$1,486,920

(1) At December 31, 2018, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.4 million and $1.6 million, respectively. At December 31, 2017, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.9 million and $1.8 million, respectively. The 4.375% notes were issued at par.

Bank Debt

In October 2015, we entered into a senior unsecured revolving credit facility ("Credit Facility") with an aggregate commitment of $1.0 billion, which matures October 16, 2020. There is no borrowing base subject to the discretion of the lenders based on the value of our proved reserves under the Credit Facility. As of December 31, 2018, we had no bank borrowings outstanding under the Credit Facility, but did have letters of credit of $2.5 million outstanding, leaving an unused borrowing availability of $997.5 million.

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

The Credit Facility contains representations, warranties, covenants, and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a defined total debt-to-capital ratio of no greater than 65%. As of December 31, 2018, we were in compliance with all of the financial and non-financial covenants.

At December 31, 2018 and 2017, we had $2.2 million and $3.4 million, respectively, of unamortized debt issuance costs associated with our Credit Facility that were recorded as deferred assets and included in “Other assets” in our balance sheets. The costs are being amortized to interest expense ratably over the life of the Credit Facility.

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On February 5, 2019, we entered into an Amended and Restated Credit Agreement. Among other things, the amended and restated credit facility increases the aggregate commitment to $1.25 billion with an option to increase the commitment to $1.5 billion, and extends the maturity date to February 5, 2024.

Senior Notes

On April 10, 2017, we completed a cash tender offer to purchase any of our 5.875% senior unsecured notes for cash consideration of $1,031.67 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date, with $253.5 million aggregate principal amount of the notes validly tendered. We settled these tendered notes for $268.1 million, including accrued interest. On May 12, 2017, we completed a redemption of the 5.875% notes remaining outstanding for $1,029.38 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the redemption date, settling the notes for $512.0 million, including accrued interest. We recognized a loss on early extinguishment of debt related to these transactions of $28.2 million, composed primarily of tender and redemption premiums of $22.6 million and the write-off of $5.3 million of unamortized debt issuance costs. The original maturity date of the 5.875% notes was May 1, 2022.

On April 10, 2017, we issued $750 million aggregate principal amount of 3.90% senior unsecured notes due May 15, 2027 at 99.748% of par to yield 3.93% per annum. We received $741.8 million in net cash proceeds, after deducting underwriters' fees, discount, and debt issuance costs. The notes bear an annual interest rate of 3.90% and interest is payable semiannually on May 15 and November 15, with the first payment occurring November 15, 2017. Along with cash on hand, we used the proceeds to fund the settlement of the tendered and redeemed 5.875% notes.

In June 2014, we issued $750 million aggregate principal amount of 4.375% senior unsecured notes at par. These notes are due June 1, 2024 and interest is payable semiannually on June 1 and December 1.

Each of our senior unsecured notes is governed by an indenture containing certain covenants, events of default, and other restrictive provisions with which we were in compliance as of December 31, 2018. The effective interest rate on the 4.375% notes and the 3.90% notes, including the amortization of debt issuance costs and discount, as applicable, is 4.50% and 4.01%, respectively.

Working Capital Analysis

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

At December 31, 2018, we had working capital of $715.4 million, an increase of $459.4 million, or 179%, compared to working capital of $256.1 million at December 31, 2017.

Working capital increases consisted primarily of the following:

- Cash and cash equivalents increased $400.1 million. This is primarily due to the receipt of $534.6 million in net cash proceeds from the August 2018 divestiture of oil and gas properties principally located in Ward County, Texas.
- Our net current derivative instruments increased in value by $101.2 million from a net current liability at December 31, 2017 to a net current asset at December 31, 2018.

Working capital decreases consisted primarily of the following:

- Operations-related accounts payable and accrued liabilities increased $33.6 million.
- Accrued liabilities related to our E&D expenditures increased $8.9 million.

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Dividends

A quarterly cash dividend has been paid to stockholders every quarter since the first quarter of 2006. In February 2016, the quarterly dividend declared was decreased from $0.16 per share to $0.08 per share, where it remained through the fourth quarter of 2017. In the first and second quarters of 2018, we declared dividends of $0.16 per share and in the third and fourth quarters of 2018, we declared dividends of $0.18 per share. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors. See Note 2 to the Consolidated Financial Statements for further information regarding dividends.

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, 2018, our material off-balance sheet arrangements consisted of operating lease agreements, which are included in the table below.

Contractual Obligations and Material Commitments

At December 31, 2018, we had the following contractual obligations and material commitments:

	Payments Due by Period				
Contractual obligations (in thousands):	Total	1/1/19 - 12/31/19	1/1/20 - 12/31/21	1/1/22 - 12/31/23	1/1/24 and Thereafter
Long-term debt-principal (1)	$1,500,000	$—	$—	$—	$1,500,000
Long-term debt-interest (1)	429,094	60,844	124,125	124,125	120,000
Operating leases (2)	109,832	23,007	43,431	22,563	20,831
Unconditional purchase obligations (3)	64,593	24,263	27,967	6,900	5,463
Derivative liabilities	29,894	27,627	2,267	—	—
Asset retirement obligation (4)	166,904	14,146	— (4)	— (4)	— (4)
Other long-term liabilities (5)	36,926	1,390	2,903	5,048	27,585
	$2,337,243	$151,277	$200,693	$158,636	$1,673,879

(1) The interest payments presented above include the accrued interest payable on our long-term debt as of December 31, 2018 as well as future payments calculated using the long-term debt's fixed rates, stated maturity dates, and principal amounts outstanding as of December 31, 2018. See Note 3 to the Consolidated Financial Statements for additional information regarding our debt.

(2) Operating leases include various lease commitments for commercial real estate, which consists primarily of office space, and compressor equipment.

(3) Of the total Unconditional purchase obligations, $36.0 million represents obligations for the purchase of sand for well completions and $27.8 million represents obligations for firm transportation agreements for gas pipeline capacity.

(4) We have excluded the presentation of the timing of the cash flows associated with our long-term asset retirement obligations because we cannot make a reasonably reliable estimate of the future period of cash settlement. The long-term asset retirement obligation is included in the total asset retirement obligation presented.

(5) Other long-term liabilities include contractual obligations associated with our employee supplemental savings plan, gas balancing liabilities, and other miscellaneous liabilities. All of these liabilities are accrued on our Consolidated Balance Sheet. The current portion associated with these long-term liabilities is also presented in the table above.

The following discusses various commercial commitments that we have made that may include potential future cash payments if we fail to meet various performance obligations. These are not reflected in the table above.

At December 31, 2018, we had estimated commitments of approximately: (i) $498.3 million to finish drilling, completing, or performing other work on wells and various other infrastructure projects in progress and (ii) $24.9 million to finish gathering system construction in progress.

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At December 31, 2018, we had firm sales contracts to deliver approximately 316.9 Bcf of natural gas over the next 6.1 years. If we do not deliver this gas, our estimated financial commitment, calculated using the January 2019 index price, would be approximately $814.7 million. The value of this commitment will fluctuate due to price volatility and actual volumes delivered. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these volumetric obligations.

In connection with gas gathering and processing agreements, we have volume commitments over the next 9.0 years. If we do not deliver the committed gas or NGLs, as the case may be, the estimated maximum amount that would be payable under these commitments, calculated as of December 31, 2018, would be approximately $336.0 million. However, we believe no financial commitment will be due based on our current proved reserves and production levels from which we can fulfill these volumetric obligations.

We have minimum volume delivery commitments associated with agreements to reimburse connection costs to various pipelines. If we do not deliver this gas, the estimated maximum amount that would be payable under these commitments, calculated as of December 31, 2018, would be approximately $57.3 million. Of this total, we have accrued a liability of $2.5 million representing the estimated amount we will have to pay due to insufficient forecasted volumes at particular connection points.

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

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses. We analyze and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Our significant accounting policies are described in Note 1 to our Consolidated Financial Statements. 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 2018, 15% of our total proved reserves are categorized as proved undeveloped reserves. 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 INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED) in Item 8 for additional reserve data.

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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 acquisition, 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. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Under the full cost method of accounting, we are required to perform quarterly ceiling test calculations to test our oil and gas properties for possible impairment. If the net capitalized cost of our oil and gas properties, as adjusted for income taxes, exceeds the ceiling limitation, the excess is charged to expense. The ceiling limitation is equal to the sum of: (i) the present value discounted at 10% of estimated future net revenues from proved reserves, (ii) the cost of properties not being amortized, and (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, as adjusted for income taxes. We currently do not have any unproven properties that are being amortized. Estimated future net revenues are determined based on trailing twelve-month average commodity prices and estimated proved reserve quantities, operating costs, and capital expenditures.

The quarterly ceiling test is primarily impacted by commodity prices, changes in estimated reserve quantities, reserves produced, overall exploration and development costs, depletion expense, and deferred taxes. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur full cost ceiling test impairments in future quarters. The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet. Any impairment of oil and gas properties is not reversible at a later date.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement costs, 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. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors.

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. Numerous judgments and assumptions are inherent in this assessment, including the determination of future taxable income, which is affected by factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance.

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

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Recently Issued Accounting Standards

See Note 1 to the Consolidated Financial Statements for a discussion of recent accounting pronouncements and their anticipated effect on our business.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk including the risk of loss arising from adverse changes in commodity prices and interest rates.

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. During 2018, our total production revenue was comprised of 61% oil sales, 18% gas sales, and 21% NGL sales. The following table shows how hypothetical changes in the realized prices we receive for our commodity sales would have impacted revenue for the periods indicated. See MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Market Conditions for further information regarding prices.

	Change in Realized Price	Impact on Revenue Year Ended December 31, 2018 (in thousands)
Oil	± $1.00 per barrel	± $24,710
Gas	± $0.10 per Mcf	± $20,584
NGL	± $1.00 per barrel	± $21,994
		± $67,288

We periodically enter into derivative contracts to hedge a portion of our price risk associated with our future oil and gas production. At December 31, 2018, we had oil and gas derivatives covering a portion of our 2019 and 2020 production, which were recorded as current and non-current assets and liabilities. At December 31, 2018, these derivatives had a gross asset fair value of $111.2 million and a gross liability fair value of $29.9 million. See Note 4 to the Consolidated Financial Statements for additional information regarding our derivative instruments.

While these contracts limit the downside risk of adverse price movements, they may also limit future cash flow from favorable price movements. The following table shows how hypothetical changes in the forward prices used to calculate the fair value of our derivatives would have impacted the fair value as of December 31, 2018.

	Change in Forward Price	Impact on Fair Value December 31, 2018 (in thousands)
Oil	-$1.00	$ 7,718
Oil	+$1.00	$ (7,539)
Gas	-$0.10	$ 5,670

Gas +$0.10	$ (5,606)

Interest Rate Risk

At December 31, 2018, our long-term debt consisted of $750 million of 4.375% senior unsecured notes that will mature on June 1, 2024 and $750 million of 3.90% senior unsecured notes that will mature on May 15, 2027. Because all of our outstanding long-term debt is at a fixed rate, we consider our interest rate exposure to be minimal. See Note 3 and Note 5 to the Consolidated Financial Statements for additional information regarding our 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 Stockholders and Board of Directors
Cimarex Energy Co.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Cimarex Energy Co. and subsidiaries (“the Company”) as of December 31, 2018 and 2017, the related consolidated statements of operations and comprehensive income (loss), stockholders’ equity, and cash flows for each of the years in the three year period ended December 31, 2018, and the related notes (collectively, “the consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2018, 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) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 20, 2019 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

KPMG LLP

We have served as the Company’s auditor since 2002.

Denver, Colorado
February 20, 2019

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CIMAREX ENERGY CO.
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share information)

	December 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$800,666	$400,534
Accounts receivable, net of allowance:		
Trade	122,065	100,356
Oil and gas sales	315,063	344,552
Gas gathering, processing, and marketing	17,072	15,266
Oil and gas well equipment and supplies	55,553	49,722
Derivative instruments	101,939	15,151
Prepaid expenses	7,554	8,518
Other current assets	4,227	1,536
Total current assets	1,424,139	935,635
Oil and gas properties at cost, using the full cost method of accounting:		
Proved properties	18,566,757	17,513,460
Unproved properties and properties under development, not being amortized	436,325	476,903
	19,003,082	17,990,363
Less—accumulated depreciation, depletion, amortization, and impairment	(15,287,752)	(14,748,833)
Net oil and gas properties	3,715,330	3,241,530
Fixed assets, net of accumulated depreciation of $324,631 and $290,114, respectively	257,686	210,922
Goodwill	620,232	620,232
Derivative instruments	9,246	2,086
Other assets	35,451	32,234
	$6,062,084	$5,042,639
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable:		
Trade	$76,927	$68,883
Gas gathering, processing, and marketing	29,887	29,503
Accrued liabilities:		
Exploration and development	124,674	115,762
Taxes other than income	33,622	23,687
Other	221,159	212,400
Derivative instruments	27,627	42,066
Revenue payable	194,811	187,273
Total current liabilities	708,707	679,574
Long-term debt:		
Principal	1,500,000	1,500,000
Less—unamortized debt issuance costs and discount	(11,446)	(13,080)
Long-term debt, net	1,488,554	1,486,920
Deferred income taxes	334,473	101,618
Asset retirement obligation	152,758	158,421
Derivative instruments	2,267	4,268

Other liabilities	45,539	43,560
Total liabilities	2,732,298	2,474,361
Commitments and contingencies (Note 10)		
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, 95,755,797 and 95,437,434 shares issued, respectively	958	954
Additional paid-in capital	2,785,188	2,764,384
Retained earnings (accumulated deficit)	542,885	(199,259)
Accumulated other comprehensive income	755	2,199
Total stockholders’ equity	3,329,786	2,568,278
	$6,062,084	$5,042,639

See accompanying notes to Consolidated Financial Statements.

CIMAREX ENERGY CO.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
(in thousands, except per share information)

	Years Ended December 31,		
	2018	2017	2016
Revenues:			
Oil sales	$1,398,813	$981,646	$632,934
Gas and NGL sales	898,832	892,357	588,284
Gas gathering and other	41,180	43,751	36,033
Gas marketing	192	495	94
	2,339,017	1,918,249	1,257,345
Costs and expenses:			
Impairment of oil and gas properties	—	—	757,670
Depreciation, depletion, and amortization	590,473	446,031	392,348
Asset retirement obligation	7,142	15,624	7,828
Production	293,213	262,180	232,002
Transportation, processing, and other operating	200,802	231,640	190,725
Gas gathering and other	41,964	35,840	31,785
Taxes other than income	125,169	89,864	61,946
General and administrative	80,850	79,996	73,901
Stock compensation	22,895	26,256	24,523
(Gain) loss on derivative instruments, net	(85,959)	(21,210)	55,749
Other operating expense, net	15,500	1,314	755
	1,292,049	1,167,535	1,829,232
Operating income (loss)	1,046,968	750,714	(571,887)
Other (income) and expense:			
Interest expense	68,224	74,821	83,272
Capitalized interest	(20,855)	(22,948)	(21,248)
Loss on early extinguishment of debt	—	28,187	—
Other, net	(22,908)	(11,342)	(10,707)
Income (loss) before income tax	1,022,507	681,996	(623,204)
Income tax expense (benefit)	230,656	187,667	(214,401)
Net income (loss)	$791,851	$494,329	$(408,803)
Earnings (loss) per share to common stockholders:			
Basic	$8.32	$5.19	$(4.38)
Diluted	$8.32	$5.19	$(4.38)
Comprehensive income (loss):			
Net income (loss)	$791,851	$494,329	$(408,803)
Other comprehensive income (loss):			
Change in fair value of investments, net of tax of $(425), $106, and $289, respectively	(1,444)	1,254	504
Total comprehensive income (loss)	$790,407	$495,583	$(408,299)

See accompanying notes to Consolidated Financial Statements.

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CIMAREX ENERGY CO.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31,		
	2018	2017	2016
Cash flows from operating activities:			
Net income (loss)	$791,851	$494,329	$(408,803)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Impairment of oil and gas properties	—	—	757,670
Depreciation, depletion, and amortization	590,473	446,031	392,348
Asset retirement obligation	7,142	15,624	7,828
Deferred income taxes	233,280	190,479	(213,286)
Stock compensation	22,895	26,256	24,523
(Gain) loss on derivative instruments, net	(85,959)	(21,210)	55,749
Settlements on derivative instruments	(24,429)	(1,633)	7,437
Loss on early extinguishment of debt	—	28,187	—
Changes in non-current assets and liabilities	(1,779)	1,891	3,867
Other, net	105	5,677	1,805
Changes in operating assets and liabilities:			
Accounts receivable	5,421	(186,157)	(49,340)
Other current assets	(1,957)	(17,931)	20,880
Accounts payable and other current liabilities	13,951	115,021	25,171
Net cash provided by operating activities	1,550,994	1,096,564	625,849
Cash flows from investing activities:			
Oil and gas capital expenditures	(1,566,583)	(1,233,126)	(699,558)
Other capital expenditures	(103,459)	(45,352)	(22,228)
Sales of oil and gas assets	580,652	11,680	21,487
Sales of other assets	3,772	901	7,889
Net cash used by investing activities	(1,085,618)	(1,265,897)	(692,410)
Cash flows from financing activities:			
Borrowings of long-term debt	—	748,110	—
Repayments of long-term debt	—	(750,000)	—
Call premium, financing, and underwriting fees	(100)	(29,312)	(101)
Dividends paid	(55,243)	(30,532)	(38,024)
Employee withholding taxes paid upon the net settlement of equity-classified stock awards	(12,142)	(21,669)	(26,624)
Proceeds from exercise of stock options	2,241	394	4,804
Net cash used by financing activities	(65,244)	(83,009)	(59,945)
Net change in cash and cash equivalents	400,132	(252,342)	(126,506)
Cash and cash equivalents at beginning of period	400,534	652,876	779,382
Cash and cash equivalents at end of period	$800,666	$400,534	$652,876

See accompanying notes to Consolidated Financial Statements.

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CIMAREX ENERGY CO.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance, December 31, 2015	94,821	$ 948	$ 2,762,976	$ (306,008)	$ 441	$ 2,458,357
Dividends paid on stock awards subsequently forfeited	—	—	2	35	—	37
Dividends declared ($0.32 per share)	—	—	(22,805)	(7,583)	—	(30,388)
Net loss	—	—	—	(408,803)	—	(408,803)
Unrealized change in fair value of investments, net of tax	—	—	—	—	504	504
Issuance of restricted stock awards	479	5	(5)	—	—	—
Common stock reacquired and retired	(208)	(3)	(26,622)	—	—	(26,625)
Restricted stock forfeited and retired	(32)	—	—	—	—	—
Exercise of stock options	64	1	4,803	—	—	4,804
Stock-based compensation	—	—	45,103	—	—	45,103
Balance, December 31, 2016	95,124	951	2,763,452	(722,359)	945	2,042,989
Dividends paid on stock awards subsequently forfeited	—	—	11	32	—	43
Dividends declared ($0.32 per share)	—	—	(30,489)	—	—	(30,489)
Net income	—	—	—	494,329	—	494,329
Unrealized change in fair value of investments, net of tax	—	—	—	—	1,254	1,254
Issuance of restricted stock awards	552	5	(5)	—	—	—
Common stock reacquired and retired	(204)	(2)	(21,667)	—	—	(21,669)
Restricted stock forfeited and retired	(41)	—	—	—	—	—
Exercise of stock options	6	—	394	—	—	394
Stock-based compensation	—	—	48,321	—	—	48,321
Cumulative effect adjustment of adopting ASU 2016-09 (Note 6)	—	—	4,393	28,739	—	33,132
Other	—	—	(26)	—	—	(26)
Balance, December 31, 2017	95,437	954	2,764,384	(199,259)	2,199	2,568,278
Dividends paid on stock awards subsequently forfeited	—	—	34	18	—	52
Dividends declared ($0.68 per share)	—	—	(15,196)	(49,725)	—	(64,921)
Net income	—	—	—	791,851	—	791,851
Unrealized change in fair value of investments, net of tax	—	—	—	—	(1,444)	(1,444)
Issuance of restricted stock awards	593	6	(6)	—	—	—
Common stock reacquired and retired	(139)	—	(12,142)	—	—	(12,142)
Restricted stock forfeited or canceled and retired	(168)	(2)	2	—	—	—
Exercise of stock options	33	—	2,241	—	—	2,241
Stock-based compensation	—	—	45,871	—	—	45,871
Balance, December 31, 2018	95,756	$ 958	$ 2,785,188	$ 542,885	$ 755	$ 3,329,786

See accompanying notes to 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. Certain amounts in the prior year financial statements have been reclassified to conform to the 2018 financial statement presentation.

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.

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. Areas of significance requiring the use of management's judgments include the estimation of proved oil and gas reserves used in calculating depletion, the estimation of future net revenues used in computing ceiling test limitations, the estimation of future abandonment obligations used in recording asset retirement obligations, and the assessment of goodwill. Estimates and judgments also are required in determining allowances for doubtful accounts, impairments of unproved properties and other assets, valuation of deferred tax assets, fair value measurements, and contingencies. We analyze our estimates and base them 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.

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.

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 and net realizable value, where net realizable value is based on estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. Declines in the price of oil and gas well equipment and supplies in future periods could cause us to recognize impairments on these assets. An impairment would not affect cash flow from operating activities, but would adversely affect our net income and stockholders' equity.

Oil and Gas Properties

We use the full cost method of accounting for our oil and gas operations. All costs associated with property acquisition, exploration, and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities, and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the acquisition, 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. Expenditures for maintenance and repairs are charged to production expense in the period incurred.

Under the full cost method of accounting, we are required to perform quarterly ceiling test calculations to test our oil and gas properties for possible impairment. If the net capitalized cost of our oil and gas properties, as adjusted for income taxes, exceeds the ceiling limitation, the excess is charged to expense. The ceiling limitation is equal to the sum of: (i) the present value discounted at 10% of estimated future net revenues from proved reserves, (ii) the cost of properties not being amortized, and (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized, as adjusted for income taxes. We currently do not have any unproven properties that are being amortized. Estimated future net revenues are determined based on trailing twelve-month average commodity prices and estimated proved reserve quantities, operating costs, and capital expenditures.

We did not recognize a ceiling test impairment during the years ended December 31, 2018 and 2017 because the net capitalized cost of our oil and gas properties, as adjusted for income taxes, did not exceed the ceiling limitation. At December 31, 2018, a decline in the value of the ceiling limitation of approximately 24% or more would have resulted in an impairment. For the year ended December 31, 2016, full year impairments totaled $757.7 million ($481.4 million, net of tax). These impairments resulted primarily from the impact of decreases in the trailing twelve-month average prices for oil, gas, and NGLs utilized in determining the future net revenues from proved reserves. The quarterly ceiling test is primarily impacted by commodity prices, changes in estimated reserve quantities, reserves produced, overall exploration and development costs, depletion expense, and deferred taxes. If pricing conditions decline, or if there is a negative impact on one or more of the other components of the calculation, we may incur full cost ceiling test impairments in future quarters. The calculated ceiling limitation is not intended to be indicative of the fair market value of our proved reserves or future results. Impairment charges do not affect cash flow from operating activities, but do adversely affect our net income and various components of our balance sheet. Any impairment of oil and gas properties is not reversible at a later date.

Depletion of proved oil and gas properties is computed on the units-of-production method, whereby capitalized costs, including future development costs and asset retirement costs, 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. Significant unproved properties are evaluated individually. Unproved properties that are not considered individually significant are aggregated for evaluation purposes and related costs are transferred to the costs to be amortized quarterly based on the application of historical factors.

Fixed Assets

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. In performing the goodwill test, we compare the fair value of our reporting unit with its carrying amount. If the carrying amount of the reporting unit were to exceed its fair value, an impairment charge would be recognized in the amount of this excess, limited to the total amount of goodwill allocated to that reporting unit. We evaluate our goodwill for impairment in the fourth quarter of each year and whenever events or changes in circumstances indicate the possibility that goodwill may be impaired. Based upon our assessment as of October 31, 2018, goodwill was not impaired. It is possible that goodwill could become impaired in the future if commodity prices or other economic factors become unfavorable.

Revenue Recognition

Oil, Gas, and NGL Sales

Effective January 1, 2018, we adopted the provisions of Accounting Standards Codification 606, Revenue from Contracts with Customers (“ASC 606”), utilizing the modified retrospective approach, which we applied to contracts that were not completed as of that date. Because we utilized the modified retrospective approach, there was no impact to prior periods’ reported amounts. Application of ASC 606 has no impact on our net income or cash flows from operations; however, certain costs classified as Transportation, processing, and other operating in the statement of operations under prior accounting standards are now reflected as deductions from revenue under ASC 606. The following table presents the impact on our Oil sales, Gas sales, and NGL sales and on our Transportation, processing, and other operating costs from the application of ASC 606 in the current reporting period:

	Years Ended December 31,				
	2018			2017	2016
(in thousands)	Pre-ASC 606 Adoption	Impact of ASC 606	Post-ASC 606 Adoption	As Reported	As Reported
Oil sales	$1,398,813	$—	$1,398,813	$981,646	$632,934
Gas sales	425,233	(16,482)	408,751	516,936	388,786
NGL sales	518,410	(28,329)	490,081	375,421	199,498
Total oil, gas, and NGL sales	$2,342,456	$(44,811)	$2,297,645	$1,874,003	$1,221,218
Transportation, processing, and other operating costs	$245,613	$(44,811)	$200,802	$231,640	$190,725

Revenue is recognized from the sales of oil, gas, and NGLs when the customer obtains control of the product, when we have no further obligations to perform related to the sale, and when collectability is probable. All of our sales of oil, gas, and NGLs are made under contracts with customers, which typically include variable consideration based on monthly pricing tied to local indices and monthly volumes delivered. The nature of our contracts with customers does not require us to constrain that variable consideration or to estimate the amount of transaction price attributable to future performance obligations for accounting purposes. As of December 31, 2018, we had open contracts with customers with terms of one month to multiple years, as well as “evergreen” contracts that renew on a periodic basis if not canceled by us or the customer. Performance obligations under our contracts with customers are typically satisfied at a point-in-time through monthly delivery of oil, gas, and/or NGLs. Our contracts with customers typically require payment within one month of delivery.

Our gas and NGLs are sold under a limited number of contract structure types common in our industry. Under these contracts the gas and its components, including NGLs, may be sold to a single purchaser or the residue gas and NGLs may be sold to separate purchasers. Regardless of the contract structure type, the terms of these contracts compensate us for the value of the residue gas and NGLs at current market prices for each product, and are disaggregated in the tables above on that basis. Our oil typically is sold at specific delivery points under contract terms that also are common in our industry.

Gas Gathering

When we transport and/or process third-party gas associated with our equity gas, we recognize revenue for the fees charged to third-parties for such services.

Gas Marketing

When we market and sell gas for working interest owners, we act as agent under short-term sales and supply agreements and may earn a fee for such services. Revenues from such services are recognized as gas is delivered.

Gas Imbalances

Revenue from the sale of gas is recorded on the basis of gas actually sold by us. If our aggregate sales volumes for a well are greater (or less) than our proportionate share of production from the well, a liability (or receivable) is established to the extent there are insufficient proved reserves available to make-up the overproduced (or underproduced) imbalance. Imbalances have not been significant in the periods presented.

General and Administrative Expenses

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

Derivatives

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

Income Taxes

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in the financial statements and tax returns. We classify all deferred tax assets and liabilities as non-current. We routinely assess the realizability of our deferred tax assets. We routinely assess the realizability of our deferred tax assets. Numerous judgments and assumptions are inherent in this assessment, including the determination of future taxable income, which is affected by factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws. If we conclude that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. We regularly assess and, if required, establish accruals for tax contingencies that could result from assessments of additional tax by taxing jurisdictions where the company operates. See Note 9 for additional information regarding our income taxes.

Contingencies

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

Asset Retirement Obligations

We recognize the present value of 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. In periods subsequent to the initial measurement of an asset retirement obligation at present value, a period-to-period increase in the carrying amount of the liability is recognized as accretion expense, which represents the effect of the passage of time on the amount of the liability. An equivalent amount is added to the carrying amount of the liability. 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 portion of our asset retirement obligations is recorded in "Accrued liabilities — Other" in the accompanying consolidated balance sheets and cash payments for settlements of retirement obligations are classified as cash used in operating activities in the accompanying consolidated statements of cash flows. See Note 8 for additional information regarding our asset retirement obligations.

Stock-based Compensation

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

Earnings (Loss) per Share

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

Recently Issued Accounting Standards

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). The key provision of Topic 842 is that a lessee must recognize (i) liabilities to make lease payments and (ii) right-of-use assets on its balance sheet. The ASU permits lessees to make a policy election to not recognize lease assets and liabilities for leases with terms of less than twelve months. Under current GAAP, a determination of whether a lease is a capital or operating lease is made at lease inception and no assets or liabilities are recognized for operating leases. Under Topic 842, the determination to be made at the inception of a contract is whether the contract is, or contains, a lease. Leases convey the right to control the use of an identified asset in exchange for consideration. Only the lease components of a contract must be accounted for in accordance with Topic 842. Non-lease components, such as activities that transfer a good or service to the customer, shall be accounted for under other applicable Topics. An entity may make a policy election to not separate lease and non-lease components and account for the non-lease components together with the lease components as a single lease component. Topic 842 retains a distinction between finance and operating leases concerning the recognition and presentation of the expense and payments related to leases in the statements of operations and comprehensive income and cash flows, however, both types of leases require the recognition of assets and liabilities on the balance sheet. Topic 842 is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, with early adoption permitted. We will adopt Topic 842 effective January 1, 2019, recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The primary effect of adoption will be to record assets and liabilities for contracts currently accounted for as operating leases, such as leases for office space, compressors, and other equipment.

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In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842. This ASU provides an optional transition practical expedient to not evaluate under Topic 842 (discussed above) existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. Under the full cost method of accounting, we capitalize to oil and gas properties all property acquisition, exploration, and development costs, which include the costs of land easements. We plan to elect this practical expedient and continue to apply our current accounting policy to account for land easements that existed before our adoption of Topic 842 and will evaluate new or modified land easements under Topic 842 upon our adoption of Topic 842.

2. CAPITAL STOCK

Authorized capital stock consists of 200 million shares of common stock and 15 million shares of preferred stock. At December 31, 2018, there were 95.8 million shares of common stock and 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. A dividend of $0.18 per share was declared in both the third and fourth quarters of 2018 while a dividend of $0.16 per share was declared in the first and second quarters of 2018. In each quarter of 2017 and 2016 an $0.08 per share dividend was declared. We typically declare dividends in one quarter and pay them in the next quarter. At December 31, 2018, we had dividends payable of $17.3 million that was included in "Accrued liabilities — other". Dividends declared are recorded as a reduction of retained earnings to the extent retained earnings are available at the close of the period prior to the date of the declared dividend. Dividends in excess of retained earnings are recorded as a reduction of additional paid-in capital. During 2018, the dividend declared during the first quarter was recorded as a reduction of additional paid-in capital, while the remaining three dividends declared were recorded as a reduction of retained earnings. All dividends declared during 2017 and 2016 were recorded as a reduction of additional paid-in capital. Nonforfeitable dividends paid on stock awards that subsequently forfeit are reclassified out of retained earnings or additional paid-in capital, as applicable, to compensation expense in the period in which the forfeitures occur. Future dividend payments will depend on our level of earnings, financial requirements, and other factors considered relevant by our Board of Directors.

3. LONG-TERM DEBT

Long-term debt at December 31, 2018 and 2017 consisted of the following:

	December 31, 2018			December 31, 2017		
(in thousands)	Principal	Unamortized Debt Issuance Costs and Discount (1)	Long-term Debt, net	Principal	Unamortized Debt Issuance Costs and Discount (1)	Long-term Debt, net
4.375% Senior Notes	$750,000	$ (4,439)	$745,561	$750,000	$ (5,383)	$744,617
3.90% Senior Notes	750,000	(7,007)	742,993	750,000	(7,697)	742,303
Total long-term debt	$1,500,000	$ (11,446)	$1,488,554	$1,500,000	$ (13,080)	$1,486,920

(1) At December 31, 2018, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.4 million and $1.6 million, respectively. At December 31, 2017, the unamortized debt issuance costs and discount related to the 3.90% notes were $5.9 million and $1.8 million, respectively. The 4.375% notes were issued at par.

Bank Debt

In October 2015, we entered into a Credit Agreement for a senior unsecured revolving credit facility ("Credit Facility") with an aggregate commitment of $1.0 billion, which matures October 16, 2020. There is no borrowing base subject to the discretion of the lenders based on the value of our proved reserves under the Credit Facility. As of

December 31, 2018, we had no bank borrowings outstanding under the Credit Facility, but did have letters of credit of $2.5 million outstanding, leaving an unused borrowing availability of $997.5 million.

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

The Credit Facility contains representations, warranties, covenants, and events of default that are customary for investment grade, senior unsecured bank credit agreements, including a financial covenant for the maintenance of a defined total debt-to-capital ratio of no greater than 65%. As of December 31, 2018, we were in compliance with all of the financial covenants.

At December 31, 2018 and 2017, we had $2.2 million and $3.4 million, respectively, of unamortized debt issuance costs associated with our Credit Facility which were recorded as deferred assets and included in “Other assets” in our balance sheets. The costs are being amortized to interest expense ratably over the life of the Credit Facility.

Subsequent Event

On February 5, 2019, we entered into an Amended and Restated Credit Agreement. Among other things, the amended and restated credit facility increases the aggregate commitment to $1.25 billion with an option to increase the commitment to $1.5 billion, and extends the maturity date to February 5, 2024.

Senior Notes

On April 10, 2017, we completed a cash tender offer to purchase any of our 5.875% notes for cash consideration of $1,031.67 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the settlement date, with $253.5 million aggregate principal amount of the notes validly tendered. We settled these tendered notes for $268.1 million, including accrued interest. On May 12, 2017, we completed a redemption of the 5.875% notes remaining outstanding for $1,029.38 per $1,000 principal amount of notes, plus any accrued and unpaid interest up to, but not including, the redemption date, settling the notes for $512.0 million, including accrued interest. We recognized a loss on early extinguishment of debt related to these transactions of $28.2 million, composed primarily of tender and redemption premiums of $22.6 million and the write-off of $5.3 million of unamortized debt issuance costs. The original maturity date of the 5.875% notes was May 1, 2022.

On April 10, 2017, we issued $750 million aggregate principal amount of 3.90% senior unsecured notes due May 15, 2027 at 99.748% of par to yield 3.93% per annum. We received $741.8 million in net cash proceeds, after deducting underwriters’ fees, discount, and debt issuance costs. The notes bear an annual interest rate of 3.90% and interest is payable semiannually on May 15 and November 15, with the first payment occurring November 15, 2017. Along with cash on hand, we used the proceeds to fund the settlement of the tendered and redeemed 5.875% notes.

In June 2014, we issued $750 million aggregate principal amount of 4.375% senior unsecured notes at par. These notes are due June 1, 2024 and interest is payable semiannually on June 1 and December 1.

Each of our senior unsecured notes is governed by an indenture containing certain covenants, events of default, and other restrictive provisions with which we were in compliance as of December 31, 2018. The effective interest rate on the 4.375% notes and the 3.90% notes, including the amortization of debt issuance costs and discount, as applicable, is 4.50% and 4.01%, respectively. At December 31, 2018, we had accrued interest related to our notes of $6.4 million that was included in “Accrued liabilities — other”.

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4. DERIVATIVE INSTRUMENTS

We periodically use derivative instruments to mitigate volatility in commodity prices. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future cash flow from favorable price changes. Depending on changes in oil and gas futures markets and management's view of underlying supply and demand trends, we may increase or decrease our derivative positions from current levels.

As of December 31, 2018, we have entered into oil and gas collars and oil basis swaps. Under our collars, we receive the difference between the published index price and a floor price if the index price is below the floor price or we pay the difference between the ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and the ceiling prices. By using a collar, we have fixed the minimum and maximum prices we can receive on the underlying production. Our basis swaps are settled based on the difference between a published index price minus a fixed differential and the applicable local index price under which the underlying production is sold. By using a basis swap, we have fixed the differential between the published index price and certain of our physical pricing points. For our Permian oil production, the basis swaps fix the price differential between the WTI NYMEX (Cushing Oklahoma) price and the WTI Midland price. For our Permian and Mid-Continent gas production, the contract prices in our collars are consistent with the index prices used to sell our production. The following tables summarize our outstanding derivative contracts as of December 31, 2018:

Oil Collars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2019:					
WTI (1)					
Volume (Bbls)	2,790,000	2,821,000	2,208,000	1,472,000	9,291,000
Weighted Avg Price - Floor	$ 53.94	$ 53.94	$ 55.67	$ 58.50	$ 55.07
Weighted Avg Price - Ceiling	$ 66.88	$ 66.88	$ 70.03	$ 71.94	$ 68.43
2020:					
WTI (1)					
Volume (Bbls)	728,000	—	—	—	728,000
Weighted Avg Price - Floor	$ 60.00	$ —	$ —	$ —	$ 60.00
Weighted Avg Price - Ceiling	$ 75.85	$ —	$ —	$ —	$ 75.85

(1) The index price for these collars is West Texas Intermediate ("WTI") as quoted on the New York Mercantile Exchange ("NYMEX").

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Gas Collars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2019:					
PEPL (1)					
Volume (MMBtu)	10,800,000	10,920,000	8,280,000	5,520,000	35,520,000
Weighted Avg Price - Floor	$ 2.05	$ 2.05	$ 1.93	$ 1.93	$ 2.00
Weighted Avg Price - Ceiling	$ 2.42	$ 2.42	$ 2.34	$ 2.42	$ 2.40
Perm EP (2)					
Volume (MMBtu)	7,200,000	7,280,000	5,520,000	2,760,000	22,760,000
Weighted Avg Price - Floor	$ 1.69	$ 1.69	$ 1.48	$ 1.37	$ 1.60
Weighted Avg Price - Ceiling	$ 1.92	$ 1.92	$ 1.74	$ 1.60	$ 1.84
Waha (3)					
Volume (MMBtu)	2,700,000	2,730,000	2,760,000	2,760,000	10,950,000
Weighted Avg Price - Floor	$ 1.38	$ 1.38	$ 1.38	$ 1.38	$ 1.38
Weighted Avg Price - Ceiling	$ 1.67	$ 1.67	$ 1.67	$ 1.67	$ 1.67
2020:					
PEPL (1)					
Volume (MMBtu)	2,730,000	—	—	—	2,730,000
Weighted Avg Price - Floor	$ 1.97	$ —	$ —	$ —	$ 1.97
Weighted Avg Price - Ceiling	$ 2.51	$ —	$ —	$ —	$ 2.51
Perm EP (2)					
Volume (MMBtu)	910,000	—	—	—	910,000
Weighted Avg Price - Floor	$ 1.40	$ —	$ —	$ —	$ 1.40
Weighted Avg Price - Ceiling	$ 1.70	$ —	$ —	$ —	$ 1.70
Waha (3)					
Volume (MMBtu)	1,820,000	—	—	—	1,820,000
Weighted Avg Price - Floor	$ 1.40	$ —	$ —	$ —	$ 1.40
Weighted Avg Price - Ceiling	$ 1.73	$ —	$ —	$ —	$ 1.73

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(1) The index price for these collars is Panhandle Eastern Pipe Line, Tex/OK Mid-Continent Index ("PEPL") as quoted in Platt's Inside FERC.

(2) The index price for these collars is El Paso Natural Gas Company, Permian Basin Index ("Perm EP") as quoted in Platt's Inside FERC.

(3) The index price for these collars is Waha West Texas Natural Gas Index ("Waha") as quoted in Platt's Inside FERC.

Oil Basis Swaps	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2019:					
WTI Midland (1)					
Volume (Bbls)	2,610,000	2,639,000	2,208,000	1,472,000	8,929,000
Weighted Avg Differential (2)	$ (5.46)	$ (5.46)	$ (6.50)	$ (7.79)	$ (6.10)
2020:					
WTI Midland (1)					
Volume (Bbls)	637,000	637,000	—	—	1,274,000
Weighted Avg Differential (2)	$ (0.40)	$ (0.40)	$ —	$ —	$ (0.40)

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(1) The index price we pay under these basis swaps is WTI Midland as quoted by Argus Americas Crude.
(2) The index price we receive under these basis swaps is WTI as quoted on the NYMEX less the weighted average differential shown in the table.

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The following tables summarize our derivative contracts entered into subsequent to December 31, 2018 through February 15, 2019:

Oil Collars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2019:					
WTI (1)					
Volume (Bbls)	62,000	182,000	184,000	184,000	612,000
Weighted Avg Price - Floor	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$ 50.00
Weighted Avg Price - Ceiling	$ 62.60	$ 62.60	$ 62.60	$ 62.60	$ 62.60
2020:					
WTI (1)					
Volume (Bbls)	182,000	182,000	—	—	364,000
Weighted Avg Price - Floor	$ 50.00	$ 50.00	$ —	$ —	$ 50.00
Weighted Avg Price - Ceiling	$ 62.60	$ 62.60	$ —	$ —	$ 62.60

(1) The index price for these collars is WTI as quoted on the NYMEX.

Gas Collars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2019:					
PEPL (1)					
Volume (MMBtu)	1,770,000	2,730,000	2,760,000	2,760,000	10,020,000
Weighted Avg Price - Floor	$ 1.95	$ 1.95	$ 1.95	$ 1.95	$ 1.95
Weighted Avg Price - Ceiling	$ 2.26	$ 2.26	$ 2.26	$ 2.26	$ 2.26
Perm EP (2)					
Volume (MMBtu)	590,000	910,000	920,000	920,000	3,340,000
Weighted Avg Price - Floor	$ 1.50	$ 1.50	$ 1.50	$ 1.50	$