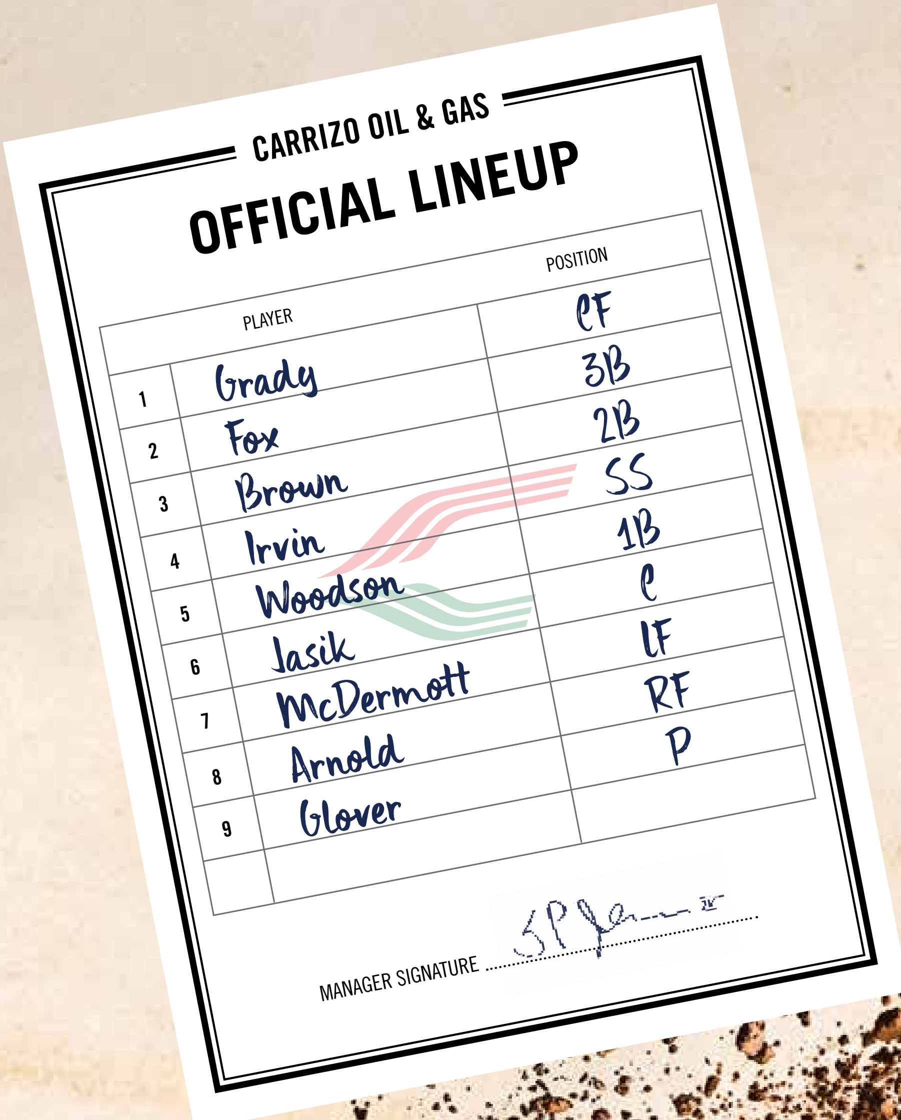
A WINNING LINEUP



2017 ANNUAL REPORT

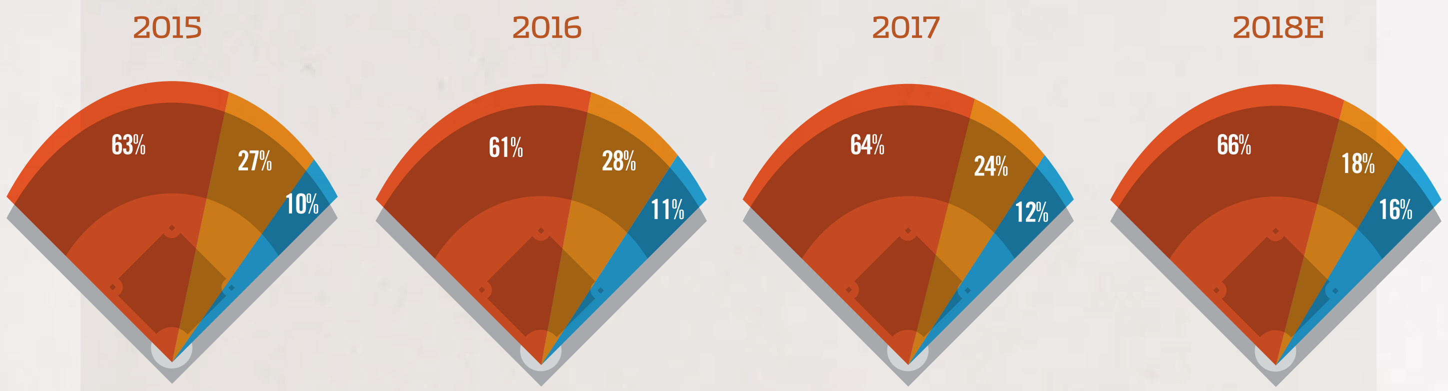
CARRIZO

CARRIZO OIL & GAS, INC. is a Houston-based energy company actively engaged in the exploration, development, and production of oil and gas from resource plays located in the United States. Our current operations are principally focused in proven, producing hydrocarbon basins primarily in the Eagle Ford Shale in South Texas and the Delaware Basin in West Texas.

We have successfully grown our production and reserves by being an industry leader in horizontal drilling and completion techniques in unconventional resource plays. To date, we have drilled and completed more than 1,000 horizontal wells across multiple resource plays. And much the way baseball teams use data analytics to determine where to position their players in the field, we use the data accumulated from our past activity to help determine how and where to place future wellbores in order to maximize our results. This disciplined approach has helped us continue to drill wells that rank among the best in our core areas.

Crude oil plays continue to be the driver of our future production and revenue growth. As of February 27, 2018, we had accumulated more than 80,000 net acres in the Eagle Ford Shale and approximately 42,000 net acres in the Delaware Basin. We currently have a drilling inventory of more than 1,700 net potential locations across our acreage position. This provides us with a solid foundation from which to generate long-term growth in our reserves and production.

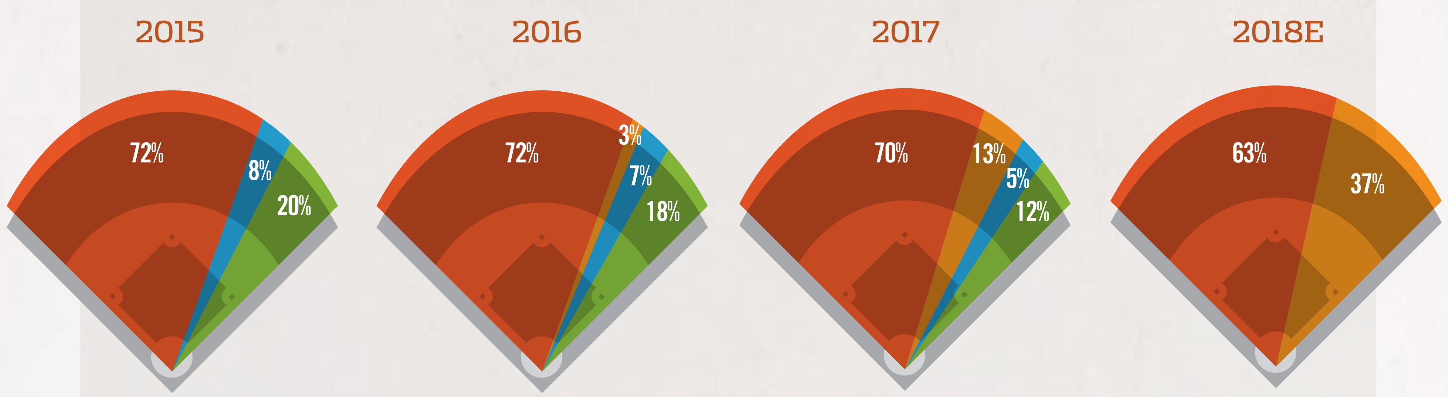
FINANCIAL HIGHLIGHTS



PRODUCTION

Production is expected to grow by approximately 10% in 2018; pro forma for A&D activity, it should be up more than 30%.

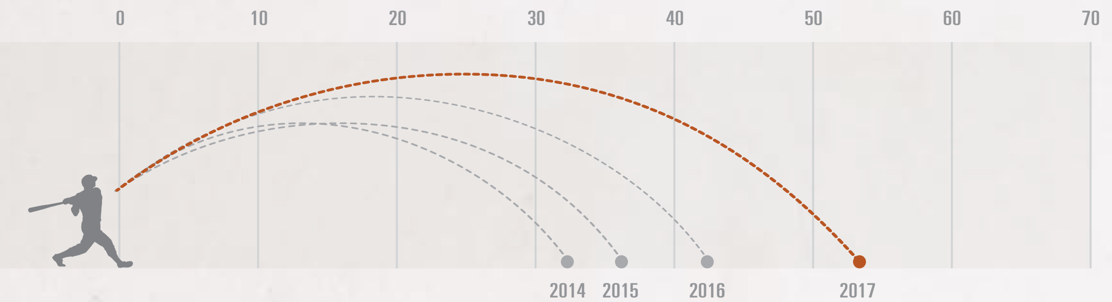
CRUDE OIL NATURAL GAS NATURAL GAS LIQUIDS



PRODUCTION BY BASIN

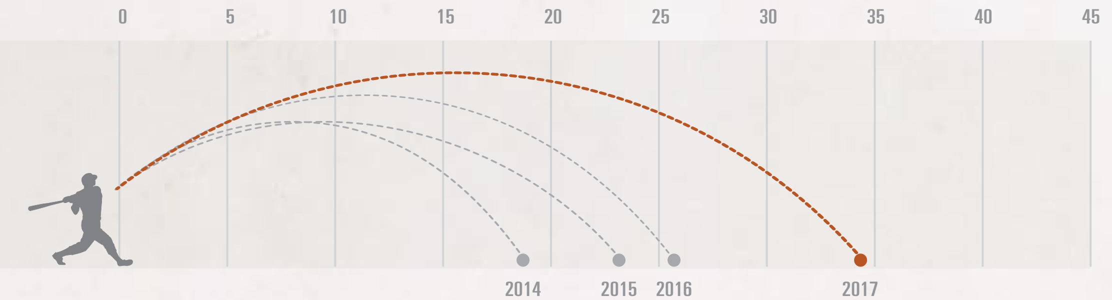
As the Delaware Basin is expected to grow at a faster rate than the Eagle Ford Shale, it should account for a greater percentage of total production in 2018.

EAGLE FORD DELAWARE BASIN DJ BASIN APPALACHIA



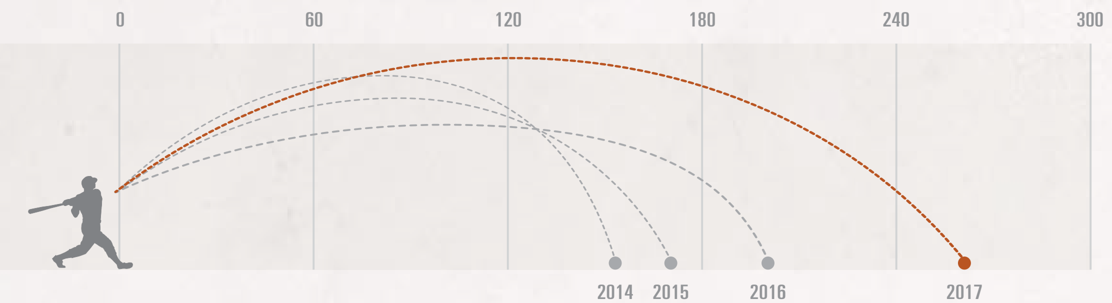
TOTAL PRODUCTION (MBoe/d)

2017 total production increased to 53.8 MBoe/d, an increase of 27% versus 2016 thanks to acquisitions in the Eagle Ford Shale and Delaware Basin, as well as strong growth from each play.



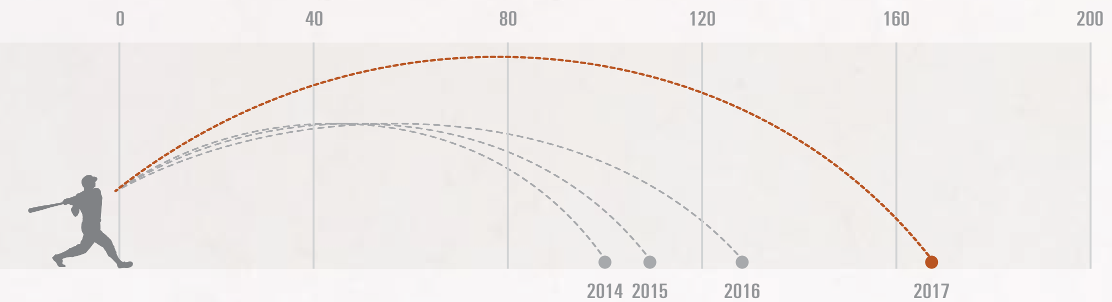
CRUDE OIL PRODUCTION (MBbls/d)

2017 crude oil production increased to 34.4 MBbls/d, up 34% versus 2016, a faster growth rate than seen in total production given the focus on oily plays.



TOTAL PROVED RESERVES (MMBoe)

2017 total reserve replacement was 564% at an all-sources FD&A cost of $13.47/Boe.



PROVED OIL RESERVES (MMBbls)

Delaware Basin bookings drove a more than 30% increase in proved oil reserves during 2017.

LETTER TO SHAREHOLDERS

2017 ANNUAL REPORT

To be successful in baseball, the GM and other management must make a number of strategic decisions to put a winning team on the field. Not only do they have to assemble a roster of talented players, they also have to find a team with the right chemistry. And while the nucleus of a team typically comes from a strong farm system, organizations have to supplement this by making trades or acquiring players through free agency in order to have a championship-caliber team.

There are many parallels between this process and what we have striven to do at Carrizo. As we entered 2017, we had a position in five different oil and gas plays across the U.S., each of which we had built primarily through organic leasing efforts. And while we could have generated future growth by continuing our operations in all of them, we felt a better strategy for maximizing value for our shareholders would be to focus on one or two, making sure we had enough scale in each to be able to run an efficient development program that generated strong returns. We also identified balance sheet improvement as an area that could help maximize shareholder value. In the past, we believed carrying a higher amount of financial leverage was an acceptable level of risk for an E&P company, as this resulted in a lower cost of capital. However, with the increased volatility in commodity prices, we now think it is prudent to run the business with a lower amount of financial leverage, and have targeted bringing this down below 2x over time.

We elected to build the new Carrizo by focusing our efforts on the Eagle Ford Shale and Delaware Basin, as these two plays consistently rank among the top three most economical plays in the U.S. Additionally, as both plays are in Texas, the risk of excessively onerous regulations is lower than in the other regions where we operated. As we had an excellent position in the volatile oil window of the Eagle Ford Shale, our focus was on building additional scale in the Delaware Basin. We were able to achieve this last August when we closed on the acquisition of more than 16,500 net acres in the core of the Delaware Basin, bringing our position in the play to more than 42,000 net acres.

Once we had achieved a core position in our two focus basins, we shifted our focus to streamlining the portfolio and reducing our leverage. During the last four months of 2017, we announced the sale of our assets in other plays, as well as the sale of our downdip assets in the Eagle Ford Shale. In total, the announced proceeds from these sales were more than $530 million, and we used this to help retire $470 million of long-term debt and $50 million of preferred securities. This has helped us reduce our leverage by more than a turn since mid-2017.

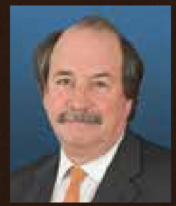
"The idea that you can create a template that will work forever doesn't happen in any business."

– Billy Beane

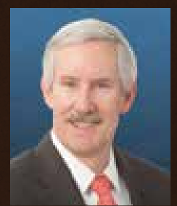
As a result of these strategic moves, we currently have a focused portfolio that provides us with a deep inventory of high-return drilling locations. We currently have more than 1,100 net derisked locations in our inventory, with another 600-plus potential net locations in the Delaware Basin depending on how many additional layers are economical. This should allow us to generate profitable growth for many years.

For 2018, our planned capital program is $750-$800 million, up from $652 million in 2017 as we have more activity planned in the Delaware Basin. Our program is relatively balanced between the two plays, with approximately 55% of the capital earmarked for the Eagle Ford Shale and the balance for the Delaware Basin. Based on this level of spending, we expect to grow our production by approximately 10% during the year, or more than 30% pro forma for our acquisition and divestiture activity.

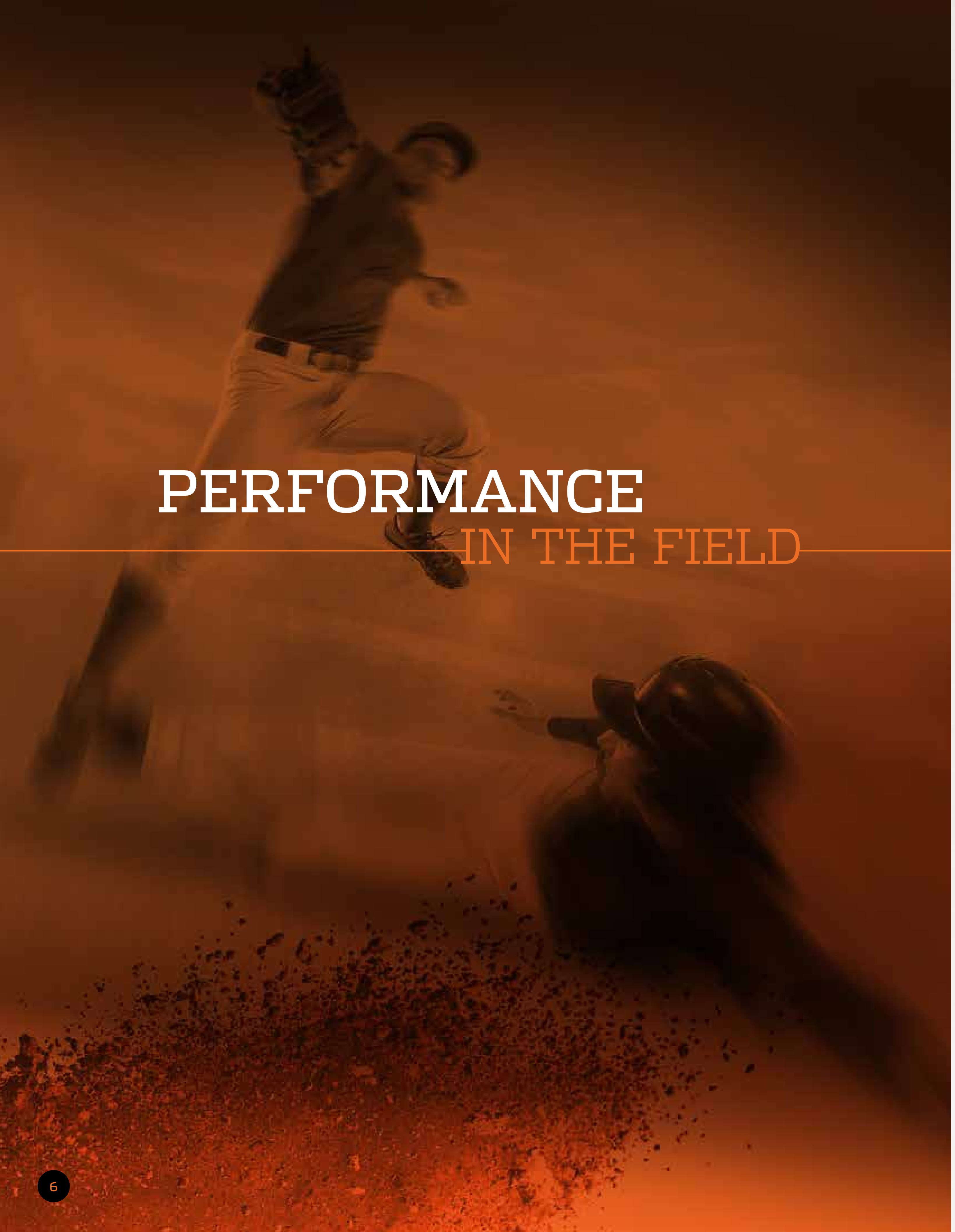
In closing, we would like to recognize our employees and contractors, whose hard work and dedication, as well as willingness to be shifted around following our transformational year, have us well positioned for future success.



Steve A. Webster
Chairman



S.P. Johnson, IV
President and CEO



PERFORMANCE IN THE FIELD

TURNING TWO

Following our strategic shift during 2017, we have a portfolio focused on two plays, the Eagle Ford Shale and Delaware Basin, where we currently hold more than 122,000 net acres. And much the way infielders work together to turn a double play, we believe that these assets work together to give us a high chance of success while managing our risk. We have a deep inventory of high-return drilling locations in each play, with more than 700 net derisked locations in the Eagle Ford Shale and more than 400 in the Delaware Basin. While the drilling locations are in two plays, their proximity makes it relatively easy for us to shift activity between them. This allows us to take advantage of market opportunities or manage any potential short-term basin-wide bottlenecks by shifting capital to the basin generating the highest returns.

We have been active in the Eagle Ford Shale since 2010, and have drilled more than 400 wells in the play since that time. This has provided us with a substantial amount of data, which we have used to continually optimize our activities. This continued focus on improvement has led to us being one of the most efficient operators in the basin. We currently have two rigs running in the play, and typically drill wells in about 10 days, down about 50% from when we first started operating in the play despite laterals that are 60% longer. Our completions operations also rank us among the most efficient operators in the play. Our dedicated completion crew typically averages about 7 frac stages per day, and consistently ranks as one of the top crews in the pressure pumper's fleet.

As we ramp up our activity in the Delaware Basin during 2018, we expect to leverage the knowledge we have acquired operating in other plays such as the Eagle Ford Shale. Our operations in the Delaware Basin are still relatively new, so we see significant opportunities to improve our efficiencies over time; this should hopefully result in lower costs and enhanced returns. For example, we are currently drilling wells in the Delaware Basin in 30-45 days and completing 3-4 stages per day. As we move to pad drilling and bring other learnings into the basin, we expect to materially improve upon both of these metrics.

Year	Area	Net Acreage	Wells Drilled	Reserves (MMBoe) Oil	Gas	NGLs	Total	Production (MBoe/d) Oil	Gas	NGLs	Total	% Liq.
2010	S. Texas	20.4	5	7.2	4.3	3.5	15.0	0.1	0.0	0.0	0.1	1.000
2011	S. Texas	41.0	30	21.4	4.1	3.0	28.5	1.4	0.2	0.1	1.8	0.883
2012	S. Texas	49.0	59	36.5	7.2	5.2	49.0	6.5	0.8	0.6	7.9	0.895
2013	S. Texas	62.2	59	57.6	8.5	7.8	73.9	10.0	1.3	1.4	12.6	0.896
2014	S. Texas	81.0	69	96.1	13.6	12.8	122.5	16.6	2.3	2.3	21.1	0.891
2015	S. Texas	82.7	71	105.8	19.2	19.0	144.0	20.2	3.1	3.1	26.4	0.883
2016	S. Texas	100.2	77	120.9	20.9	20.5	162.3	22.7	3.9	4.1	30.7	0.872
2017	S. Texas	103.1	91	124.2	21.1	21.7	167.0	29.5	4.0	4.3	37.8	0.894

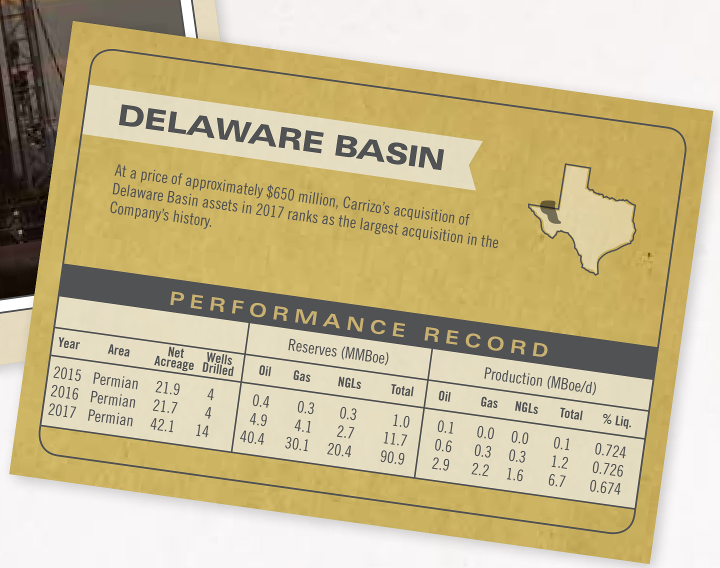
Mickey Vernon was part of more than 2,000 double plays over his 20-year career, the most in baseball history.

EXPANDING THE ZONE

One of the things that attracted us to the Delaware Basin was the stacked pay nature of the play. Most oil and gas plays have only one or two zones that could be prospective. But in the Delaware Basin, we see up to 10 potential targets across a 3,800-ft.-thick geologic section stretching from the Avalon Shale down to the Wolfcamp D.

To date, our development activity has focused on the Wolfcamp A as well as the Upper and Lower Wolfcamp B, where we currently have more than 400 net derisked locations in our inventory. This equates to a more than 10-year inventory of drilling locations at our current pace. Over time, our focus is to not only exploit these high-return locations, but also expand the derisked pay zone to include other targets. Assuming this is successful, we have the potential to more than double our inventory of derisked locations on the acreage.

The industry has already begun testing some of these other targets. We currently have a well producing out of the Wolfcamp D on our acreage, and offset production has been established in the Wolfcamp C, Wolfcamp X/Y, and 3rd Bone Spring. While we don't expect all seven additional targets to be economical across the entirety of our acreage position in the Delaware Basin, the sheer size of the target zone means that the probability of at least one or two additional targets working are in our favor. During 2018, our activity is expected to remain focused on development of the Wolfcamp A and B, though we do plan to drill at least one test of another target later in the year.


DELAWARE BASIN

At a price of approximately $650 million, Carrizo's acquisition of Delaware Basin assets in 2017 ranks as the largest acquisition in the Company's history.

PERFORMANCE RECORD

				Reserves (MMBoe)				Production (MBoe/d)				
Year	Area	Net Acreage	Wells Drilled	Oil	Gas	NGLs	Total	Oil	Gas	NGLs	Total	% Liq.
2015	Permian	21.9	4	0.4	0.3	0.3	1.0	0.1	0.0	0.0	0.1	0.724
2016	Permian	21.7	4	4.9	4.1	2.7	11.7	0.6	0.3	0.3	1.2	0.726
2017	Permian	42.1	14	40.4	30.1	20.4	90.9	2.9	2.2	1.6	6.7	0.674

Between 2008 and 2016, the downward expansion of the strike zone resulted in more success for pitchers, as strikeout rates increased by more than 20% over the period. (Stark, 2016)

THE COUNT'S IN OUR FAVOR

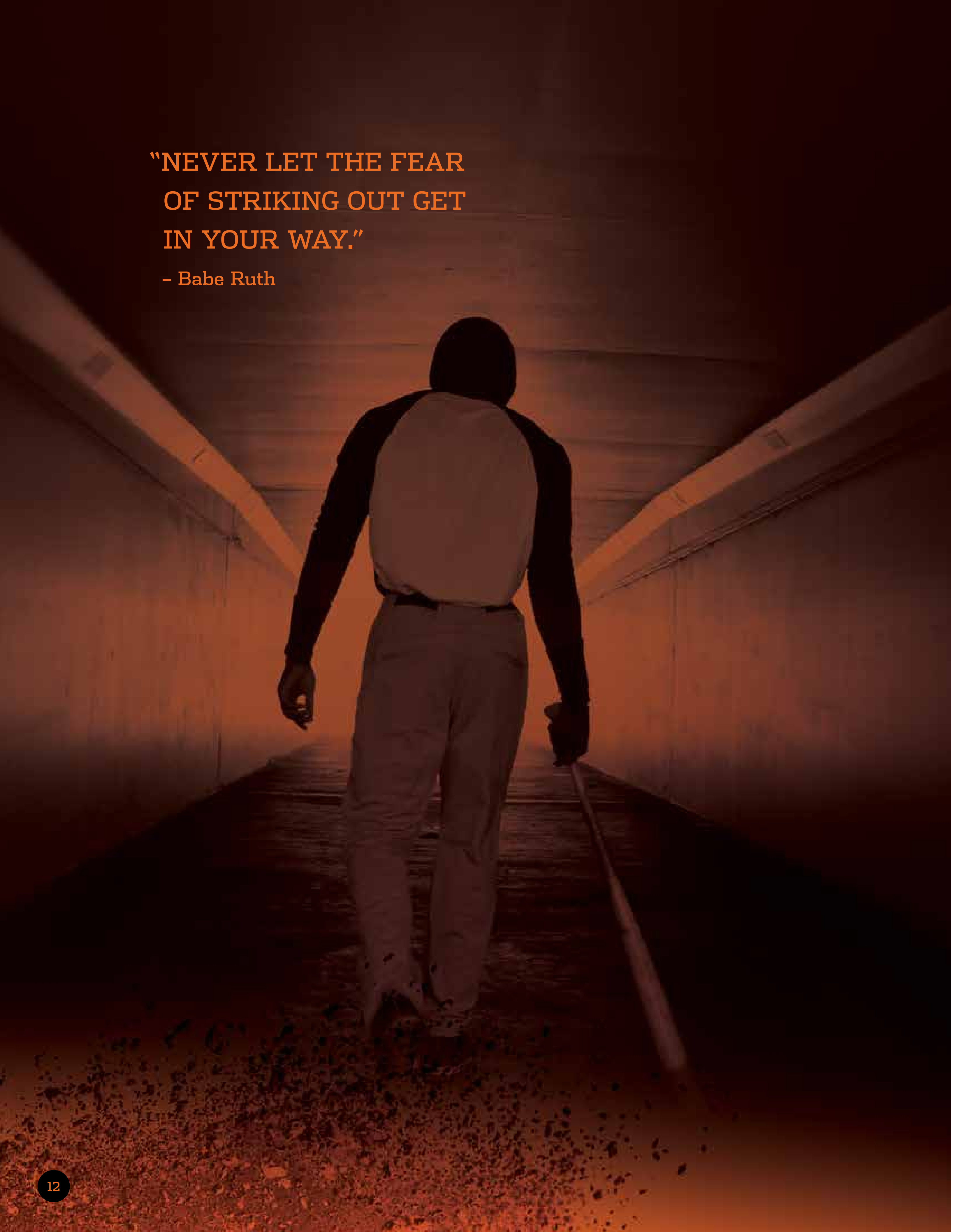
READY FOR A CHAMPIONSHIP DRIVE

While assembling the right portfolio of assets was a key component of our strategic shift, it was not the only part of our plan. We also wanted to ensure that we had an appropriate financial strategy and balance sheet in order to be able to economically develop our assets in any commodity price environment.

Following the ExL acquisition in the Delaware Basin, we elected to further strengthen our balance sheet by monetizing non-core assets and using the proceeds to reduce debt. Our Appalachian asset sales closed in the fourth quarter of 2017, while our DJ Basin and downdip Eagle Ford asset sales closed this January. The proceeds from these deals allowed us to redeem $470 million of our long-term debt as well as $50 million of preferred stock. As a result, our leverage has declined by more than a turn since mid-2017, and our goal is to further reduce it below 2x. We believe this will give us sufficient financial flexibility to manage future volatility in commodity prices.

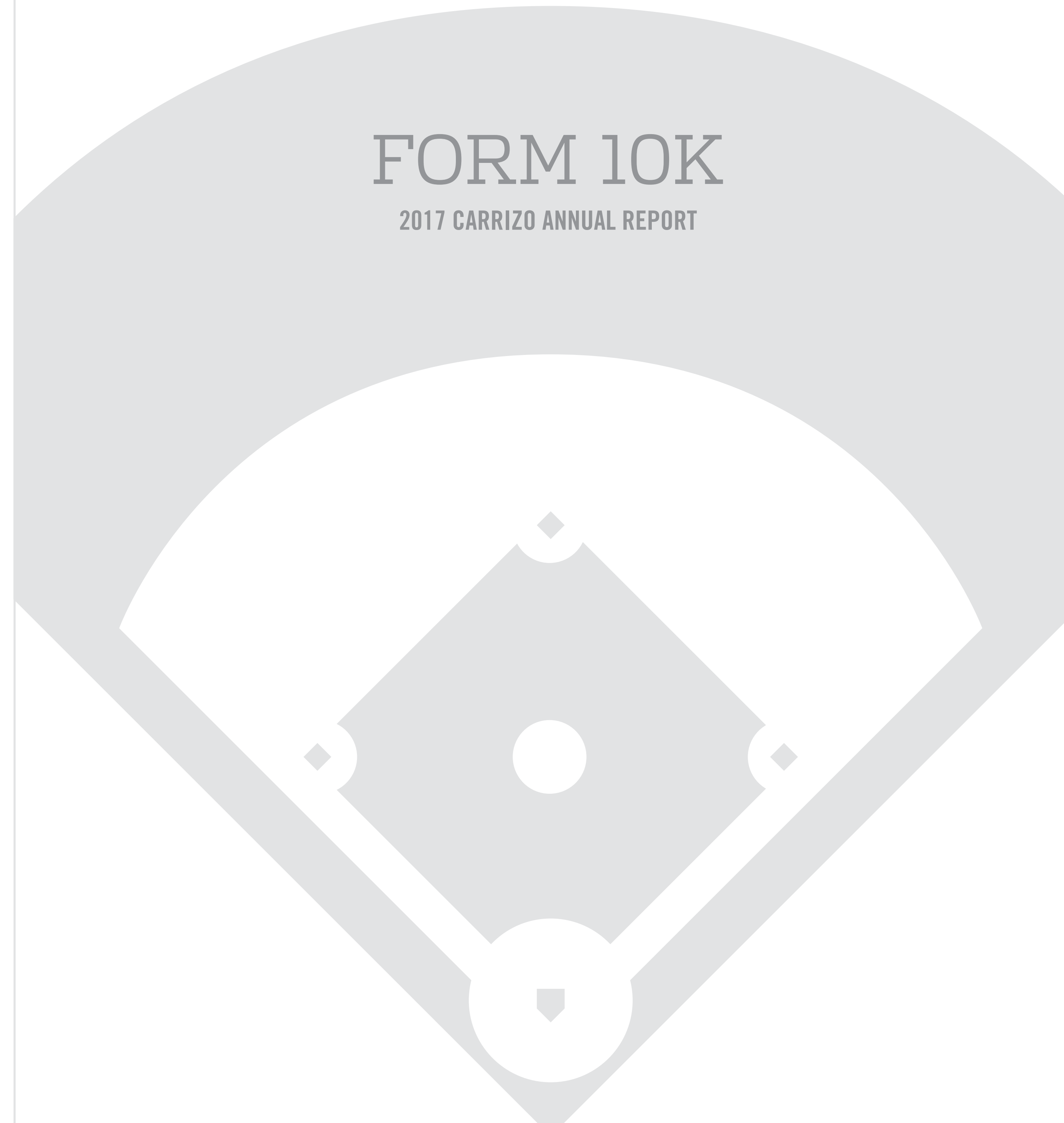
We seek to protect our cash flows and returns through our hedging activity. For 2018, we currently have hedges covering approximately 75% of estimated crude oil production. We have also placed hedges on more than 50% of our estimated NGL production and approximately 35% of our estimated natural gas production. Based on current oilfield service cost assumptions, these hedges lock in a strong minimum operating margin on a large percentage of our production.

As a result of these moves, we are in a strong position to execute on our corporate goals of generating prudent, economical growth, and being able to consistently deliver this within our cash flow.



FORM 10K

2017 CARRIZO ANNUAL REPORT



CARRIZO

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the Fiscal Year Ended December 31, 2017

Commission File Number 000-29187-87

Carrizo Oil & Gas, Inc.

(Exact name of registrant as specified in its charter)

Texas	**76-0415919**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
500 Dallas Street, Suite 2300 Houston, Texas	**77002**
(Principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (713) 328-1000

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

Common Stock, $0.01 par value	**NASDAQ Global Select Market**
(Title of class)	(Name of exchange on which registered)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

YES ☑ NO ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

YES ☐ NO ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ☑ NO ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ☑ NO ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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. (Check one):

Large accelerated filer ☑		Accelerated filer	☐
Non-accelerated filer ☐	(Do not check if a smaller reporting company)	Smaller reporting company	☐
		Emerging growth company	☐

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. ☐

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

At June 30, 2017, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $1.1 billion based on the closing price of such stock on such date of $17.42.

At February 23, 2018, the number of shares outstanding of the registrant's Common Stock was 81,469,593.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2018 Annual Meeting of Shareholders are incorporated by reference in Part III of this Form 10-K. Such definitive proxy statement will be filed with the U.S. Securities and Exchange Commission not later than 120 days subsequent to December 31, 2017.

TABLE OF CONTENTS

Forward-Looking Statements

This annual report contains statements concerning our intentions, expectations, projections, assessments of risks, estimations, beliefs, plans or predictions for the future, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements include, among others, statements regarding:

- our growth strategies;
- our ability to explore for and develop oil and gas resources successfully and economically;
- our estimates and forecasts of the timing, number, profitability and other results of wells we expect to drill and other exploration activities;
- our estimates regarding timing and levels of production;
- changes in working capital requirements, reserves, and acreage;
- commodity price risk management activities and the impact on our average realized prices;
- anticipated trends in our business;
- availability of pipeline connections and water disposal on economic terms;
- effects of competition on us;
- our future results of operations;
- profitability of drilling locations;
- our liquidity and our ability to finance our exploration and development activities, including accessibility of borrowings under our revolving credit facility, our borrowing base, modification to financial covenants and the result of any borrowing base redetermination;
- our planned expenditures, prospects and capital expenditure plan;
- future market conditions in the oil and gas industry;
- our ability to make, integrate and develop acquisitions and realize any expected benefits or effects of completed acquisitions;
- the benefits, effects, availability of and results of new and existing joint ventures and sales transactions;
- our ability to maintain a sound financial position;
- receipt of receivables, drilling carry and proceeds from sales;
- our ability to complete planned transactions on desirable terms; and
- the impact of governmental regulation, taxes, market changes and world events.

You generally can identify our forward-looking statements by the words "anticipate," "believe," budgeted," "continue," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "objective," "plan," "potential," "predict," "projection," "scheduled," "should," or other similar words. Such statements rely on assumptions and involve risks and uncertainties, many of which are beyond our control, including, but not limited to, those relating to a worldwide economic downturn, availability of financing, our dependence on our exploratory drilling activities, the volatility of and changes in oil and gas prices, the need to replace reserves depleted by production, impairments of proved oil and gas properties, operating risks of oil and gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, interpretations and impact of oil and gas reserve estimation and disclosure requirements, activities and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, the timing and amount of borrowing base determinations (including determinations by lenders) and availability under our revolving credit facility, evaluations of us by lenders under our revolving credit facility, other actions by lenders, the potential impact of government regulations, including current and proposed legislation and regulations related to hydraulic fracturing, oil and natural gas drilling, air emissions and climate change, regulatory determinations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, acquisition risks, availability of equipment and crews, actions by midstream and other industry participants, weather, our ability to obtain permits and licenses, the results of audits and assessments, the failure to obtain certain bank and lease consents, the existence and resolution of title defects, new taxes and impact fees, delays, costs and difficulties relating to our joint ventures, actions by joint venture parties, results of exploration activities, the availability, market conditions and completion of land acquisitions and dispositions, costs of oilfield services, completion and connection of wells, and other factors detailed in this annual report.

We have based our forward-looking statements on our management's beliefs and assumptions based on information available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the factors that could cause actual results to differ from those expressed or implied in forward-looking statements are described under Part I, "Item 1A. Risk Factors" and in other sections of this annual report. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on our forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and, except as required by law, we undertake no duty to update or revise any forward-looking statement.

Certain terms used herein relating to the oil and gas industry are defined in "Glossary of Certain Industry Terms" included under Part I, "Item 1. Business."

PART I

Item 1. Business

General Overview

Carrizo Oil & Gas, Inc. is a Houston-based energy company which, together with its subsidiaries (collectively, "Carrizo," the "Company" or "we"), is actively engaged in the exploration, development, and production of crude oil, NGLs, and gas from resource plays located in the United States. Our current operations are principally focused in proven, producing oil and gas plays in the Eagle Ford Shale in South Texas and the Delaware Basin in West Texas.

Significant Developments in 2017

Acquisitions. In the third quarter of 2017, we closed on an acquisition of 16,508 net acres located in the Delaware Basin in Reeves and Ward Counties, Texas (the "ExL Properties") from ExL Petroleum Management, LLC and ExL Petroleum Operating Inc. (together "ExL") for aggregate net consideration of $679.8 million (the "ExL Acquisition"). In addition, we have agreed to a contingent payment of $50.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2021 with a cap of $125.0 million.

Divestitures. In the fourth quarter of 2017, we closed on divestitures of substantially all of our assets in the Utica and Marcellus Shales for aggregate net proceeds of approximately $137.0 million, subject to post-closing adjustments. In addition, we could receive combined contingent consideration from the two divestitures of up to $8.0 million per year with a cap of $22.5 million if crude oil and natural gas prices exceed specified thresholds for each of the years of 2018 through 2020.

Also in the fourth quarter of 2017, we entered into purchase and sale agreements to sell substantially all of our assets in the Niobrara Formation and a portion of our assets in the Eagle Ford. Carrizo has received aggregate net proceeds of $382.8 million, subject to post-closing adjustments, for these divestitures, both of which closed in January 2018. In addition, we could receive contingent consideration of $5.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2020 as part of the Niobrara Formation divestiture.

See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" of the Notes to our Consolidated Financial Statements for further details of the transactions discussed above.

Liquidity and financings. In the third quarter of 2017, we completed a number of financing transactions to fund the ExL Acquisition. On July 3, 2017, we completed a public offering of 15.6 million shares of our common stock at a price per share of $14.28 for net proceeds of $222.4 million, net of offering costs. On July 14, 2017, we closed on a public offering of $250.0 million aggregate principal amount of 8.25% Senior Notes due 2025 (the "8.25% Senior Notes") for net proceeds of $245.4 million, net of underwriting discounts and commissions and offering costs. On August 10, 2017, we closed on the issuance and sale of (i) $250.0 million (250,000 shares) of 8.875% redeemable preferred stock, par value $0.01 per share (the "Preferred Stock") and (ii) warrants for 2,750,000 shares of our common stock, with a term of ten years and an exercise price of $16.08 per share, exercisable only on a net share settlement basis (the "Warrants"), for net proceeds of $236.4 million, net of issuance costs.

In the fourth quarter of 2017, we redeemed $150.0 million of the $600.0 million aggregate principal amount outstanding of 7.50% Senior Notes due 2020 (the "7.50% Senior Notes"). The proceeds for the redemption were primarily from the Utica and Marcellus divestitures discussed above.

During 2017, the borrowing base under our revolving credit facility was increased from $600.0 million to $900.0 million primarily as a result of our continued development of our Eagle Ford and Delaware Basin assets as well as our ExL Acquisition. The $900.0 million borrowing base in place at December 31, 2017 was supported solely by the reserves of our Eagle Ford and Delaware Basin assets.

See "Note 6. Long-Term Debt", "Note 9. Preferred Stock and Warrants" and "Note 10. Shareholders' Equity and Stock Based Compensation" of the Notes to our Consolidated Financial Statements for further details regarding the financings discussed above.

Production and proved reserves. Crude oil production in 2017 was 34,428 Bbls/d, an increase of 34% as compared to 25,745 Bbls/d in 2016, primarily driven by strong performance from our new wells in the Eagle Ford and Delaware Basin and the addition of production from our acquisition of oil and gas properties located in the Eagle Ford Shale from Sanchez Energy Corporation and SN Cotulla Assets, LLC, a subsidiary of Sanchez Energy Corporation, in the fourth quarter of 2016 (the "Sanchez Acquisition") and the ExL Acquisition in the third quarter of 2017. Total production in 2017 increased to 53,805 Boe/d from 42,276 Boe/d in 2016 primarily due to the same reasons discussed above.

At year-end 2017, our proved reserves of 261.7 MMBoe consist of 64% crude oil, 16% natural gas liquids and 20% natural gas. Our reserves increased 61.6 MMBoe, or 31%, from our year-end 2016 proved reserves of 200.2 MMBoe primarily as a result of our ongoing drilling program in the Eagle Ford and the Delaware Basin and the ExL Acquisition described below. The following is a summary of the Company's proved reserves as of December 31, 2017 and 2016. See "—Additional Oil and Gas Disclosures —Proved Oil and Gas Reserves" for further details of our proved reserves.

	Proved Reserves	
	December 31, 2017	December 31, 2016
Region	(MMBoe)	
Eagle Ford [(1)]	167.0	162.3
Delaware Basin	90.9	11.7
Niobrara [(2)]	3.8	2.7
Marcellus	—	21.8
Utica and other	—	1.7
Total	261.7	200.2

(1) Included in the December 31, 2017 proved reserves are 10.9 MMBoe associated with a portion of our assets in the Eagle Ford that were divested in January 2018.
(2) In January 2018, we closed on the divestiture of substantially all of our Niobrara assets.

Recent Developments

7.50% Senior Notes. In January 2018, we called for redemption a total of $320.0 million aggregate principal amount of the outstanding 7.50% Senior Notes. The proceeds for these redemptions were primarily from the Niobrara and Eagle Ford Shale divestitures discussed above. After these redemptions, we will have $130.0 million aggregate principal amount of 7.50% Senior Notes outstanding.

Preferred Stock. In January 2018, we redeemed 50,000 of the shares of Preferred Stock, representing 20% of the issued and outstanding Preferred Stock, for $50.5 million, which consisted of $1,000.00 per share of Preferred Stock redeemed, plus accrued and unpaid dividends. After this redemption, we will have 200,000 shares of Preferred Stock outstanding.

Borrowing Base. In January 2018, as a result of the divestiture in the Eagle Ford Shale discussed above, our borrowing base under our revolving credit facility was reduced from $900.0 million to $830.0 million; however, the elected commitment amount remained unchanged at $800.0 million.

See "Note 15. Subsequent Events (Unaudited)" of the Notes to our Consolidated Financial Statements for further details of these recent developments.

2018 Drilling, Completion, and Infrastructure Capital Expenditure Plan. Our 2018 drilling, completion, and infrastructure capital expenditure plan is currently $750.0 million to $800.0 million. This incorporates an assumed double-digit increase in oilfield service costs as well as operating two drilling rigs in the Eagle Ford Shale and three to four drilling rigs in the Delaware Basin during 2018, as well as two to three completion crews during the year. We intend to finance our 2018 capital expenditure plan primarily from cash flow from operations and our senior secured revolving credit facility as well as other sources described in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." Our capital expenditure plan has the flexibility to adjust, should the commodity price environment change.

The following is a summary of our actual capital expenditures for 2017 and our planned capital expenditures for 2018:

	Capital Expenditures	
	2018 Plan [1]	2017 Actual
	(In millions)	
Drilling, completion, and infrastructure		
Eagle Ford	$439.0	$464.0
Delaware Basin	336.0	160.2
All other regions	—	27.8
Total drilling, completion, and infrastructure	775.0	652.0 [2]
Leasehold and seismic [3]	—	65.4
Total [4]	$775.0	$717.4

(1) Represents the midpoint of our 2018 drilling, completion, and infrastructure capital expenditure plan of $750.0 million to $800.0 million.
(2) Includes amounts related to the divested assets in the Utica, Marcellus, Niobrara and Eagle Ford of approximately $30.2 million, which consists of drilling and completion capital expenditures incurred between the effective date and close date of the divestitures.
(3) In the second quarter of 2017, Carrizo disclosed that it was no longer providing guidance for leasehold and seismic capital expenditures given the limited visibility and highly discretionary nature of this spending.
(4) Our capital expenditure plan and the actual capital expenditures exclude acquisitions of oil and gas properties, capitalized general and administrative expense, interest expense and asset retirement costs.

Business Strategy & Competitive Strengths

Our objective is to increase value through the execution of a business strategy focused on growth through the drill-bit complimented by opportunistic acquisitions of oil and gas properties, while maintaining a sound financial position. Key elements of our business strategy and competitive strengths which will support our efforts to successfully execute our business strategy include:

- *Pursue development of high-quality resource plays.* We pursue a growth strategy in crude oil plays primarily driven by the attractive relative economics associated with our core positions. All of our 2018 drilling, completion, and infrastructure capital expenditure plan is currently directed towards opportunities that we believe are predominantly prospective for crude oil development. We follow a disciplined approach to drilling wells by applying proven horizontal drilling and hydraulic fracturing technology. Additionally, we rely on advanced technologies, such as 3-D seismic and micro-seismic analysis, to better define geologic risk and enhance the results of our drilling efforts. Our successful drilling program has significantly de-risked our acreage positions in key resource plays.

  We continue to focus our capital program on resource plays where individual wells tend to have lower risk, such as our operations in the Eagle Ford and, more recently, the Delaware Basin, two of the highest return plays in North America. Additionally, we continue to take advantage of opportunities to expand our core positions through leasehold acquisitions as evidenced by the ExL Acquisition described below.

- *Operational efficiency and control.* We emphasize efficiencies to lower our costs to find, develop and produce our oil and gas reserves. This includes concentrating on our core areas, which allows us to optimize drilling and completion techniques as well as benefit from economies of scale. In addition, as we operate a significant percentage of our properties as well as maintain a minimal level of drilling commitments in order to hold acreage, the majority of our capital expenditure plan is discretionary, allowing us the ability to reallocate or adjust the level of our spending in response to changes in market conditions. For example, we have allocated a larger portion of our 2018 capital expenditure plan as compared to our 2017 capital expenditures to the Delaware Basin primarily as a result of the ExL Acquisition, while maintaining our continued development in the Eagle Ford.

  As of December 31, 2017, we operated approximately 91% of the wells in the Eagle Ford and the Delaware Basin in which we held an interest. We held an average working interest of approximately 88% in these operated wells. Our significant operational control, as well as our manageable leasehold obligations, provides us with the flexibility to align capital expenditures with cash flow and control our costs as we transition to an advanced development mode in key plays. As a further result of our operational control, we are generally able to adjust drilling plans in response to changes in commodity prices.

- *Significant growth potential.* Our management has continued to focus on high-quality resource plays by expanding positions and completing non-core asset sales. We have developed a significant inventory of future oil-focused drilling locations, primarily in our well-established positions in the Eagle Ford and the Delaware Basin. As of December 31, 2017, we owned leases covering approximately 195,289 gross (145,233 net) acres in these areas. See "—Acreage Data" for further details. Approximately 58% of our estimated proved reserves at December 31, 2017 were undeveloped.

- *Maintain our financial flexibility.* We are committed to preserving our financial flexibility. We have historically funded our capital program with a combination of cash generated from operations, proceeds from the divestiture of assets, proceeds from sales of securities, borrowings under our revolving credit facility and proceeds, payments or carried interest from our joint ventures. See "—General Overview" for further details of the redemptions of our 7.50% Senior Notes.

  We maintain a financial profile that provides operational flexibility, and our capital structure provides us with the ability to execute our business plan. Our financial profile is designed to allow us to withstand prolonged periods of low commodity prices, but also provides the ability to accelerate activity as commodity prices recover. As of February 23, 2018, we had $141.0 million of outstanding borrowings under our revolving credit facility, with an elected commitment amount of $800.0 million, have no near-term debt maturities, and use commodity derivative instruments to reduce our exposure to commodity price volatility. We attempt to limit our exposure to volatility in commodity prices by actively hedging a portion of our forecast crude oil, NGL, and natural gas production. Our current long-term strategy is to manage exposure to commodity price volatility to achieve a more predictable level of cash flows to support current and future capital expenditure plans.

- *Experienced management and professional workforce.* We have an experienced staff, both employees and contractors, of oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, production and reservoir engineers and technical support staff. We believe our experience and expertise, particularly as they relate to successfully identifying and developing resource plays, is a competitive advantage.

  We believe we have developed a technical advantage from our extensive experience drilling approximately 1,000 horizontal wells in various resource plays, which has allowed our management, technical staff and field operations teams to gain significant experience in resource plays and create highly efficient drilling and completion operations. We now leverage this advantage in our existing, as well as any prospective, shale trends. We plan to focus substantially all of our 2018 capital expenditures in the Eagle Ford and the Delaware Basin.

Exploration and Operation Approach

Our exploration strategy in our shale resource plays has been to accumulate significant leasehold positions in areas with known shale thickness and thermal maturity in the proximity of known or emerging pipeline infrastructures. A component of our exploration strategy is to first identify and acquire surface tracts or "well pads" from which multiple wells can be drilled. We then seek to acquire contiguous lease blocks in the areas immediately adjacent to these well pads that can be developed quickly. If conditions warrant, we next acquire 3-D seismic data over these leases to assist in well placement and development optimization. Finally, we form drilling units and utilize sophisticated horizontal drilling, multi-stage simultaneous hydraulic fracturing programs and micro-seismic techniques designed to maximize the production rate and recoverable reserves from a unit area.

We strive to achieve a balance between acquiring acreage, seismic data (2-D and 3-D) and timely project evaluation through the drillbit to ensure that we minimize the costs to test for commercial reserves while building a significant acreage position. Our first exploration wells in these trends are a limited number of horizontal wells, because they allow us to evaluate thermal maturity and rock property data, while also permitting us to test various completion techniques without incurring the cost of drilling a substantial number of horizontal wells. As discussed above, our primary focus is on crude oil to take advantage of what we believe are the attractive relative economics associated with this commodity.

We maintain a flexible and diversified approach to project identification by focusing on the estimated financial results of a project area rather than limiting our focus to any one method or source for obtaining leads for new project areas. Additionally, we monitor competitor activity and review outside prospect generation by small, independent "prospect generators." We complement our exploratory drilling portfolio through the use of these outside sources of prospect generation and typically retain operator rights. Specific drill-sites are typically chosen by our own geoscientists or, in environmentally sensitive areas, are dictated by available leases.

Our management team has extensive experience in the development and management of exploration and development projects. We believe that the experience we have gained drilling and completing horizontal wells in multiple basins and the experience of our management team in the development, processing and analysis of 3-D projects and data, will play a significant part in our future success.

We generally seek to obtain operator rights and control over field operations, and in particular seek to control decisions regarding drilling and completion methods. As of December 31, 2017, we operated 702 gross (563.7 net) productive oil and gas wells. We generally seek to control operations for most new exploration and development, taking advantage of our technical staff's experience in horizontal drilling and hydraulic fracturing. For example, during 2017, we operated 91% of the wells drilled in the Eagle Ford and the Delaware Basin where we incurred approximately 96% of our 2017 drilling, completion and infrastructure capital expenditures.

Working Interest and Drilling in Project Areas

The actual working interest we will ultimately own in a well will vary based upon several factors, including the risk of each well relative to our strategic goals, activity levels and capital availability. From time to time some fraction of these wells may be sold to industry partners either on a prospect by prospect basis or a program basis. In addition, we may also contribute acreage to larger drilling units thereby reducing prospect working interest. We have, in the past, retained less than 100% working interest in our drilling prospects. References to our interests are not intended to imply that we have or will maintain any particular level of working interest.

Summary of 2017 Proved Reserves, Production and Drilling by Area

	Eagle Ford	Delaware Basin	Niobrara (1)	Other	Total
Proved reserves by product					
Crude oil (MMBbls)	124.2	40.4	2.8	—	167.4
NGLs (MMBbls)	21.7	20.4	0.5	—	42.6
Natural gas (Bcf)	126.7	180.5	3.3	—	310.5
Total proved reserves (MMBoe)	167.0 (2)	90.9	3.8	—	261.7
Proved reserves by classification (MMBoe)					
Proved developed	77.6	27.6	3.8	—	109.0
Proved undeveloped	89.4	63.3	—	—	152.7
Total proved reserves	167.0 (2)	90.9	3.8	—	261.7
Percent of total reserves	64%	35%	1%	—%	100%
2017 production (MMBoe)	13.8 (3)	2.5	0.9	2.4	19.6
Percent of total production	70%	13%	5%	12%	100%

	Eagle Ford (4)		Delaware Basin		Niobrara (1)		Other		Total	
Operated Well Data	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Year Ended December 31, 2017										
Drilled	91	77.5	14	11.0	—	—	—	—	105	88.5
Completed	88	80.9	14	11.6	—	—	—	—	102	92.5
December 31, 2017										
Drilled but uncompleted	37	31.3	6	4.6	—	—	—	—	43	35.9
Producing	538	477.9	34	28.1	130	57.7	—	—	702	563.7

(1) In January 2018, we closed on the divestiture of substantially all of our Niobrara assets.
(2) Included in the December 31, 2017 proved reserves are 10.9 MMBoe associated with a portion of our assets in the Eagle Ford that were divested in January 2018.
(3) Included in 2017 production is 1.3 MMBoe associated with a portion of our assets in the Eagle Ford that were divested in January 2018.
(4) Included in the well counts above are 5 gross (3.8 net) drilled wells, 5 gross (3.8 net) completed wells, and 96 gross (77.4 net) producing wells associated with a portion of our assets in the Eagle Ford that were divested in January 2018.

Regional Overview

Eagle Ford Shale

The Eagle Ford is our most significant operational area. Our core Eagle Ford properties are located in LaSalle County and, to a lesser extent, in McMullen, Frio and Atascosa counties in Texas. As of December 31, 2017, we held interests in approximately 127,123 gross (103,116 net) acres (97,220 gross (79,612 net) acres after adjusting for the divestiture of a portion of our assets in the Eagle Ford which closed in January 2018 described below). We currently plan for approximately 57% of our 2018 drilling, completion, and infrastructure capital expenditure plan to be directed towards opportunities in the Eagle Ford where we currently expect to operate two drilling rigs during 2018.

On December 11, 2017, we entered into a purchase and sale agreement with EP Energy E&P Company, L.P. to sell a portion of our assets in the Eagle Ford for an agreed upon price of $245.0 million, with an effective date of October 1, 2017, subject to adjustment and customary terms and conditions. On December 11, 2017, we received $24.5 million as a deposit, on January 31, 2018, we received $211.7 million at closing, subject to post-closing adjustments, and on February 16, 2018, we received $10.0 million for leases that were not conveyed at closing, for aggregate net proceeds of $246.2 million, which included preliminary purchase price adjustments primarily related to the net cash flows from the effective date to the closing date.

GAIL Joint Venture. In September 2011, we entered into joint venture arrangements with GAIL GLOBAL (USA) INC. ("GAIL"), a wholly owned subsidiary of GAIL (India) Limited. Under this arrangement, GAIL acquired a 20% interest in certain oil and gas properties in the Eagle Ford and an option to purchase a 20% share of acreage acquired by us after the closing located in specified areas adjacent to the initially purchased areas. We generally serve as operator of the GAIL joint venture properties. As of December 31, 2017, acres included in the GAIL joint venture cover approximately 21% of our total Eagle Ford acreage (14% after adjusting for the divestiture of a portion of our assets in the Eagle Ford which closed in January 2018).

Delaware Basin

During 2014, we began to build an acreage position in the Delaware Basin in Culberson and Reeves counties, Texas, targeting the Wolfcamp Formation. As of December 31, 2017, we held interests in approximately 68,166 gross (42,117 net) acres in the Delaware Basin. In the third quarter of 2017, we closed on the ExL Acquisition which added 16,508 net acres to our portfolio. We currently plan for approximately 43% of our 2018 drilling, completion, and infrastructure capital expenditure plan to be directed towards opportunities in the Delaware Basin where we currently expect to operate three to four drilling rigs during 2018.

Non-Core Divestitures

Niobrara Formation. During the fourth quarter of 2017, we entered into a purchase and sale agreement to sell substantially all of our assets in the Niobrara Formation for an agreed upon price of $140.0 million, with an effective date of October 1, 2017, subject to customary purchase price adjustments. On November 20, 2017, we received $14.0 million as a deposit and on January 19, 2018, we received $122.6 million at closing, subject to post-closing adjustments, for aggregate net proceeds of $136.6 million, which included preliminary purchase price adjustments primarily related to the net cash flows from the divested wells from the effective date to the closing date. We also could receive contingent consideration of $5.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2020. In conjunction with the sale, our joint ventures terminated with OIL India (USA) Inc. and IOCL (USA) Inc., wholly owned subsidiaries of OIL India Ltd. and Indian Oil Corporation Ltd., respectively, and Haimo Oil & Gas LLC, a wholly owned subsidiary of Lanzhou Haimo Technologies Co. Ltd.

Marcellus Shale. In the fourth quarter of 2017, we closed on the divestiture of substantially all of our assets in the Marcellus Shale to BKV Chelsea, LLC, a subsidiary of Kalnin Ventures LLC, for an agreed upon price of $84.0 million, with an effective date of April 1, 2017, subject to customary purchase price adjustments. On October 5, 2017, we received $6.3 million into escrow as a deposit and on November 21, 2017, we received $67.6 million at closing, subject to post-closing adjustments, for aggregate net proceeds of $73.9 million, which included preliminary purchase price adjustments primarily related to the net cash flows from the divested wells from the effective date to the closing date. In addition, we could receive contingent consideration of $3.0 million per year with a cap of $7.5 million if natural gas prices exceed specified thresholds for each of the years of 2018 through 2020.

Simultaneous with the signing of the Marcellus Shale transaction discussed above, our existing joint venture partner in the Marcellus Shale, Reliance Marcellus II, LLC ("Reliance"), a wholly owned subsidiary of Reliance Holding USA, Inc. and an affiliate of Reliance Industries Limited, entered into a purchase and sale agreement with BKV Chelsea, LLC to sell its interest in the same oil and gas properties. Simultaneous with the closing of these Marcellus Shale sale transactions, the agreements governing the Reliance joint venture were assigned to the buyer and, after giving effect to such transactions, the Reliance joint venture was terminated except for limited post-closing obligations.

Utica Shale. In the fourth quarter of 2017, we closed on the divestiture of substantially all of our assets in the Utica Shale, located primarily in Guernsey County, Ohio, for an agreed upon price of $62.0 million, with an effective date of April 1, 2017, subject to customary purchase price adjustments. On August 31, 2017, we received $6.2 million from the buyer as a deposit, on November 15, 2017, we received $54.4 million at closing, subject to post-closing adjustments, and on December 28, 2017, we received an additional $2.5 million, for aggregate net proceeds of $63.1 million, which included preliminary purchase price adjustments primarily related to the net cash flows from the divested wells from the effective date to the closing date. In addition, we could receive contingent consideration of $5.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2020.

Additional Oil and Gas Disclosures

Proved Oil and Gas Reserves

The following table sets forth our estimated net proved reserves and PV-10 as of December 31, 2017 that were prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent third party reserve engineers. For further information concerning Ryder Scott's estimates of our proved reserves as of December 31, 2017, see the reserve report included as an exhibit to this Annual Report on Form 10-K.

The prices used in the calculation of our estimated proved reserves and PV-10 as of December 31, 2017 were based on the average realized prices for sales of crude oil, NGLs and natural gas on the first calendar day of each month during the 12-month period prior to December 31, 2017 ("12-Month Average Realized Price") in accordance with SEC rules and were $49.87 per Bbl of crude oil, $19.78 per Bbl of NGLs and $2.96 per Mcf of natural gas.

For further information concerning the present value of estimated future net revenues from these proved reserves, see "Note 2. Summary of Significant Accounting Policies" and "Note 16. Supplemental Disclosures about Oil and Gas Producing Activities (Unaudited)" of the Notes to our Consolidated Financial Statements. See also "—Other Reserve Matters" below for further discussion.

Summary of Proved Oil and Gas Reserves as of December 31, 2017

	Crude Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (In millions)
Proved developed	69,632	17,447	131,355	108,972	$1,621.0
Proved undeveloped	97,742	25,151	179,115	152,745	$1,017.4
Total Proved	167,374	42,598	310,470	261,717	$2,638.4

Reconciliation of Standardized Measure of Discounted Future Net Cash Flows (GAAP) to PV-10 (Non-GAAP)

We believe that the presentation of PV-10 provides greater comparability when evaluating oil and gas companies due to the many factors unique to each individual company that impact the amount and timing of future income taxes. In addition, we believe that PV-10 is widely used by investors and analysts as a basis for comparing the relative size and value of our proved reserves to other oil and gas companies. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP. The definition of PV-10 as defined in "Item 1. Business—Glossary of Certain Industry Terms" may differ significantly from the definitions used by other companies to compute similar measures. As a result, PV-10 as defined may not be comparable to similar measures provided by other companies. A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented below. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

	As of December 31, 2017 (In millions)
Standardized measure of discounted future net cash flows (GAAP)	$2,465.1
Add: present value of future income taxes discounted at 10% per annum	173.3
PV-10 (Non-GAAP)	$2,638.4

Proved Undeveloped Reserves

The following table provides a summary of the changes in our proved undeveloped reserves ("PUDs") for the year ended December 31, 2017.

	Crude Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
PUDs as of December 31, 2016	77,256	14,550	100,391	108,538
Extensions and discoveries	45,995	12,862	92,546	74,281
Purchases of reserves in place	11,071	3,204	34,915	20,094
Divestitures of reserves in place	—	—	(43,782)	(7,297)
Removed due to changes in development plan	(10,670)	(1,851)	(10,684)	(14,302)
Revisions of previous estimates	(5,655)	490	30,191	(133)
Converted to proved developed reserves	(20,255)	(4,104)	(24,462)	(28,436)
PUDs as of December 31, 2017	97,742	25,151	179,115	152,745

Extensions and discoveries of 74.3 MMBoe were due to additional offset locations associated with our drilling program, of which 37.5 MMBoe were in the Eagle Ford and 36.8 MMBoe were in the Delaware Basin. We incurred $22.8 million during 2017 for certain of these PUD locations that were drilled but uncompleted as of December 31, 2017.

Purchases of reserves in place of 20.1 MMBoe were due to the ExL Acquisition in the third quarter of 2017.

Divestitures of reserves in place of 7.3 MMBoe were related to the sale of our assets in the Marcellus Shale in the fourth quarter of 2017. We had no proved undeveloped reserves associated with the Utica Shale.

We removed 14.3 MMBoe of PUDs in the Eagle Ford due to changes in our previously approved development plan, which resulted in the timing of development for certain PUD locations to move beyond five years from initial booking. The drivers of the changes in our previously approved development plan were the recent ExL Acquisition and the move to a more efficient development plan which includes drilling and completing larger pads.

Revisions of previous estimates of 0.1 MMBoe included 5.8 MMBoe of negative revisions due to a downward shift of the type curve for certain PUD locations in the Eagle Ford partially offset by 5.7 MMBoe of positive revisions due to well performance in Marcellus which occurred prior to the sale in November 2017.

We converted 28.4 MMBoe of PUD reserves that were booked as PUDs as of December 31, 2016 to proved developed during 2017, of which 27.7 MMBoe were in the Eagle Ford, at a total cost of $310.2 million, or $10.92 per Boe. We converted an additional 11.4 MMBoe of PUD reserves that were booked as PUDs during 2017 to proved developed, of which 7.7 MMBoe were in the Delaware Basin, at a total cost of $129.4 million, or $11.35 per Boe. We also incurred $47.6 million during 2017 on PUD locations that were drilled but uncompleted as of December 31, 2017 that were booked as PUDs as of December 31, 2016.

As of December 31, 2017, we had 17.0 MMBoe of PUD reserves associated with wells that were drilled but uncompleted, all of which are scheduled to be completed in 2018, with the majority scheduled to be completed during the first half of 2018. We expect to incur $139.8 million of capital expenditures to complete these wells.

At December 31, 2017, we did not have any reserves that have remained undeveloped for five or more years since the date of their initial booking and all PUD locations are scheduled to be developed within five years of their initial booking.

Qualifications of Technical Persons

In accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and the guidelines established by the Securities and Exchange Commission (“SEC”), Ryder Scott estimated 100% of our proved reserves as of December 31, 2017, 2016, and 2015 as presented in this Annual Report on Form 10-K. The technical persons responsible for preparing the reserves estimates meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott does not own an interest in our properties and is not employed on a contingent fee basis.

Our internal reserve engineers each have over 25 years of experience in the petroleum industry and extensive experience in the estimation of reserves and the review of reserve reports prepared by third party engineering firms. The reserve reports are also reviewed by senior management, including the Chief Executive Officer, who is a registered petroleum engineer and holds a B.S. in Mechanical Engineering and the Chief Operating Officer, who holds a B.S. in Petroleum Engineering.

Internal Controls Over Reserve Estimation Process

The primary inputs to the reserve estimation process are comprised of technical information, financial data, production data, and ownership interests. All field and reservoir technical information, which is updated annually, is assessed for validity when the internal reserve engineers hold technical meetings with our geoscientists, operations, and land personnel to discuss field performance and to validate future development plans. The other inputs used in the reserve estimation process, including, but not limited to, future capital expenditures, commodity price differentials, production costs, and ownership percentages are subject to internal controls over financial reporting and are assessed for effectiveness annually.

Our internal reserve engineers work closely with Ryder Scott to ensure the integrity, accuracy, and timeliness of the data furnished to Ryder Scott for use in their reserves estimation process. Our internal reserve engineers meet regularly with Ryder Scott to review and discuss methods and assumptions used in Ryder Scott’s preparation of the year-end reserves estimates. The internal reserve engineers review the inputs and assumptions made in the reserves estimates prepared by Ryder Scott and assess them for reasonableness.

Specific internal control procedures include, but are not limited to, the following:

- Review by our internal reserve engineers of all of our reported proved reserves at the close of each quarter, including review of all additions to PUD reserves
- Quarterly updates by our senior management to our Board of Directors regarding operational data, including production, drilling and completion activity and any significant changes in our reserves estimates
- Quarterly and annual preparation of a reserve reconciliation that is reviewed by members of our senior management
- Annual review by our senior management of our year-end reserves estimates prepared by Ryder Scott
- Annual review by our senior management and Board of Directors of our multi-year development plan and approval by the Board of Directors of our capital expenditure plan
- Review by our senior management of changes, if applicable, in our previously approved development plan

Other Reserve Matters

No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC. The reserves data set forth in this Annual Report on Form 10-K represents only estimates. See “Item 1A. Risk Factors—Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future.”

Our future oil and gas production is highly dependent upon our level of success in finding or acquiring additional reserves. See “Item 1A. Risk Factors—We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future.” Also, the failure of an operator of our wells to adequately perform operations, or such operator’s breach of the applicable agreements, could adversely impact us. See “Item 1A. Risk Factors—We cannot control the activities on properties we do not operate.”

The prices used in calculating the estimated future net revenue attributable to proved reserves do not necessarily reflect market prices for oil and gas production. See “Item 1A. Risk Factors—Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future.” There can be no assurance that all of the proved reserves will be produced and sold within the periods indicated, that the assumed prices will actually be realized for such production or that existing contracts will be honored or judicially enforced.

Oil and Gas Production, Prices and Costs

The following table sets forth certain information regarding the production volumes, average realized prices and average production costs associated with our sales of oil and gas for the periods indicated.

	Years Ended December 31,		
	2017	**2016**	**2015**
Total production volumes [1]			
Crude oil (MBbls)	12,566	9,423	8,415
NGLs (MBbls)	2,327	1,788	1,352
Natural gas (MMcf)	28,472	25,574	21,812
Total barrels of oil equivalent (MBoe)	19,639	15,473	13,402
Daily production volumes by product [1]			
Crude oil (Bbls/d)	34,428	25,745	23,054
NGLs (Bbls/d)	6,376	4,885	3,705
Natural gas (Mcf/d)	78,006	69,873	59,758
Total barrels of oil equivalent per day (Boe/d)	53,805	42,276	36,719
Daily production volumes by region (Boe/d) [1]			
Eagle Ford	37,825	30,664	26,377
Delaware Basin	6,713	1,115	104
Niobrara	2,558	2,931	2,957
Marcellus	6,122	6,329	5,850
Utica and other	587	1,237	1,431
Total barrels of oil equivalent (Boe/d)	53,805	42,276	36,719
Average realized prices			
Crude oil ($ per Bbl)	$50.39	$40.12	$44.69
NGLs ($ per Bbl)	20.37	12.54	11.54
Natural gas ($ per Mcf)	2.29	1.69	1.72
Total average realized price ($ per Boe)	$37.98	$28.67	$32.03
Average production costs ($ per Boe) [2]	$7.12	$6.38	$6.72

(1) In the fourth quarter of 2017, we closed on divestitures of substantially all of our assets in the Utica and Marcellus and in the first quarter of 2018, we closed on divestitures of substantially all of our assets in the Niobrara and a portion of our assets in the Eagle Ford. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" of the Notes to our Consolidated Financial Statements for further details of these transactions.

(2) Includes lease operating expenses but excludes production taxes and ad valorem taxes.

Drilling Activity

The following table sets forth our operated and non-operated drilling activity for the years ended December 31, 2017, 2016 and 2015. In the table, "gross" refers to the total wells in which we have a working interest and "net" refers to gross wells multiplied by our working interest therein.

	Years Ended December 31,					
	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells - Productive	47 (1)	7.1 (1)	29	4.5	77	19.5
Exploratory Wells - Nonproductive	—	—	—	—	—	—
Development Wells - Productive	102 (2)	89.7 (2)	81	73.5	65	55.4
Development Wells - Nonproductive	—	—	—	—	—	—

(1) Includes 37 gross (6.3 net) productive exploratory wells which were part of the divestitures of substantially all of our assets in the Utica, Marcellus and Niobrara, as well as a portion of our assets in the Eagle Ford.
(2) Includes 5 gross (3.8 net) productive development wells which were part of the divestiture of a portion of our assets in the Eagle Ford.

As of December 31, 2017, we had 55 gross (40.2 net) operated and non-operated wells in various stages of drilling, completion or waiting on completion that are not included in the table above.

Productive Wells

The following table sets forth the number of productive crude oil and natural gas wells in which we owned an interest as of December 31, 2017.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil (1)	692	555.7	326	28.0	1,018	583.7
Natural gas (2)	10	8.0	17	0.6	27	8.6
Total	702	563.7	343	28.6	1,045	592.3

(1) Includes 217 gross (127.9 net) and 296 gross (24.7 net) operated and non-operated wells, respectively, which were part of the divestitures of substantially all of our assets in the Niobrara as well as a portion of our assets in the Eagle Ford.
(2) Includes 9 gross (7.2 net) operated productive natural gas wells which were part of the divestiture of a portion of our assets in the Eagle Ford.

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped acreage as of December 31, 2017. Developed acreage refers to acreage on which wells have been completed to a point that would permit production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

	Developed Acreage		Undeveloped Acreage		Total Acreage (1)		Percent of Net Undeveloped Acreage Expiring		
	Gross	Net	Gross	Net	Gross	Net	2018	2019	2020
Eagle Ford	102,387	84,806	24,736	18,310	127,123	103,116	30% (2)	18% (3)	9% (3)
Delaware Basin	24,725	16,789	43,441	25,328	68,166	42,117	23% (4)	23% (3)	44% (3)
Niobrara (5)	40,435	14,603	54,798	16,027	95,233	30,630	8%	14%	12%
Other (6)	1,174	437	60,980	45,421	62,154	45,858	7%	9%	—%
Total	168,721	116,635	183,955	105,086	352,676	221,721	15%	15%	14%

(1) Total acreage as of December 31, 2017 includes 29,903 gross (23,504 net) acres which were part of our divestiture in the Eagle Ford.
(2) Of the approximate 5,500 net undeveloped acres scheduled to expire in 2018 in Eagle Ford, approximately 2,600 net undeveloped acres were part of our divestiture in the Eagle Ford. The remaining net undeveloped acres which are set to expire do not have any associated proved undeveloped reserves.
(3) Proved undeveloped reserves associated with the net undeveloped acres scheduled to expire in 2019 and 2020 are scheduled to be developed prior to the acreage expiration.

(4) Of the approximate 5,800 net undeveloped acres scheduled to expire in 2018 in the Delaware Basin, approximately 3,600 net undeveloped acres will be held due to development activity or extended by lease extension payments.
(5) In January 2018, we closed on the divestiture of substantially all of our Niobrara assets.
(6) Other includes non-core acreage principally located in Texas, Wyoming, West Virginia, Ohio, Pennsylvania, Kentucky, and Illinois, where we do not currently have planned capital expenditures. There are insignificant costs for unproved property and no proved undeveloped reserves associated with the non-core net undeveloped acreage.

Our lease agreements generally terminate if producing wells have not been drilled on the acreage within their primary term or an extension thereof (a period that can be from three to five years depending on the area). The percentage of net undeveloped acreage expiring in 2018, 2019, and 2020 assumes that no producing wells have been drilled on acreage within their primary term or have been extended. We manage our lease expirations to ensure that we do not experience unintended material expirations. Our leasehold management efforts include scheduling drilling in order to hold leases by production or timely exercising our contractual rights to extend the terms of leases by continuous operations or the payment of lease extension payments and delay rentals. We may choose to allow some leases to expire that are no longer part of our development plans.

The proved undeveloped reserves associated with acreage expiring over the next three years are not material to the Company.

Marketing

Typically, our production is sold at the wellhead to unaffiliated third party purchasers. Crude oil is sold at prices based on posted prices or NYMEX plus or minus market differentials for the respective area. Natural gas and NGLs are sold under contract at a negotiated price which is based on the market price for the area or at published prices for specified locations or pipelines and then discounted by the purchaser back to the wellhead based upon a number of factors normally considered in the industry (such as distance from the well to the central market location, well pressure, quality of natural gas and prevailing supply and demand conditions). We have made the strategic decision to sell as much of our natural gas production at the wellhead as possible, so that we can concentrate our efforts and resources on exploration and production which we believe are more consistent with our competitive expertise, rather than natural gas gathering, processing, transportation and marketing. In each case, we sell at competitive market prices based on a differential to several market locations. In instances of depressed oil and gas prices, we may elect to shut-in wells until commodity prices are more favorable. We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and gas we produce because we believe other purchasers are available in all our areas of operations.

Our marketing objective is to receive competitive wellhead prices for our product. There are a variety of factors that affect the market for oil and gas generally, including:

- demand for oil and gas;
- the extent of supply of oil and gas and, in particular, domestic production and imports;
- the proximity and capacity of natural gas pipelines and other transportation facilities;
- the marketing of competitive fuels; and
- the effects of state and federal regulations on oil and gas production and sales.

See “Item 1A. Risk Factors—Oil and gas prices are highly volatile, and continued low oil and gas prices or further price decreases will negatively affect our financial position, planned capital expenditures and results of operations,” “—We are subject to various environmental risks and governmental regulations, including those relating to benzene emissions, hydraulic fracturing and global climate change, and future regulations may be more stringent resulting in increased operating costs and decreased demand for the oil and gas that we produce,” and “—If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases. Our ability to sell oil and natural gas and receive market prices for our oil and natural gas may be adversely affected by pipeline and gathering system capacity constraints.”

In addition to selling our production at the wellhead, we work with various pipeline companies to procure and to assure capacity for our natural gas. For further discussion of this matter, see “Item 1A. Risk Factors—If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases. Our ability to sell oil and natural gas and receive market prices for our oil and natural gas may be adversely affected by pipeline and gathering system capacity constraints.” We have entered into various long-term gathering, processing, and transportation contracts with various parties which require us to deliver fixed, determinable quantities of production over specified periods of time. Certain of these contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under these commitments. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Contractual Obligations” and “Note 8. Commitments and Contingencies” of the Notes to our Consolidated Financial Statements for additional details regarding our financial commitments under these contracts.

Competition and Technological Changes

We encounter competition from other oil and gas companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Many of our competitors are large, well-established companies that have been engaged in the oil and gas business for much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. We may not be able to conduct our operations, evaluate and select suitable properties and consummate transactions successfully in this highly competitive environment.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Regulation

Oil and gas operations are subject to various federal, state, local and international environmental regulations that may change from time to time, including regulations governing oil and gas production and transportation, federal and state regulations governing environmental quality and pollution control and state limits on allowable rates of production by well or proration unit. These regulations may affect the amount of oil and gas available for sale, the availability of adequate pipeline and other regulated processing and transportation facilities and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an oversupply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of oil and gas, protect rights to produce oil and gas between owners in a common reservoir, control the amount of oil and gas produced by assigning allowable rates of production, provide nondiscriminatory access to common carrier pipelines and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted.

The following discussion summarizes the regulation of the United States oil and gas industry. We believe we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although we cannot assure you that this is or will remain the case. Moreover, those statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and any such changes or reinterpretations could materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Natural Gas and Oil Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels that:

- require permits for the drilling of wells;
- mandate that we maintain bonding requirements in order to drill or operate wells; and
- regulate the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, groundwater sampling requirements prior to drilling, the plugging and abandoning of wells and the disposal of fluids used in connection with operations.

Our operations are also subject to various conservation laws and regulations. These regulations govern the size of drilling and spacing units or proration units, setback rules, the density of wells that may be drilled in oil and gas properties and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states (including Texas) rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is primarily or exclusively voluntary, it may be more difficult to form units and therefore more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws that establish maximum rates of production from oil and gas wells generally prohibit the venting or flaring of natural gas and impose specified requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil and gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability. Because these laws and regulations are frequently expanded, amended and reinterpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas we produce and the manner in which our production is transported and marketed. Under the Natural Gas Act of 1938 ("NGA"), the Federal Energy Regulatory

Commission ("FERC") regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act (the "Decontrol Act") deregulated natural gas prices for all "first sales" of natural gas, including all of our sales of our own production. As a result, all of our domestically produced natural gas is sold at market prices, subject to the terms of any private contracts that may be in effect. The FERC's jurisdiction over interstate natural gas transportation, however, was not affected by the Decontrol Act.

Under the NGA, facilities used in the production or gathering of natural gas are exempt from the FERC's jurisdiction. We own certain natural gas pipelines that we believe satisfy the FERC's criteria for establishing that these are all gathering facilities not subject to FERC jurisdiction under the NGA. State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

One of our pipeline subsidiaries, Hondo Pipeline Inc., may exercise the power of eminent domain and is a regulated public utility within the meaning of Section 101.003 ("GURA") and Section 121.001 (the "Cox Act") of the Texas Utilities Code. Both GURA and the Cox Act prohibit unreasonable discrimination in the transportation of natural gas and authorize the Texas Railroad Commission to regulate gas transportation rates. However, GURA provides for negotiated rates with transportation, industrial or similar large-volume contract customers so long as neither party has an unfair negotiating advantage, the negotiated rate is substantially the same as that negotiated with at least two other customers under similar conditions, or sufficient competition existed when the rate was negotiated.

Although we do not own or operate any pipelines or facilities that are directly regulated by the FERC, its regulations of third-party pipelines and facilities could indirectly affect our ability to market our production. Beginning in the 1980s, the FERC initiated a series of major restructuring orders that required pipelines, among other things, to perform open access transportation, "unbundle" their sales and transportation functions, and allow shippers to release their pipeline capacity to other shippers. As a result of these changes, sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. It remains to be seen, however, what effect the FERC's other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities.

In the past, Congress has been very active in the area of natural gas regulation. However, the more recent trend has been in favor of deregulation or "lighter handed" regulation and the promotion of competition in the gas industry. In light of this increased reliance on competition, the Energy Policy Act of 2005 amended the NGA to prohibit any forms of market manipulation in connection with the transportation, purchase or sale of natural gas. In addition to the regulations implementing these prohibitions, the FERC has established new regulations that are intended to increase natural gas pricing transparency through, among other things, expanded dissemination of information about the availability and prices of gas sold and new regulations that require both interstate pipelines and certain non-interstate pipelines to post daily information regarding their design capacity and daily scheduled flow volumes at certain points on their systems. The Energy Policy Act of 2005 also significantly increased the penalties for violations of the NGA and the FERC's regulations to up to $1.0 million per day for each violation. This maximum penalty authority established by statute has been and will continue to be adjusted periodically to account for inflation.

Oil Price Controls and Transportation Rates

Our sales of crude oil, condensate and NGLs are not currently regulated and are made at market prices. The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to specified conditions and limitations. These regulations may tend to increase the cost of transporting crude oil and NGLs by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In December 2015, to implement the latest required five-yearly re-determination, the FERC established an upward adjustment in the index to track oil pipeline cost changes. For the five-year period beginning July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. Under FERC's regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. We are not able at this time to predict the effects of this indexing system or any new FERC regulations on the transportation costs associated with oil production from our oil producing operations.

There regularly are legislative proposals pending in the federal and state legislatures which, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by

Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, we cannot predict whether or to what extent the trend toward federal deregulation of the petroleum industry will continue, or what the ultimate effect on our sales of oil, gas and other petroleum products will be.

Environmental Regulations

Our operations are subject to numerous international, federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on specified lands within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from former operations, such as pit closure and plugging abandoned wells, and impose substantial liabilities for pollution resulting from production and drilling operations. The failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of investigatory or remedial obligations or the issuance of injunctions prohibiting or limiting the extent of our operations. Public interest in the protection of the environment has increased dramatically in recent years. The trend of applying more expansive and stricter environmental legislation and regulations to the oil and gas industry could continue, resulting in increased costs of doing business and consequently affecting our profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

We currently own or lease numerous properties that for many years have been used for the exploration and production of oil and gas. Although we believe that we have generally implemented appropriate operating and waste disposal practices, prior owners and operators of these properties may not have used similar practices, and hydrocarbons or other waste may have been disposed of or released on or under the properties we own or lease or on or under locations where such waste has been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other waste was not under our control. These properties and the waste disposed thereon may be subject to the federal Resource Conservation and Recovery Act ("RCRA"), the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), and analogous state laws as well as state laws governing the management of oil and gas waste. Under these laws, we could be required to remove or remediate previously disposed waste (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

We generate waste that may be subject to RCRA and comparable state statutes. The U.S. Environmental Protection Agency ("EPA") and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous waste. Furthermore, certain waste generated by our oil and gas operations that are currently exempt from treatment as "hazardous waste" may in the future be designated as "hazardous waste" and therefore become subject to more rigorous and costly operating and disposal requirements.

CERCLA, also known as the "Superfund" law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on specified classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These classes of persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Our operations may be subject to the Clean Air Act and comparable state and local requirements. In 1990 Congress adopted amendments to the Clean Air Act containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed and continue to develop regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Moreover, changes in environmental laws and regulations occur frequently, and stricter laws, regulations or enforcement policies could significantly increase our compliance costs. Further, stricter requirements could negatively impact our production and operations. For example, on October 1, 2015, EPA released a final rule tightening the primary and secondary NAAQS for ground-level ozone from its 2008 standard levels of 75 parts per billion ("ppb") to 70 ppb. The EPA may designate the areas in which we operate as nonattainment areas under this revised standard. States that contain any areas designated nonattainment, and any tribes that choose to do so, will be required to develop state implementation plans demonstrating how the area will attain the standard within a prescribed period of time. These plans may require the installation of additional equipment to control emissions. Similar initiatives could lead to more stringent air permitting, increased regulation and possible enforcement actions at the local, state, and federal levels.

Additionally, the EPA has established new air emission control requirements for natural gas and NGLs production, processing and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and National Emission Standards for Hazardous Air Pollutants ("NESHAPS") to address hazardous air pollutants frequently associated with gas production and processing activities. Among other things, these rules require the reduction of volatile organic compound emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. In addition, gas wells are required to use completion combustion device equipment (i.e., flaring) by October 15, 2012 if emissions cannot be directed to a gathering line. Further, the final rules under NESHAPS include maximum achievable control technology ("MACT") standards for "small" glycol dehydrators that are located at major sources of hazardous air pollutants and modifications to the leak detection standards for valves. In June 2016, the EPA published updates to new source performance standard requirements that would impose more stringent controls on methane and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. The EPA is currently reconsidering this rule and has proposed to stay its requirements. However, the rule currently remains in effect. Similarly in November 2016, the Bureau of Land Management ("BLM") issued rules requiring additional efforts by producers to reduce venting, flaring, and leaking of natural gas produced on federal and Native American lands. In December 2017, the BLM issued a final stay of the rules that temporarily suspends or delays their requirements until January 2019, while the BLM considers revising or rescinding the requirements. However, if these requirements go into effect, compliance may require modifications to certain of our operations, including the installation of new equipment to control emissions at the well site that could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as us, to prepare and implement spill prevention, control, countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners and operators of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. The OPA also requires owners and operators of offshore facilities that could be the source of an oil spill into federal or state waters, including wetlands, to post a bond, letter of credit or other form of financial assurance in amounts ranging from $10.0 million in specified state waters to $35.0 million in federal outer continental shelf waters to cover costs that could be incurred by governmental authorities in responding to an oil spill. These financial assurances may be increased by as much as $150.0 million if a formal risk assessment indicates that the increase is warranted. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities.

Our operations are also subject to the federal Clean Water Act ("CWA") and analogous state laws that impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as U.S. waters. Pursuant to the requirements of the CWA, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits or seek coverage under an EPA general permit. Like OPA, the CWA and analogous state laws relating to the control of water pollution provide varying civil and criminal penalties and liabilities for releases of petroleum or its derivatives into surface waters or into the ground. Similarly, the U.S. Congress has considered legislation to subject hydraulic fracturing operations to federal regulation and to require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. Please read "Item 1A. Risk Factors-We are subject to various environmental risks and governmental regulations, including those relating to benzene emissions, hydraulic fracturing and global climate change, and future regulations may be more stringent resulting in increased operating costs and decreased demand for the oil and gas that we produce."

The Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. Some of our operations are located in or near areas that may be designated as habitats for endangered or threatened species, such as the Attwater's prairie chicken. In these areas, we may be obligated to develop and implement plans to avoid potential adverse effects to protected species and their habitats, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could restrict drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we operate could result in increased costs of or limitations on our ability to perform operations and thus have an adverse effect on our business. We believe that we are in substantial compliance with the ESA, and we are not aware of any proposed listings that will affect our operations. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

The Safe Drinking Water Act ("SDWA") and comparable local and state provisions restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state's environmental authority. These regulations may increase the costs of compliance for some facilities. We believe that we substantially comply with the SDWA and related state provisions.

We also are subject to a variety of federal, state, local and foreign permitting and registration requirements relating to protection of the environment. We believe we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse effect on our financial position or results of operations.

Global Climate Change

There is increasing attention in the United States and worldwide being paid to the issue of climate change and the contributing effect of greenhouse gas ("GHG") emissions. The EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, regulates GHG emissions from certain large stationary sources under the Clean Air Act Prevention of Significant Deterioration ("PSD") and Title V permitting programs. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA also expanded its existing GHG emissions reporting rule to apply to the oil and gas source category, including oil and natural gas production facilities and natural gas processing, transmission, distribution and storage facilities. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO2 equivalent per year were required to report annual GHG emissions to EPA, for the first time by September 28, 2012. In addition, in June 2016, the EPA published updates to new source performance standard requirements that would impose more stringent controls on methane and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. The EPA is currently reconsidering this rule and has proposed to stay its requirements. However, the rule currently remains in effect.

The U.S. Congress has considered a number of legislative proposals to restrict GHG emissions and more than 20 states, either individually or as part of regional initiatives, have begun taking actions to control or reduce GHG emissions. Efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. However, in August of 2017, the United States informed the United Nations of its intent to withdraw from the Paris Agreement. The earliest possible effective withdrawal date from the Paris Agreement is November 2020.

While it is not possible at this time to predict how regulation that may be enacted to address GHG emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas.

In addition to the effects of future regulation, the meteorological effects of global climate change could pose additional risks to our operations in the form of more frequent and/or more intense storms and flooding, which could in turn adversely affect our cost of doing business.

Title to Properties

We believe we currently have satisfactory title to all of our producing properties in the specific areas in which we operate, except where failure to do so would not have a material adverse effect on our business and operations in such area, taken as a whole. For additional information, please see "Item 1A. Risk Factors—We may incur losses as a result of title deficiencies."

Customers

The following table presents customers that represent 10% or more of our total revenues for the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
	2017	**2016**	**2015**
Shell Trading (US) Company	69%	56%	65%
Flint Hills Resources, LP	7%	15%	9%

We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and gas we produce as other purchasers are available in our primary areas of activity. See "Additional Oil and Gas Disclosures—Marketing."

Employees

At December 31, 2017, we had 249 full-time employees. We believe that our relationships with our employees are satisfactory. We regularly use independent contractors and consultants to perform various field and other services.

Available Information

Our website can be accessed at www.carrizo.com. We make our website content available for informational purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Form 10-K. Within our website's investor relations section, we make available free of charge our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, including exhibits and amendments to these reports, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the SEC. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street NE, Washington, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. Reports filed with the SEC are also made available on its website at www.sec.gov.We also make available through our website information related to our corporate governance including the following:

- Audit Committee Charter;
- Compensation Committee Charter;
- Nominating and Corporate Governance Committee Charter;
- Code of Ethics and Business Conduct; and
- Compliance Employee Report Line.

We intend to satisfy the requirement under Item 5.05 of Form 8-K to disclose any amendments to our Code of Ethics and Business Conduct and any waiver from a provision of our Code of Ethics by posting such information on our website at www.carrizo.com under "About—Governance."

Glossary of Certain Industry Terms

The definitions set forth below shall apply to the indicated terms as used herein.

3-D seismic data. Three-dimensional pictures of the subsurface created by collecting and measuring the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to oil or other liquid hydrocarbons.

Bbls/d. Stock tank barrels per day.

Bcf. Billion cubic feet of natural gas.

Boe. Barrels of oil equivalent. A Boe is determined using the ratio of 6 Mcf of natural gas to one Bbl of oil or NGLs which approximates their relative energy content.

Boe/d. Barrels of oil equivalent per day.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Carried interest. An agreement under which one party (carrying party) agrees to pay for a specified portion or for all of the drilling and completion and operating costs of another party (carried party) on a property for a specified time in which both own a portion of the working interest. The carrying party may be able to recover a specified amount of costs from the carried party's share of the revenue from the production of reserves from the property.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil, NGLs or natural gas, or in the case of a dry well, the reporting of abandonment to the appropriate authority.

Condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Developed acreage. The number of acres allocated or assignable to productive wells or wells capable of production.

Developed oil and gas reserves. Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or for which the cost of the required equipment is relatively minor compared to the cost of a new well, and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. Development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill and equip development wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install, production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry well. An exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Economically producible. A resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of "oil and gas producing activities" as defined in Rule 4-10(a)(16) of Regulation S-X promulgated under the Securities Exchange Act of 1934, as amended.

Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition, or both. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Hydraulic fracturing. Hydraulic fracturing is a well stimulation process using a liquid (usually water with an amount of chemicals mixed in) that is forced into an underground formation under high pressure to open or enlarge fractures in reservoirs with low permeability to stimulate and improve the flow of hydrocarbons from these reservoirs. As the formation is fractured, a proppant (usually sand or ceramics) is pumped into the fractures to "prop" or keep them from closing after they are opened by the liquid. Hydraulic fracturing is a technology used in shale reservoirs and other unconventional resource plays in order to enable commercial hydrocarbon production.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

MBoe. Thousand barrels of oil equivalent.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Thousand cubic feet of natural gas per day.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, or condensate or one Boe of NGLs, which represents the approximate energy content of oil, condensate and NGLs as compared to natural gas. Despite holding this ratio constant at six Mcf to one Bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMBoe. Million barrels of oil equivalent.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/d. Million cubic feet of natural gas per day.

MMcfe. Million cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs, which represents the approximate energy content of oil, condensate and NGLs as compared to natural gas. Despite holding this ratio constant at six Mcf to one Bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

MMcfe/d. Million cubic feet of natural gas equivalent per day.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

Productive well. A well that is found to be capable of producing oil or gas in sufficient quantities to justify completion as an oil or gas well.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as:

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

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically, based on prices used to estimate reserves, through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped oil and gas reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility, based on pricing used to estimate reserves, at greater distances.

(ii) Undrilled locations are classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances are estimates for proved undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

PV-10 (Non-GAAP). The present value of estimated future revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, based on prices used in estimating the proved reserves and costs in effect as of the date indicated (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, or depreciation, depletion, and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period. This is a non-GAAP measure. See "Item 1. Business—Additional Oil and Gas Disclosures—Reconciliation of Standardized Measure of Discounted Future Net Cash Flows (GAAP) to PV-10 (Non-GAAP)"

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to EUR with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Reserves. Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil or gas, or both, that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Standardized measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the U.S. Securities Exchange Commission's rules for inclusion of oil and gas reserve information in financial statements filed with the U.S. Securities Exchange Commission.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Item 1A. Risk Factors

Oil and gas prices are highly volatile, and low oil and gas prices or further price decreases will negatively affect our financial position, planned capital expenditures and results of operations.

Our revenue, profitability, cash flow, future growth and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent on prevailing prices of oil and gas. Historically, the markets for oil and gas have been volatile, and those markets are likely to continue to be volatile in the future. Oil and gas commodity prices are affected by events beyond our control, including changes in market supply and demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. In the past, we have reduced or curtailed production to mitigate the impact of low oil and gas prices. Particularly in recent years, decreases in both oil and gas prices led us to suspend or curtail drilling and other exploration activities, which will limit our ability to produce oil and gas and therefore impact our revenues. Beginning the second half of 2014 and continuing into 2016, oil prices declined significantly. We are particularly dependent on the production and sale of oil and this commodity price decline has had, and may continue to have, an adverse effect on us. Further volatility in oil and gas prices or a continued prolonged period of low oil or gas prices may materially adversely affect our financial position, liquidity (including our borrowing capacity under our revolving credit facility), ability to finance planned capital expenditures and results of operations.

It is impossible to predict future oil and gas price movements with certainty. Prices for oil and gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include, but are not limited to:

- the level of consumer product demand;
- the levels and location of oil and gas supply and demand and expectations regarding supply and demand, including the supply of oil and natural gas due to increased production from resource plays;
- overall economic conditions;
- weather conditions;
- domestic and foreign governmental relations, regulations and taxes;
- the price and availability of alternative fuels;
- political conditions or hostilities and unrest in oil producing regions;
- the level and price of foreign imports of oil and liquefied natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree upon and maintain production constraints and oil price controls;
- the extent to which U.S. shale producers become "swing producers" adding or subtracting to the world supply;
- technological advances affecting energy consumption;
- speculation by investors in oil and gas; and
- variations between product prices at sales points and applicable index prices.

The profitability of wells, particularly in the shale plays in which we primarily operate, is generally reduced or eliminated as commodity prices decline. In addition, certain wells that are profitable may not meet our internal return targets. Based on our current estimates of drilling and completion costs, ultimate recoveries per well, differentials and operating costs, we believe a portion of our acreage if drilled would not be economical at commodity prices existing in 2017 and most would not be economical at the commodity price lows seen in early 2016. There can be no assurance, however, that any wells, including wells drilled on our Eagle Ford and Delaware Basin acreage, will actually be profitable at any estimated prices. The sustained declines in commodity prices have caused us to significantly reduce our exploration and development activity which may adversely affect our results of operations, cash flows and our business.

Oil and gas drilling is a speculative activity and involves numerous risks and substantial and uncertain costs that could adversely affect us.

Our success will be largely dependent upon the success of our drilling program. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments.

Drilling for oil and gas involves numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including:

- unexpected or adverse drilling conditions;
- elevated pressure or irregularities in geologic formations;
- equipment failures or accidents;
- adverse weather conditions;
- fluctuations in the price of oil and gas;
- surface access restrictions;
- loss of title or other title related issues;
- compliance with governmental requirements; and
- shortages or delays in the availability of midstream transportation, drilling rigs, crews and equipment.

Because we identify the areas desirable for drilling in certain areas from 3-D seismic data covering large areas, we may not seek to acquire an option or lease rights until after the seismic data is analyzed or until the drilling locations are also identified; in those cases, we may not be permitted to lease, drill or produce oil or gas from those locations.

Even if drilled, our completed wells may not produce reserves of oil or gas that are economically viable or that meet our earlier estimates of economically recoverable reserves. Our overall drilling success rate or our drilling success rate for activity within a particular project area may decline. Unsuccessful drilling activities could result in a significant decline in our production and revenues and materially harm our operations and financial position by reducing our available cash and resources. The potential for production decline rates for our wells could be greater than we expect. Because of the risks and uncertainties of our business, our future performance in exploration and drilling may not be comparable to our historical performance described herein.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any wells will be dependent on a number of factors, including:

- the results of our exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability and cost of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by the other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling or completion, including prevailing and anticipated prices for oil and gas and the availability and prices of drilling rigs, drilling and hydraulic fracturing crews and equipment, other services, supplies and equipment, and pipeline system and transportation constraints;
- lease expirations;
- access to water supplies or restrictions on water disposal;
- regulatory approvals; and
- the availability of leases and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. Wells that are currently part of our capital plan may be based on statistical results of drilling activities in other 3-D project areas that we believe are geologically similar rather than on analysis of seismic or other data in the prospect area, in which case actual drilling and results are likely to vary, possibly materially, from those statistical results. In addition, our drilling schedule may vary from our expectations because of future uncertainties. We may not be able to raise the capital required to drill all of our identified or budgeted wells. In addition, our ability to produce oil and gas may be significantly affected by the availability and prices of hydraulic fracturing equipment and crews. There can be no assurance that these projects can be successfully developed or that any identified drill sites or budgeted wells will, if drilled, encounter reservoirs of commercially productive oil or gas. We may seek to sell or reduce all or a portion of our interest in a project area or with respect to prospects or budgeted wells within such project area.

Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future.

There are uncertainties inherent in estimating oil and gas reserves and their estimated value, including many factors beyond the control of the producer. The reserve data included herein represents only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner and is based on assumptions that may vary considerably from actual results. These include subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may be incorrect. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Reserve estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Additionally, in recent years, there has been increased debate and disagreement over the classification of reserves, with particular focus on proved undeveloped reserves. The interpretation of SEC rules regarding the classification of reserves and their applicability in different situations remain unclear in many respects. Changing interpretations of the classification standards of reserves or disagreements with our interpretations could cause us to write down reserves.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement may limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe. We have deferred some of our exploration activities in response to the severe price downturn beginning in the summer of 2014 and such continued deferral may increase the impact of this requirement.

As of December 31, 2017, approximately 58% of our proved reserves were proved undeveloped. Moreover, some of the producing wells included in our reserve reports as of December 31, 2017 had produced for a relatively short period of time as of that date. Because most of our reserve estimates are calculated using volumetric analysis, those estimates are less reliable than estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure based on seismic analysis. In addition, realization or recognition of our proved undeveloped reserves will depend on our development schedule and plans. Lack of reasonable certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

The discounted future net cash flows included herein are not necessarily the same as the current market value of our estimated oil and gas reserves. As required by the current requirements for oil and gas reserve estimation and disclosures, the estimated discounted future net cash flows from proved reserves are based on the average of the sales price on the first day of each month during the trailing 12-month period prior to December 31, 2017, with costs determined as of the date of the estimate. If commodity prices remain at their current levels, the estimated discounted future net cash flows from our proved reserves would generally be expected to increase as earlier months with lower commodity sales prices will be removed from this calculation in the future.

Actual future net cash flows also will be affected by factors such as:

- the actual prices we receive for oil and gas;
- our actual operating costs in producing oil and gas;
- the amount and timing of actual production;
- supply and demand for oil and gas;
- increases or decreases in consumption of oil and gas; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board Accounting Standards Codification Topic 932, "Extractive Activities-Oil and Gas" may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future.

In general, the volume of production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we conduct successful exploration and development activities or acquire properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Our future oil and gas production is, therefore, highly dependent on our level of success in developing, finding or acquiring additional reserves that are economically recoverable. There can be no assurance that undeveloped properties acquired by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such undeveloped properties or wells.

Our future acquisitions may yield revenues or production that varies significantly from our projections.

In acquiring producing properties, we assess the recoverable reserves, current and future oil and gas prices, development and operating costs, potential environmental and other liabilities and other factors relating to the properties. Our assessments are necessarily inexact and their accuracy is inherently uncertain. Our review of a subject property in connection with our acquisition assessment will not reveal all existing or potential problems or permit us to become sufficiently familiar with the property to assess fully its deficiencies and capabilities. We may not inspect every well, and we may not be able to observe structural and environmental problems even when we do inspect a well. If problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of those problems and we may be forced to assume liabilities that we did not accurately quantify. We may increase our emphasis on producing property acquisitions. We have relatively less experience in such acquisitions as our past acquisition focus has been primarily on nonproducing acreage. Any acquisition of property interests may not be economically successful, and unsuccessful acquisitions may have a material adverse effect on our financial position and future results of operations.

We may not be able to achieve the expected benefits of the ExL Acquisition and may have difficulty integrating the ExL Properties.

There can be no assurance that the ExL Acquisition will be beneficial to us. We may not be able to integrate and develop the ExL Properties without increases in costs, losses in revenues or other difficulties. Any unexpected costs or delays incurred in connection with the integration and development of the ExL Properties could have an adverse effect on our business, results of operations, financial condition and prospects, as well as the market price of our common stock.

The market price of our common stock may decline as a result of the ExL Acquisition if, among other things, the integration and development of the ExL Properties is unsuccessful or if the liabilities, expenses, title, environmental and other defects, or transaction costs related to the ExL Acquisition are greater than expected or the ExL Properties do not yield the anticipated returns. The market price of our common stock may decline if we do not achieve the perceived benefits of the ExL Acquisition as rapidly or to the extent anticipated by us or by securities market participants or if the effect of the ExL Acquisition, including the obligations incurred to finance the ExL Acquisition, on our business results of operations or financial condition or prospects is not consistent with our expectations or those of securities market participants.

Upon consummation of the ExL Acquisition, our overall level of debt and Preferred Stock obligations increased, which could adversely affect us.

Upon consummation of the ExL Acquisition, our overall debt level increased after giving effect to the ExL Acquisition and our senior notes offering. In connection with the ExL Acquisition, we issued Preferred Stock with an aggregate initial liquidation preference of $250.0 million (subsequently reduced to $200.0 million) that requires us, upon request of holders of a majority of the then-outstanding shares of Preferred Stock, to redeem the Preferred Stock, in whole or in part, on or after the seventh anniversary of its issuance and upon certain defaults and changes of control. Our increased level of debt and other obligations could have significant adverse consequences on our business and future prospects, including the following:

- we may not be able to obtain financing in the future on acceptable terms or at all for working capital, capital expenditures, acquisitions, debt service requirements or other purposes;
- less-levered competitors could have a competitive advantage because they have lower debt service requirements;
- credit rating agencies could downgrade our credit ratings following the ExL Acquisition below currently expected levels; and
- we may be less able to take advantage of significant business opportunities and to react to changes in market or industry conditions than our competitors.

A future issuance, sale or exchange of our stock or warrants could trigger a limitation on our ability to utilize net operating loss carryforwards.

Our ability to utilize U.S. net operating loss carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended (the "Code"). The utilization of such carryforwards may be limited under Section 382 of the Code upon the occurrence of ownership changes resulting from issuances of our stock or the sale or exchange of our stock by certain shareholders if, as a result, there is an aggregate change of more than 50% in the beneficial ownership of our stock during any three-year period. For this purpose, "stock" includes certain preferred stock and warrants (including the Preferred Stock and the Warrants issued to finance in part, the ExL Acquisition). In the event of such an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our taxable income that can be offset by these loss carryforwards. The limitation is generally equal to the product of (a) the fair market value of our equity multiplied by (b) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains inherent in the assets sold. We do not believe we have a Section 382 limitation on the ability to utilize our U.S. loss carryforwards as of December 31, 2017. However, future issuances, sales or exchanges of our stock (including, potentially, relatively small transactions and transactions beyond our control) could, taken together with prior transactions with respect to our stock, trigger an ownership change under Section 382 of the Code and therefore a limitation on our ability to utilize our U.S. loss carryforwards. Any such limitation could cause some of such loss carryforwards to expire before we would be able to utilize them to reduce taxable income in future periods, possibly resulting in a substantial income tax expense or write down of our tax assets or both.

Holders of the Preferred Stock have rights that may restrict our ability to operate our business or be adverse to holders of our common stock.

The Statement of Resolutions Establishing Series of 8.875% Redeemable Preferred Stock of Carrizo Oil & Gas, Inc. (the "Statement of Resolutions") contains covenants that, among other things, so long as the GSO Funds (as defined below) and their affiliates beneficially own more than 50% of the outstanding Preferred Stock, limit our ability to, without the written consent of a designated representative of the Preferred Stock, but subject to certain exceptions, (i) issue stock senior to or on parity with the Preferred Stock, (ii) incur indebtedness that would cause us to exceed a specified leverage ratio, (iii) amend, modify, alter or supplement our articles of incorporation or the Statement of Resolutions in a manner that would adversely affect the rights, preferences or privileges of the Preferred Stock, (iv) enter into or amend certain debt agreements that would be more restrictive on the payment of dividends on, or redemption of, the Preferred Stock than those existing on the Preferred Stock closing and (v) pay distributions on, purchase or redeem our common stock or other stock junior to the Preferred Stock that would cause us to exceed a specified leverage ratio. We can be required to redeem the Preferred Stock (i) after the seventh anniversary of its initial issuance or (ii) at any time we fail to pay a dividend, subject to limited cure rights.

Holders of the Preferred Stock will, in certain circumstances, have additional rights in the event we fail to timely pay dividends, fail to redeem the Preferred Stock upon a change of control if required or fail to redeem the Preferred Stock upon request of the holders of the Preferred Stock following the seventh anniversary of the date of issuing the Preferred Stock. These rights include, subject to certain exceptions, (i) that holders of a majority of the then-outstanding Preferred Stock will have the exclusive right, voting separately as a class, to appoint and elect up to two directors to our board of directors, (ii) that approval of the holders of a majority of the then-outstanding Preferred Stock will be required prior to incurring indebtedness subject to a leverage ratio, declaring or paying prohibited distributions or issuing equity of subsidiaries to third parties; and (iii) that holders of a majority of the then-outstanding Preferred Stock will have the right to increase dividend payments and the ability to require us to pay dividends in common stock.

Holders of the Preferred Stock also have limited voting rights, including those with respect to potential amendments to our articles of incorporation or the Statement of Resolutions that have an adverse effect on the existing terms of the Preferred Stock and in certain other limited circumstances or as required by law.

We participate in oil and gas leases with third parties and these third parties may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of the other working interest owners such as nonpayment of costs and liabilities arising from the actions of the other working interest owners. Some of these working interest owners may experience liquidity and cash flow problems. These problems may lead these parties to attempt to delay the pace of drilling or project development in order to preserve cash. A working interest owner may be unable or unwilling to pay its share of project costs. In some cases, a working interest owner may declare bankruptcy. In the event any of these third party working interest owners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from such parties, which could materially adversely affect our financial position.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage or we timely exercise our contractual rights to extend the terms of such leases by continuous operations or the payment of lease extension payments or delay rentals.

Leases on oil and natural gas properties typically have a primary term of three to five years, after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established, applicable lease extension payments or delay rentals are made, or such lease is otherwise maintained pursuant to any applicable continuous operations provision. If our leases on our undeveloped properties expire and we are unable to renew the leases, we will lose our right to develop the related properties. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. If commodity prices remain low, we may be required to delay our drilling plans and, as a result, may lose our right to develop the related properties.

We have substantial capital requirements that, if not met, may hinder operations.

We have experienced and expect to continue to experience substantial capital needs as a result of our active exploration and development program and acquisitions. We expect that additional external financing will be required in the future to fund our growth. We may not be able to obtain additional financing, and financing under our existing revolving credit facility or new credit facilities may not be available in the future. Even if additional capital becomes available, it may not be on terms acceptable to us. As in the past, without additional capital resources, we may be forced to limit or defer our planned oil and gas exploration and development drilling program by releasing rigs or deferring fracturing, completion and hookup of the wells to pipelines and thereby adversely affect our production, cash flow, and the recoverability and ultimate value of our oil and gas properties, in turn negatively affecting our business, financial position and results of operations.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases. Our ability to sell oil and natural gas and receive market prices for our oil and natural gas may be adversely affected by pipeline and gathering system capacity constraints.

Market conditions or the unavailability of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. However, such trucking and compression facilities may not always be available to us in acceptable terms or at all. Such restrictions on our ability to sell our oil or gas may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production. Pipeline and gathering constraints have in the past required, and may in the future require, us to flare natural gas occasionally, decreasing the volumes sold from our wells. Our lease terms may require us to pay royalties on such flared gas to maintain our leases, which could adversely affect our business. There is currently limited pipeline and gathering system capacity in areas where we operate. See "-Interruption to crude oil and natural gas gathering systems, pipelines and transportation and processing facilities we do not own could result in the loss of production and revenues."

Historically, when available we have generally delivered our oil and gas production through gathering systems and pipelines that we do not own under interruptible or short-term transportation agreements. Under the interruptible transportation agreements, the transportation of our oil and gas production may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. In the Delaware Basin, we have entered into firm transportation agreements for a portion of our production in such areas in order to assure our ability, and that of our purchasers, to successfully market the oil and gas that we produce. We may also enter into firm transportation arrangements for additional production in the future. These firm transportation agreements may be more costly than interruptible or short-term transportation agreements.

A portion of our oil and gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss or unavailability of pipeline or gathering system access and capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions, including low oil and gas prices. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow. Furthermore, if we were required to shut in wells we might also be obligated to pay shut-in royalties to certain mineral interest owners in order to maintain our leases.

Interruption to crude oil and natural gas gathering systems, pipelines and transportation and processing facilities we do not own could result in the loss of production and revenues.

Our operations are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and transportation and processing facilities we do not own. Any significant change affecting these infrastructure facilities could materially harm our business. The lack of available capacity of gathering systems, pipelines and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. These systems and facilities may be temporarily unavailable due to adverse weather conditions or operational issues or may not be available to us in the future. See "-Our operations are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues." Additionally, activists or other efforts may delay or halt the construction of additional pipelines or facilities. To the extent these services are unavailable, we would be unable to realize revenue from wells served by such systems and facilities until suitable arrangements are made to market our production. As a result, we could experience reductions in revenue that could reduce or eliminate the funds available for our exploration and development programs and acquisitions, or result in the loss of property.

Instability in the global financial system or in the oil and gas industry sector may have impacts on our liquidity and financial condition that we currently cannot predict.

Instability in the global financial system or in the oil and gas industry sector may have a material impact on our liquidity and our financial condition. We rely upon access to both our revolving credit facility and longer-term capital markets as sources of liquidity for any capital requirements not satisfied by the cash flow from operations or other sources. Our ability to access the capital markets or borrow money may be restricted or made more expensive at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions and on our ability to fund our operations and capital expenditures in the future. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions, including with respect to commodity prices such as for oil and gas, could have an impact on our oil and gas derivative instruments if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, challenges in the economy have led and could further lead to reductions in the demand for oil and gas, or further reductions in the prices of oil and gas, or both, which could have a negative impact on our financial position, results of operations and cash flows.

The risks associated with our debt and the provisions of our debt agreements could adversely affect our business, financial position and results of operations.

We have demands on our cash resources, including interest expense, operating expenses and funding of our capital expenditures. Our level of long-term debt, the demands on our cash resources and the provisions of the credit agreement governing our revolving credit facility and the indentures governing our 7.50% Senior Notes, our 6.25% Senior Notes due 2023 (the "6.25% Senior Notes") and our 8.25% Senior Notes may have adverse consequences on our operations and financial results, including:

- placing us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financial flexibility than we do;
- limiting our financial flexibility, including our ability to borrow additional funds, pay dividends, make certain investments and issue equity on favorable terms or at all;
- limiting our flexibility in planning for, and reacting to, changes in business conditions;
- increasing our interest expense on our variable rate borrowings if interest rates increase;
- requiring us to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;
- requiring us to modify our operations, including by curtailing portions of our drilling program, selling assets, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing, which may be on unfavorable terms; and
- making us more vulnerable to downturns in our business or the economy, including a decline in oil prices.

In addition, the provisions of our revolving credit facility and our 7.50% Senior Notes, our 6.25% Senior Notes and our 8.25% Senior Notes place restrictions on us and certain of our subsidiaries with respect to incurring additional indebtedness and liens, making dividends and other payments to shareholders, repurchasing our common stock, repurchasing or redeeming our 7.50% Senior Notes, our 6.25% Senior Notes and our 8.25% Senior Notes, making investments, acquisitions, mergers and asset dispositions, entering into hedging transactions and other matters. Our revolving credit facility also requires compliance with covenants to maintain specified financial ratios. Our business plan and our compliance with these covenants are based on a number of assumptions, the most important of which is relatively stable oil and gas prices at economically sustainable levels. If the prices that we receive for our oil and gas production continue to remain at low levels or to decline, it could lead to further reduced revenues, cash flow and earnings, which in turn could lead to a default under certain financial covenants contained in our revolving credit facility, including the covenants related to working capital and the ratios described above. Also, a further decline in or sustained low oil and gas prices could result in a lowering of our credit ratings by rating agencies, which could adversely impact the pricing of, or our ability to issue, new debt instruments. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period as the amounts outstanding under our revolving credit facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings. If a further decline in oil or gas prices were to occur in the future or if low prices continue for an extended period, it could further increase the risk of a lowering in our credit rating or our inability to comply with covenants to maintain specified financial ratios. Additionally, these ratios may have the effect of restricting us from borrowing the full amount available under the borrowing base for our revolving credit facility. In order to provide a margin of comfort with regard to these financial covenants, we may seek to further reduce our capital expenditure plan, sell additional non-strategic assets or opportunistically modify or increase our derivative instruments to the extent permitted under our revolving credit facility. We cannot assure you that we will be able to successfully execute any of these strategies, or if executed, that they will be sufficient to avoid a default under our revolving credit facility if a further decline in oil or gas prices were to occur in the future or if low prices continue for an extended period.

The terms of our Preferred Stock have many of the same effects as our debt and terms of our debt agreements. See "—Upon consummation of the ExL Acquisition, our overall level of debt and Preferred Stock obligations increased, which could adversely affect us." and "—Holders of the Preferred Stock have rights that may restrict our ability to operate our business or be adverse to holders of our common stock."

The borrowing base under our revolving credit facility may be reduced below the amount of borrowings outstanding under such facility.

Under the terms of our revolving credit facility, our borrowing base is subject to redeterminations at least semi-annually based in part on assumptions of the administrative agent with respect to, among other things, crude oil and natural gas prices. A negative adjustment could occur if the crude oil and natural gas prices used by the banks in calculating the borrowing base are significantly lower than those used in the last redetermination, including as a result of a decline in crude oil prices or an expectation that such reduced prices will continue. The next redetermination of our borrowing base is scheduled to occur in Spring 2018. In addition, the portion of our borrowing base made available to us is subject to the terms and covenants of our revolving credit facility, including compliance with the ratios and other financial covenants of such facility. In the event the amount outstanding under our revolving credit facility exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings. We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell a portion of our assets.

We may face difficulties in securing and operating under authorizations and permits to drill, complete or operate our wells.

The recent growth in oil and gas exploration in the United States has drawn intense scrutiny from environmental and community interest groups, regulatory agencies and other governmental entities. As a result, we may face significant opposition to, or increased regulation of, our operations that may make it difficult or impossible to obtain permits and other needed authorizations to drill, complete or operate, result in operational delays, or otherwise make oil and gas exploration more costly or difficult than in other countries.

We have only limited experience drilling wells in the Delaware Basin and less information regarding reserves and decline rates in these shale formations than in some other areas of our operations.

We have limited exploration and development experience in the Delaware Basin. We have participated in the drilling of only 40 gross (20.3 net) wells in the Delaware Basin. Other operators in these areas have significantly more experience in the drilling of wells, including the drilling of horizontal wells. As a result, we have less information with respect to the ultimate recoverable reserves, the production decline rate and other matters relating to the exploration, drilling and development of the Delaware Basin than we have in our Eagle Ford area in which we operate.

If we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules, our ability to produce oil and gas commercially and in commercial quantities could be impaired.

We use a substantial amount of water in our drilling operations. Our inability to locate sufficient amounts of water, or to treat and dispose of water after drilling at a reasonable cost, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas. Furthermore, future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells could increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance. For example, in June 2016, the EPA established pretreatment standards for disposal of wastewater produced from unconventional oil and natural gas extraction facilities into publicly owned treatment works. In response to these actions, operators including us have begun to rely more on recycling of flowback and produced water from well sites as a preferred alternative to disposal.

We may not increase our acreage positions in areas with exposure to oil, condensate and NGLs.

If we are unable to increase our acreage positions in the Eagle Ford and Delaware Basin, this may detract from our efforts to realize our growth strategy in crude oil plays. Additionally, we may be unable to find or consummate other opportunities in these areas or in other areas with similar exposure to oil, condensate and NGLs on similar terms or at all.

Restricted land access could reduce our ability to explore for and develop oil and gas reserves.

Our ability to adequately explore for and develop oil and gas resources is affected by a number of factors related to access to land. Examples of factors which reduce our access to land include, among others:

- new municipal or state land use regulations, which may restrict drilling locations or certain activities such as hydraulic fracturing;
- local and municipal government control of land or zoning requirements, which can conflict with state law and deprive land owners of property development rights;
- landowner or foreign governments' opposition to infrastructure development;
- regulation of federal land by the U.S. Department of the Interior Bureau of Land Management or other federal government agencies;
- anti-development activities, which can reduce our access to leases through legal challenges or lawsuits, disruption of drilling, or damage to equipment;
- disputes regarding leases; and
- disputes with landowners, royalty owners, or other operators over such matters as title transfer, joint interest billing arrangements, revenue distribution, or production or cost sharing arrangements.

Loss of access to land for which we own mineral rights could result in a reduction in our proved reserves and a negative impact on our results of operations and cash flows. Reduced ability to obtain new leases could constrain our future growth and opportunity set by limiting the expansion of our operations.

We face strong competition from other oil and gas companies.

We encounter competition from other oil and gas companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies that have been engaged in the oil and gas business much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. These companies may be able to pay more for exploratory projects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry. Such competitors may also be in a better position to secure oilfield services and equipment on a timely basis or on favorable terms. These companies may also have a greater ability to continue drilling activities during periods of low oil and gas prices, such as the current commodity price environment, and to absorb the burden of current and future governmental regulations and taxation. We may not be able to conduct our operations, evaluate and select suitable properties and consummate transactions successfully in this highly competitive environment.

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Part of our strategy involves drilling existing or emerging shale plays using some of the latest available seismic, horizontal drilling and completion techniques. The results of our planned exploratory and delineation drilling in these plays are subject to drilling and completion technique risks, and drilling results may not meet our expectations for reserves or production. As a result, the value of our undeveloped acreage could decline if drilling results are unsuccessful.

We rely to a significant extent on seismic data and other advanced technologies in evaluating undeveloped properties and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to drilling and completing a well, whether oil or natural gas is present or may be produced economically.

Many of our operations involve drilling and completion techniques developed by us or our service providers in order to maximize cumulative recoveries. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore, and being able to run tools and recover equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools and other equipment the entire length of the well bore during completion operations, being able to recover such tools and other equipment, and successfully cleaning out the well bore after completion of the final fracture stimulation.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, limited access to gathering systems and takeaway capacity, commodity price decline, or other reasons, then the return on our investment for a particular project may not be as attractive as we anticipated and the value of our undeveloped acreage could decline in the future.

We are subject to various environmental risks and governmental regulations, including those relating to benzene emissions, hydraulic fracturing and global climate change, and future regulations may be more stringent resulting in increased operating costs and decreased demand for the oil and gas that we produce.

Oil and gas operations are subject to various federal, state, local and foreign laws and government regulations that may change from time to time. Matters subject to regulation include discharge permits for drilling operations, well testing, plug and abandonment requirements and bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas. Other federal, state, local and foreign laws and regulations relating primarily to the protection of human health and the environment apply to the development, production, handling, storage, transportation and disposal of oil and gas, by-products thereof and other substances and materials produced or used in connection with oil and gas operations, including drilling fluids and wastewater. We may incur costs arising out of property damage, including environmental damage caused by previous owners or operators of property we purchase or lease or relating to third party sites, or injuries to employees and other persons. As a result, we may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted. Compliance with existing, new or modified laws and regulations could result in substantial costs, delay our operations or otherwise have a material adverse effect on our business, financial position and results of operations.

Moreover, changes in environmental laws and regulations occur frequently and such laws and regulations tend to become more stringent over time. Increased scrutiny of our industry may also occur as a result of the EPA's 2017-2019 National Enforcement Initiative, "Ensuring Energy Extraction Activities Comply with Environmental Laws," through which the EPA will address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health or the environment. Stricter laws, regulations or enforcement policies could significantly increase our compliance costs and negatively impact our production and operations, which could have a material adverse effect on our results of operations and cash flows. See "Item 1. Business-Additional Oil and Gas Disclosures-Regulation-Environmental Regulations" for additional information.

There is increasing attention in the United States and worldwide to the issue of climate change and the contributing effect of GHG emissions. The modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs. See "Item 1. Business-Additional Oil and Gas Disclosures-Regulation-Global Climate Change" for additional information.

Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional resource plays. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and gas production. The U.S. Congress has considered legislation to subject hydraulic fracturing operations to federal regulation and to require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. The EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel under the federal Safe Drinking Water Act and has released permitting guidance for hydraulic fracturing operations that use diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. In addition, in March 2015, the BLM issued a final rule to regulate hydraulic fracturing on federal and Indian land. However, in December 2017, the BLM published a final rule rescinding the 2015 rule. Further, the EPA issued an Advanced Notice of Proposed Rulemaking in May 2014 seeking comments relating to the information that should be reported or disclosed for hydraulic fracturing chemical substances and mixtures and mechanisms for obtaining this information. A number of federal agencies are also analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, in December 2016, the EPA released the final results of a study of the potential impacts of hydraulic fracturing activities on drinking water resources in the states where the EPA is the permitted authority. The study concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. These ongoing or proposed studies, depending on their course and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other regulatory mechanisms.

State and federal regulatory agencies recently have focused on a possible connection between hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. Some state regulatory agencies, including those in Texas, have modified their regulations to account for induced seismicity. Regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity; and a 2015 report by researchers at the University of Texas has suggested that the link between seismic activity and wastewater disposal may vary by region. In March 2016, the United States Geological Survey (the "USGS") identified states with the most significant hazards from induced seismicity, which included Texas. A 2017 study conducted by the USGS similarly identified a high seismic hazard for areas of several states, including north Texas. A number of lawsuits have been filed alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells and hydraulic fracturing. Such regulations and restrictions could cause delays and impose additional costs and restrictions on our operations and on our and our contractors' waste disposal activities.

Several states, including states where we operate such as Texas, have proposed or adopted legislative or regulatory restrictions on hydraulic fracturing through additional permit requirements, public disclosure of fracturing fluid contents, water sampling requirements, and operational restrictions. Further, some states and local governments have adopted or are considering adopting bans on drilling. For example, the City of Denton, Texas adopted a moratorium on hydraulic fracturing in November 2014, which was later lifted in 2015. We use hydraulic fracturing extensively and any increased federal, state, local, foreign or international regulation of hydraulic fracturing or offshore drilling, including legislation and regulation in the state of Texas, could reduce the volumes of oil and gas that we can economically recover, which could materially and adversely affect our revenues and results of operations. See "Item 1. Business-Additional Oil and Gas Disclosures-Regulation-Regulation of Natural Gas and Oil Exploration and Production" and "-Environmental Regulations" for additional information.

From time to time legislation is introduced in the U.S. Congress that, if enacted into law, would make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial position and results of operations.

We face various risks associated with the trend toward increased anti-development activity.

As new technologies have been applied to our industry, we have seen significant growth in oil and gas supply in recent years, particularly in the U.S. With this expansion of oil and gas development activity, opposition toward oil and gas drilling and development activity has been growing both in the U.S. and globally. Companies in the oil and gas industry, such as us, can be the target of opposition to development from certain stakeholder groups. These anti-development efforts could be focused on:

- limiting oil and gas development;
- reducing access to federal and state owned lands;
- delaying or canceling certain projects such as shale development and pipeline construction;

- limiting or banning the use of hydraulic fracturing;
- denying air-quality permits for drilling; and
- advocating for increased regulations on shale drilling and hydraulic fracturing.

Future anti-development efforts could result in the following:

- blocked development;
- denial or delay of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- reduced access to water supplies or restrictions on water disposal;
- limited access or damage to or destruction of our property;
- legal challenges or lawsuits;
- increased regulation of our business;
- damaging publicity and reputational harm;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Our need to incur costs associated with responding to these initiatives or complying with any new legal or regulatory requirements resulting from these activities that are substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations. In addition, the use of social media channels can be used to cause rapid, widespread reputational harm.

Our operations are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues.

The oil and gas business involves operating hazards such as:

- well blowouts;
- mechanical failures;
- explosions;
- pipe or cement failures and casing collapses, which could release oil, natural gas, drilling fluids or hydraulic fracturing fluids;
- uncontrollable flows of oil, natural gas or well fluids;
- fires;
- geologic formations with abnormal pressures;
- spillage handling and disposing of materials, including drilling fluids and hydraulic fracturing fluids and other pollutants;
- pipeline ruptures or spills;
- releases of toxic gases;
- adverse weather conditions, including drought, flooding, winter storms, snow, hurricanes or other severe weather events; and
- other environmental hazards and risks including conditions caused by previous owners and lessors of our properties.

Any of these hazards and risks can result in substantial losses to us from, among other things, injury or loss or life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties and suspension of operations. As a result we could incur substantial liabilities or experience reductions in revenue that could reduce or eliminate the funds available for our exploration and development programs and acquisitions.

We may not have enough insurance to cover all of the risks we face.

We maintain insurance against losses and liabilities in accordance with customary industry practices and in amounts that management believes to be prudent; however, insurance against all operational risks is not available to us. We do not carry business interruption insurance. We may elect not to carry insurance if management believes that the cost of available insurance is excessive relative to the risks presented. In addition, losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. We cannot insure fully against pollution and environmental risks. We cannot assure you that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

We conduct a portion of our operations through a joint venture, which subjects us to additional risks that could have a material adverse effect on the success of these operations, our financial position and our results of operations.

We conduct a portion of our operations through a joint venture with GAIL. We may also enter into other joint venture arrangements in the future. These third parties may have obligations that are important to the success of the joint venture, such as the obligation to pay carried costs pertaining to the joint venture and to pay their share of capital and other costs of the joint venture. The performance of these third party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside our control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

Our joint venture arrangements may involve risks not otherwise present when exploring and developing properties directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;
- our joint venture partners may not pay their share of the joint venture's obligations, leaving us liable for their shares of joint venture liabilities;
- we may incur liabilities as a result of an action taken by our joint venture partners;
- we may be required to devote significant management time to the requirements of and matters relating to the joint ventures;
- our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue our joint ventures or to resolve disagreements with our joint venture partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn negatively affect our financial condition and results of operations. The risks described above or the failure to continue our joint ventures or to resolve disagreements with our joint venture partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn negatively affect our financial condition and results of operations. The agreements under which we formed certain joint ventures may subject us to various risks, limit the actions we may take with respect to the properties subject to the joint venture and require us to grant rights to our joint venture partners that could limit our ability to benefit fully from future positive developments. Some joint ventures require us to make significant capital expenditures. If we do not timely meet our financial commitments or otherwise do not comply with our joint venture agreements, our rights to participate, exercise operator rights or otherwise influence or benefit from the joint venture may be adversely affected. Certain of our joint venture partners may have greater financial resources than we have and we may not be able to secure the funding necessary to participate in operations our joint venture partners propose, thereby reducing our ability to benefit from the joint venture.

We cannot control the activities on properties we do not operate.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interests could reduce our production and revenues or could create liability for us for the operator's failure to properly maintain the well and facilities and to adhere to applicable safety and environmental standards. With respect to properties that we do not operate:

- the operator could refuse to initiate exploration or development projects;

- if we proceed with any of those projects the operator has refused to initiate, we may not receive any funding from the operator with respect to that project;
- the operator may initiate exploration or development projects on a different schedule than we would prefer;
- the operator may propose greater capital expenditures than we wish, including expenditures to drill more wells or build more facilities on a project than we have funds for, which may mean that we cannot participate in those projects or participate in a substantial amount of the revenues from those projects; and
- the operator may not have sufficient expertise or resources.

Any of these events could significantly and adversely affect our anticipated exploration and development activities.

Our business may suffer if we lose key personnel.

We depend to a large extent on the services of certain key management personnel, including our executive officers and other key employees, the loss of any of whom could have a material adverse effect on our operations. We have entered into employment agreements with many of our key employees as a way to assist in retaining their services and motivating their performance. We do not maintain key-man life insurance with respect to any of our employees. Our success will also be dependent on our ability to continue to employ and retain skilled technical personnel.

We may experience difficulty in achieving and managing future growth.

We have experienced growth in the past primarily through the expansion of our drilling program. Future growth may place strains on our financial, technical, operational and administrative resources and cause us to rely more on project partners and independent contractors, possibly negatively affecting our financial position and results of operations. Our ability to grow will depend on a number of factors, including:

- our ability to obtain leases or options on properties, including those for which we have 3-D seismic data;
- our ability to acquire additional 3-D seismic data;
- our ability to identify and acquire new exploratory prospects;
- our ability to develop existing prospects;
- our ability to continue to retain and attract skilled personnel;
- our ability to maintain or enter into new relationships with project partners and independent contractors;
- the results of our drilling program;
- hydrocarbon prices; and
- our access to capital.

We may not be successful in upgrading our technical, operations and administrative resources or in increasing our ability to internally provide certain of the services currently provided by outside sources, and we may not be able to maintain or enter into new relationships with project partners and independent contractors. Our inability to achieve or manage growth may adversely affect our financial position and results of operations.

We may continue to enter into or exercise commodity derivative transactions to manage the price risks associated with our production, which may expose us to risk of financial loss and limit the benefit to us of increases in prices for oil and gas.

Because oil and gas prices are unstable, we periodically enter into price-risk-management transactions such as fixed-rate swaps, costless collars, three-way collars, puts, calls and basis differential swaps to reduce our exposure to price declines associated with a portion of our oil and gas production and thereby to achieve a more predictable cash flow. Additionally, in our ExL Acquisition, we entered into arrangements whereby we will be required to make additional payments if oil prices exceed specified levels for certain periods of time. We have also entered into arrangements in some of our disposition transactions where we similarly receive such payments. The use of these arrangements limits our ability to benefit from increases in the prices of oil and gas. Additionally, some derivative transactions may help to assure favorable pricing in the near term, but at the cost of limiting our ability to benefit from price increases that occur in subsequent years. At any given time our derivative arrangements may apply to only a portion of our production, including following the exercise of any then-existing derivative instruments, thereby providing only partial protection against declines in oil and gas prices. These arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which production is less than expected, our customers fail to purchase contracted quantities of oil and gas or a sudden, unexpected event materially impacts oil or gas prices. In addition, the counterparties under our derivatives contracts may fail to fulfill their contractual obligations to us or there may be an adverse change in the expected differential between the underlying price in the derivative instrument and the actual prices received for our production. During periods of declining commodity prices, our commodity price derivative positions increase, which increases our counterparty exposure.

As our derivatives expire, more of our future production will be sold at market prices unless we enter into additional derivative transactions. If we are unable to enter into new derivative contracts in the future at favorable pricing and for a sufficient amount of our production, our financial condition and results of operations could be materially adversely affected. It is also possible that a larger percentage of our future production will not be hedged as our derivative policies may change, which would result in our oil and gas revenue becoming more sensitive to commodity price changes.

The CFTC has promulgated regulations to implement statutory requirements for swap transactions. These regulations are intended to implement a regulated market in which most swaps are executed on registered exchanges or swap execution facilities and cleared through central counterparties. While we believe that our use of swap transactions exempt us from certain regulatory requirements, the changes to the swap market due to increased regulation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps. If we reduce our use of swaps as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Periods of high demand for oil field services and equipment and the ability of suppliers to meet that demand may limit our ability to drill and produce our oil and gas properties.

Our industry is cyclical and, from time to time, well service providers and related equipment and personnel may be in short supply. These shortages can cause escalating prices, delays in drilling and other exploration activities and the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures may increase the actual cost of services, extend the time to secure such services and add costs for damages due to any accidents sustained from the overuse of equipment and inexperienced personnel. After a period of general declines in oilfield service and equipment costs following commodity price decreases, such costs could increase as commodity prices rise and may limit our ability to drill and produce our oil and gas properties.

If crude oil and natural gas prices decline to near or below the low levels experienced in 2015 and 2016 we could be required to record additional impairments of proved oil and gas properties that would constitute a charge to earnings and reduce our shareholders' equity.

At the end of each quarter, the net book value of oil and gas properties, less related deferred income taxes, are limited to the "cost center ceiling" equal to (i) the sum of (A) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (B) the costs of unproved properties not being amortized, and (C) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and gas properties, less related deferred income taxes, over the cost center ceiling is recognized as an impairment of proved oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher commodity prices in the future result in a cost center ceiling in excess of the net book value of oil and gas properties, less related deferred income taxes.

The estimated future net revenues used in the cost center ceiling are calculated using the 12-Month Average Realized Price. Primarily due to declines in the 12-Month Average Realized Price of crude oil, we recognized no impairments of proved oil and gas properties for the year ended December 31, 2017 and $576.5 million for the year ended December 31, 2016. Declines in the 12-Month Average Realized Price of crude oil in subsequent quarters would result in a lower present value of the estimated future net revenues from proved oil and gas reserves and may result in additional impairments of proved oil and gas properties.

Unproved properties, not being amortized, are assessed on a quarterly basis to determine whether or not and to what extent proved reserves have been assigned to the properties or if an impairment has occurred, in which case the related costs along with associated capitalized interest are added to the oil and gas property costs subject to amortization. This assessment requires the use of judgment and estimates all of which may prove to be inaccurate. If crude oil and natural gas prices decline from their current levels, we may need to write down the carrying value of our unproved oil and gas properties, which will result in increased DD&A for future periods.

An impairment does not impact cash flows from operating activities but does reduce earnings and our shareholders' equity and increases the balance sheet leverage as measured by debt-to-total capitalization. The risk that we will be required to recognize impairments of our proved oil and gas properties increases during periods of low or declining oil or gas prices. In addition, impairments would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues, as further discussed under "-Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future." We have in the past and could in the future incur additional impairments of oil and gas properties, particularly if oil and natural gas prices decline or remain at low levels.

A valuation allowance on a deferred tax asset could reduce our earnings.

Deferred tax assets are recorded for net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The ultimate realization of the deferred tax assets is dependent upon the generation of future taxable income during the periods in which those deferred tax assets would be deductible. We assess the realizability of the deferred tax assets each period by considering whether it is more likely than not that all or a portion of our deferred tax assets will not be realized. If we conclude that it is more likely than not that the deferred tax assets will not be realized, we record a valuation allowance against the net deferred tax asset, which has occurred since 2015 where we recorded a valuation allowance, reducing the net deferred tax asset to zero. This valuation allowance reduces earnings and our shareholders' equity and increases the balance sheet leverage as measured by debt-to-total capitalization. The valuation allowance remained as of December 31, 2017, and will remain until such time, if ever, that we can determine that the net deferred tax assets are more likely than not to be realized.

The taxation of independent producers is subject to change, and federal and state proposals being considered could increase our cost of doing business.

From time to time, legislative proposals are made that would, if enacted into law, make significant changes to United States tax laws, including the elimination or postponement of certain key United States federal income tax incentives currently available to independent producers of oil and natural gas. Proposals that would significantly affect us could include a repeal of the expensing of intangible drilling costs, a repeal of the percentage depletion allowance and an increase in the amortization period of geological and geophysical expenses. These changes, if enacted, will make it more costly for us to explore for and develop our oil and natural gas resources.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in the oil and gas leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available and, in all instances, we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. Even then, the cost of performing detailed title work can be expensive. We may choose to forgo detailed title examination by title lawyers on a portion of the mineral leases that we place in a drilling unit or conduct less title work than we have traditionally performed. As is customary in our industry, we generally rely upon the judgment of oil and gas lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and before drilling a well on a leased tract. We, in some cases, perform curative work to correct deficiencies in the marketability or adequacy of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected oil and gas leases can be generally lost and the target area can become undrillable. The failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

The threat and impact of terrorist attacks, cyber attacks or similar hostilities may adversely impact our operations.

We face various security threats, including attempts by third parties to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts and acts of war. These threats relate both to information relating to us and to third parties with whom we do business including landowners, employees, suppliers, customers and others. There can be no assurance that the procedures and controls we use to monitor these threats and mitigate our exposure to them will be sufficient in preventing them from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial condition, results of operations, or cash flows.

In particular, the oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling activities, conduct reservoir modeling and reserves estimation, and to process and record financial and operating data. We depend on digital technology, including information systems and related infrastructure as well as cloud application and services, to store, transmit, process and record sensitive information (including trade secrets, employee information and financial and operating data), communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. The complexity of the technologies needed to explore for and develop oil, natural gas and NGLs makes certain information more attractive to thieves.

Our business partners, including vendors, service providers, operating partners, purchasers of our production, and financial institutions, are also dependent on digital technology. Some of these business partners may be provided limited access to our sensitive information or our information systems and related infrastructure in the ordinary course of business.

As dependence on digital technologies has increased so has the risk of cyber incidents, including deliberate attacks and unintentional events. Our technologies, systems and networks, and those of others with whom we do business, may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, theft of property or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations. We may be the target of such attacks and we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any security vulnerabilities.

We cannot assess the extent of either the threat or the potential impact of future terrorist attacks on the energy industry in general, and on us in particular, either in the short-term or in the long-term. Uncertainty surrounding such attacks may affect our operations in unpredictable ways.

Certain anti-takeover provisions may affect your rights as a shareholder.

Our articles of incorporation authorize our board of directors to set the terms of and issue preferred stock without shareholder approval. Our board of directors could use the preferred stock as a means to delay, defer or prevent a takeover attempt that a shareholder might consider to be in our best interest. In addition, our revolving credit facility, our indentures governing our senior notes and our existing Preferred Stock contain terms that may restrict our ability to enter into change of control transactions, including requirements to repay borrowings under our revolving credit facility and to offer to repurchase senior notes or to redeem our Preferred Stock, in either event upon a change in control, as determined under the relevant documents relating to such indebtedness or Preferred Stock. These provisions, along with specified provisions of the Texas Business Organizations Code and our articles of incorporation and bylaws, may discourage or impede transactions involving actual or potential changes in our control, including transactions that otherwise could involve payment of a premium over prevailing market prices to holders of our common stock.

Failure to adequately protect critical data and technology systems could materially affect our operations.

Information technology solution failures, network disruptions and breaches of data security could disrupt our operations by causing delays or cancellation of customer orders, impeding processing of transactions and reporting financial results, resulting in the unintentional disclosure of customer, employee or our information, or damage to our reputation. There can be no assurance that a system failure or data security breach will not have a material adverse effect on our financial condition, results of operations or cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding our properties is included in “Item 1. Business” above and in “Note 3. Acquisitions and Divestitures of Oil and Gas Properties” and “Note 4. Property and Equipment, Net” of the Notes to our Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data,” which information is incorporated herein by reference.

Item 3. Legal Proceedings

From time to time, we are party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial position or results of operations.

Barrow-Shaver Litigation

On September 24, 2014 an unfavorable jury verdict was delivered against the Company in a case entitled Barrow-Shaver Resources Company v. Carrizo Oil & Gas, Inc. in the amount of $27.7 million. On January 5, 2015 the court entered a judgment awarding the verdict amount plus $2.9 million in attorney fees plus pre-judgment interest. On January 31, 2017, the Twelfth Court of Appeals at Tyler, Texas reversed the trial court decision and rendered judgment in favor of the Company, declaring that the plaintiff take nothing on any of its claims. The plaintiff has filed a motion for rehearing with the Twelfth Court of Appeals at Tyler, Texas and has petitioned the Texas Supreme Court to accept the case for review. Although the Texas Supreme Court has not accepted the case for review, it has asked the parties for briefing on the merits of the dispute. The payment of damages per the original judgment was superseded by posting a bond in the amount of $25.0 million, which will remain outstanding pending resolution of the appeals process (which could take an extended period of time) or agreement of the parties.

The case was filed September 19, 2012 in the 7th Judicial District Court of Smith County, Texas and arises from an agreement between the plaintiff and the Company whereby the plaintiff could earn an assignment of certain of the Company's leasehold interests in Archer and Baylor counties, Texas for each commercially productive oil and gas well drilled by the plaintiff on acreage covered by the agreement. The agreement contained a provision that the plaintiff had to obtain the Company's written consent to any assignment of rights provided by such agreement. The plaintiff subsequently entered into a purchase and sale agreement with a third-party purchaser allowing the third-party purchaser to purchase rights in approximately 62,000 leasehold acres, including the rights under the agreement with the Company, for approximately $27.7 million. The plaintiff requested the Company's consent to make the assignment to the third-party purchaser and the Company refused. The plaintiff alleged that, as a result of the Company's refusal, the third-party purchaser terminated such purchase and sale agreement. The plaintiff sought damages for breach of contract, tortious interference with existing contract and other grounds in an amount not to exceed $35.0 million plus exemplary damages and attorney's fees. As mentioned previously, the Twelfth Court of Appeals at Tyler, Texas found in favor of the Company on all grounds.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

Market Information. Our common stock, par value $0.01 per share, trades on the NASDAQ Global Select Market under the symbol "CRZO." The following table sets forth the high and low intraday sales prices per share of our common stock on the NASDAQ Global Select Market for the periods indicated.

	High	Low
2017		
First Quarter	$39.48	$26.08
Second Quarter	30.19	15.05
Third Quarter	18.46	11.10
Fourth Quarter	22.21	14.36
2016		
First Quarter	$32.45	$16.10
Second Quarter	42.49	28.51
Third Quarter	41.17	29.52
Fourth Quarter	43.96	32.00

Owners of Record. The closing market price of our common stock on February 23, 2018 was $18.44 per share. As of February 23, 2018, there were an estimated 63 owners of record of our common stock.

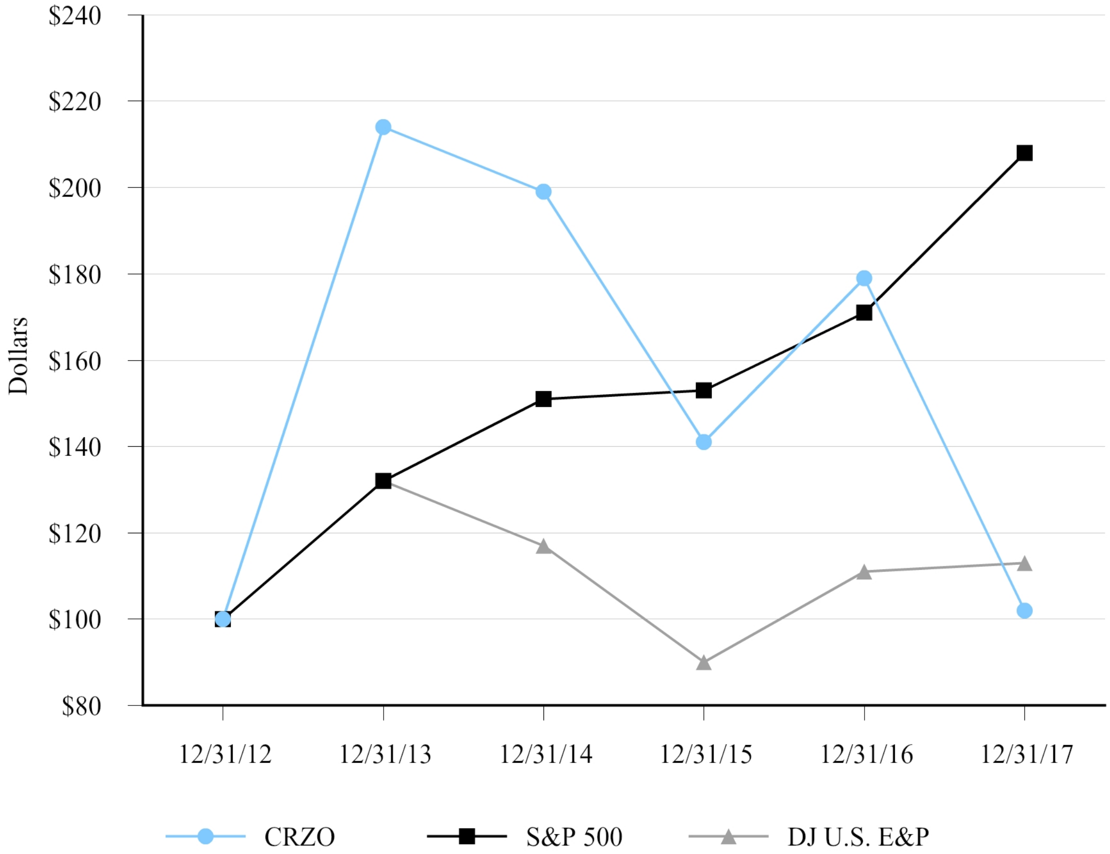
Common Stock Dividends. We have not paid any dividends on our common stock in the past and do not intend to pay such dividends in the foreseeable future. We currently intend to retain any earnings for the future operation and development of our business, including exploration, development and acquisition activities. Our revolving credit facility, our senior notes and the terms of our preferred stock restrict our ability to pay dividends. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

Purchases of Equity Securities by the Issuer and Affiliated Purchasers. For the year ended December 31, 2017, there were no purchases made by the Company or affiliated purchasers (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of shares of the Company's common stock.

Common Stock Total Return Performance Graph. The following performance graph contained in this section is not deemed to be "soliciting material" or to be "filed" with the SEC, and will not be incorporated by reference into any other filings under the Securities Act of 1933, as amended (the "Securities Act") or Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates it by reference into such filing. Shareholders are cautioned against drawing any conclusions from the data contained therein, as past results are not necessarily indicative of future financial performance.

The performance graph below presents a comparison of the yearly percentage change in the cumulative total return on our common stock over the period from December 31, 2012 to December 31, 2017, with the cumulative total return of the S&P 500 Index and the Dow Jones U.S. Exploration & Production Index, over the same period.

The graph assumes an investment of $100 (with reinvestment of all dividends) was invested on December 31, 2012, in our common stock at the closing market price at the beginning of this period and in each of the other two indexes.



	CRZO	S&P 500	DJ U.S. E&P
December 31, 2012	$100	$100	$100
December 31, 2013	$214	$132	$132
December 31, 2014	$199	$151	$117
December 31, 2015	$141	$153	$90
December 31, 2016	$179	$171	$111
December 31, 2017	$102	$208	$113

See “Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters” for information regarding shares of common stock authorized for issuance under our stock incentive plans.

Item 6. Selected Financial Data

Our financial information set forth below for each of the five years in the period ended December 31, 2017, has been derived from information included in our audited consolidated financial statements. This information should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our Consolidated Financial Statements and related Notes included in "Item 8. Financial Statements and Supplementary Data."

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(In thousands, except per share data)				
Statements of Operations Information:					
Total revenues	$745,888	$443,594	$429,203	$710,187	$520,182
Total costs and expenses	654,748	1,119,068	1,727,963	359,977	485,421
Income (loss) from continuing operations	87,110	(675,474)	(1,157,885)	222,283	21,858
Net income (loss) attributable to common shareholders	78,467	(675,474)	(1,155,154)	222,283	21,858
Income (loss) from continuing operations per common share:					
Basic	$1.19	($11.27)	($22.50)	$4.90	$0.54
Diluted	$1.18	($11.27)	($22.50)	$4.81	$0.53
Net income (loss) attributable to common shareholders per common share:					
Basic	$1.07	($11.27)	($22.45)	$4.90	$0.54
Diluted	$1.06	($11.27)	($22.45)	$4.81	$0.53
Weighted average common shares outstanding:					
Basic	73,421	59,932	51,457	45,372	40,781
Diluted	73,993	59,932	51,457	46,194	41,355
Statements of Cash Flows Information:					
Net cash provided by operating activities from continuing operations	$422,981	$272,768	$378,735	$502,275	$367,474
Net cash used in investing activities from continuing operations	(1,159,452)	(619,832)	(673,376)	(940,676)	(509,885)
Net cash provided by financing activities from continuing operations	741,817	308,340	330,767	300,290	120,326
Balance Sheet Information:					
Working capital	($249,944)	($138,971)	($50,636)	($141,278)	($32,138)
Total assets	2,778,304	1,626,327	2,007,246	2,962,305	2,094,364
Long-term debt	1,629,209	1,325,418	1,236,017	1,332,175	883,851
Preferred stock	214,262	—	—	—	—
Total shareholders' equity	370,897	23,458	444,054	1,103,441	841,604

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our Consolidated Financial Statements and related Notes included in "Item 8. Financial Statements and Supplementary Data." The following discussion and analysis contains statements, including, but not limited to, statements relating to our plans, strategies, objectives, and expectations. Please see "Forward-Looking Statements" and "Item 1A. Risk Factors" for further details about these statements.

General Overview

Significant Developments in 2017

- As a result of our Spring 2017 borrowing base redetermination, our borrowing base was increased from $600.0 million to $900.0 million, with an elected commitment amount of $800.0 million.
- As a result of our Fall 2017 borrowing base redetermination, our borrowing base was established at $900.0 million, with an elected commitment amount of $800.0 million. The calculation of the $900.0 million borrowing base was supported solely by the reserves of our Eagle Ford and Delaware Basin assets.
- In the third quarter of 2017, we closed on the ExL Acquisition, which added 16,508 net acres to our portfolio, for aggregate net consideration of $679.8 million. In addition, we have agreed to a contingent payment of $50.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2021 with a cap of $125.0 million.
- We funded the ExL Acquisition through the following financing activities during the third quarter of 2017:
    - public offering of 15.6 million shares of our common stock at a price per share of $14.28 for net proceeds of $222.4 million, net of offering costs;
    - public offering of $250.0 million aggregate principal amount of 8.25% Senior Notes due 2025 for net proceeds of $245.4 million, net of underwriting discounts and commissions and offering costs; and
    - issuance and sale of (i) $250.0 million (250,000 shares) of 8.875% redeemable preferred stock and (ii) warrants for 2,750,000 shares of our common stock for net proceeds of $236.4 million, net of issuance costs
- In the fourth quarter of 2017, we closed on divestitures of substantially all of our assets in the Utica and Marcellus Shales for aggregate net proceeds of approximately $137.0 million, subject to post-closing adjustments. In addition, we could receive combined contingent consideration from the two divestitures of up to $8.0 million per year with a cap of $22.5 million if crude oil and natural gas prices exceed specified thresholds for each of the years of 2018 through 2020.
- Also in the fourth quarter of 2017, we entered into purchase and sale agreements to sell substantially all of our assets in the Niobrara Formation and a portion of our assets in the Eagle Ford. Carrizo has received aggregate net proceeds of $382.8 million for these divestitures, subject to post-closing adjustments, both of which closed in January 2018. In addition, we could receive contingent consideration of $5.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2020 as part of the Niobrara Formation divestiture.
- In the fourth quarter of 2017, we redeemed $150.0 million of the $600.0 million aggregate principal amount outstanding of 7.50% Senior Notes due 2020.

Recent Developments

- In January 2018, we called for redemption a total of $320.0 million aggregate principal amount of the outstanding 7.50% Senior Notes. The proceeds for these redemptions were primarily from the Niobrara and Eagle Ford Shale divestitures discussed above. After these redemptions, we will have $130.0 million aggregate principal amount of 7.50% Senior Notes outstanding.
- In January 2018, we redeemed 50,000 of the shares of Preferred Stock, representing 20% of the issued and outstanding Preferred Stock, for $50.5 million, which consisted of $1,000.00 per share of Preferred Stock redeemed, plus accrued and unpaid dividends.
- In January 2018, as a result of the divestiture in the Eagle Ford Shale discussed above, our borrowing base under our revolving credit facility was reduced from $900.0 million to $830.0 million; however, the elected commitment amount remained unchanged at $800.0 million.

- Our 2018 drilling, completion, and infrastructure capital expenditure plan is currently $750.0 million to $800.0 million, of which 57% is allocated to the Eagle Ford and the remaining 43% allocated to the Delaware Basin. See "—Liquidity and Capital Resources—2018 Drilling, Completion, and Infrastructure Capital Expenditure Plan and Funding Strategy" for additional details.

Results of Operations

Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the years ended December 31, 2017 and 2016:

	Years Ended December 31,		2017 Period Compared to 2016 Period	
	2017	2016	Increase (Decrease)	% Increase (Decrease)
Total production volumes				
Crude oil (MBbls)	12,566	9,423	3,143	33%
NGLs (MBbls)	2,327	1,788	539	30%
Natural gas (MMcf)	28,472	25,574	2,898	11%
Total barrels of oil equivalent (MBoe)	19,639	15,473	4,166	27%
Daily production volumes by product				
Crude oil (Bbls/d)	34,428	25,745	8,683	34%
NGLs (Bbls/d)	6,376	4,885	1,491	31%
Natural gas (Mcf/d)	78,006	69,873	8,133	12%
Total barrels of oil equivalent (Boe/d)	53,805	42,276	11,529	27%
Daily production volumes by region (Boe/d)				
Eagle Ford	37,825	30,664	7,161	23%
Delaware Basin	6,713	1,115	5,598	502%
Niobrara	2,558	2,931	(373)	(13%)
Marcellus	6,122	6,329	(207)	(3%)
Utica and other	587	1,237	(650)	(53%)
Total barrels of oil equivalent (Boe/d)	53,805	42,276	11,529	27%
Average realized prices				
Crude oil ($ per Bbl)	$50.39	$40.12	$10.27	26%
NGLs ($ per Bbl)	20.37	12.54	7.83	62%
Natural gas ($ per Mcf)	2.29	1.69	0.60	36%
Total average realized price ($ per Boe)	$37.98	$28.67	$9.31	32%
Revenues (In thousands)				
Crude oil	$633,233	$378,073	$255,160	67%
NGLs	47,405	22,428	24,977	111%
Natural gas	65,250	43,093	22,157	51%
Total revenues	$745,888	$443,594	$302,294	68%

Production volumes in 2017 were 53,805 Boe/d, an increase of 27% from 42,276 Boe/d in 2016. The increase is primarily due to production from our wells in the Eagle Ford and Delaware Basin and the addition of production from the Sanchez Acquisition in late 2016 and the ExL Acquisition in the third quarter of 2017, partially offset by the divestitures in the Marcellus and Utica Shales. Revenues for 2017 increased 68% to $745.9 million compared to $443.6 million in 2016 primarily due to higher commodity prices and increased production.

Lease operating expenses for 2017 increased to $139.9 million ($7.12 per Boe) from $98.7 million ($6.38 per Boe) in 2016. The increase in lease operating expenses is primarily due to increased production and increased workover costs primarily on wells acquired in the Sanchez Acquisition. The increase in lease operating expense per Boe is primarily due to the workover costs described above as well as to an increased proportion of total production from crude oil properties, which have a higher operating cost per Boe than natural gas properties.

Production taxes increased to $32.5 million (or 4.4% of revenues) in 2017 from $19.0 million (or 4.3% of revenues) in 2016 as a result of the increase in crude oil, NGL, and natural gas revenues. The increase in production taxes as a percentage of revenues for 2017 as compared to 2016 is due primarily to a decreased proportion of total revenues attributable to Marcellus production, which is not subject to production taxes.

Ad valorem taxes increased to $7.3 million in 2017 from $5.6 million in 2016. The increase in ad valorem taxes is due to new wells drilled in the Eagle Ford and Delaware Basin in 2016 and new wells acquired in the Sanchez Acquisition in December 2016.

Depreciation, depletion and amortization ("DD&A") expense for 2017 increased $48.6 million to $262.6 million ($13.37 per Boe) from $214.0 million ($13.83 per Boe) for 2016. The increase in DD&A expense is attributable to increased production, partially offset by the decrease in the DD&A rate per Boe. The decrease in the DD&A rate per Boe is due primarily to impairments of our proved oil and gas properties recorded during 2016, reductions in estimated future development costs as a result of reduced service costs that occurred in the fourth quarter of 2016, and the addition of crude oil reserves in the fourth quarter of 2017, partially offset by the allocation to proved oil and gas properties related to the ExL Acquisition. The components of our DD&A expense were as follows:

	Years Ended December 31,	
	2017	2016
	(In thousands)	
DD&A of proved oil and gas properties	$257,057	$208,849
Depreciation of other property and equipment	2,484	2,613
Amortization of other assets	1,249	1,136
Accretion of asset retirement obligations	1,799	1,364
Total DD&A	$262,589	$213,962

We did not recognize impairments of proved oil and gas properties for the year ended December 31, 2017. Primarily due to declines in the 12-Month Average Realized Price of crude oil, we recognized impairments of proved oil and gas properties in 2016. Details of the 12-Month Average Realized Price of crude oil for 2017 and 2016 and impairments of proved oil and gas properties for 2016 are summarized in the table below:

	Years Ended December 31,	
	2017	2016
Impairment of proved oil and gas properties (in thousands)	$—	$576,540
Crude Oil 12-Month Average Realized Price ($/Bbl) - Beginning of period	$39.60	$47.24
Crude Oil 12-Month Average Realized Price ($/Bbl) - End of period	$49.87	$39.60
Crude Oil 12-Month Average Realized Price percentage increase (decrease) during period	26%	(16%)

General and administrative expense, net decreased to $66.2 million for 2017 from $75.0 million for 2016. The decrease was primarily due to a decrease in stock-based compensation, net as a result of a decrease in the fair value of stock appreciation rights for 2017 due to exercises and expirations and a decrease in fair value of stock appreciation rights in 2017 as compared to an increase in the fair value of stock appreciation rights in 2016, partially offset by higher compensation costs for 2017 as compared to 2016, resulting from an increase in personnel as well as higher annual bonuses awarded in the first quarter of 2017 compared to the first quarter of 2016.

We recorded a loss on derivatives, net of $59.1 million for the year ended December 31, 2017 and a loss on derivatives, net of $49.1 million for the year ended December 31, 2016. The components of our (gain) loss on derivatives, net were as follows:

	Years Ended December 31,	
	2017	2016
	(In thousands)	
Crude oil derivative positions:		
(Gain) loss due to an overall (downward) upward shift in the futures curve of forecasted crude oil prices during the period on derivative positions outstanding at the beginning of the period	($22,951)	$9,664
Loss due to new derivative positions executed during the period (1)	45,790	13,945
Loss due to deferred premium obligations incurred	18,401	5,782
Natural gas derivative positions:		
Gain due to downward shift in the futures curve of forecasted natural gas prices during the period on derivative positions outstanding at the beginning of the period	(15,399)	—
Loss due to new derivative positions executed during the period (1)	—	19,584
Loss due to deferred premium obligations incurred	—	98
NGL derivative positions:		
Loss due to new derivative positions executed during the period (1)	1,322	—
Contingent consideration (2):		
Loss due to upward shift in the futures curve of forecasted commodity prices from the closing date to the end of the period	31,940	—
(Gain) loss on derivatives, net	$59,103	$49,073

(1) The new derivative positions executed during 2017 and 2016 were in a loss due to an upward shift in the futures curve of forecasted commodity prices for crude oil, NGLs and natural gas subsequent to the respective contract executions.

(2) We have entered into agreements for acquisitions and divestitures of oil and gas properties containing contingent consideration that are required to be bifurcated and accounted for separately as derivative instruments as they are not clearly and closely related to the host contract. See "Note 11. Derivative Instruments" and "Note 12. Fair Value Measurements" for further discussion of the contingent consideration.

Interest expense, net for 2017 was $80.9 million as compared to $79.4 million for 2016. The increase was primarily due to the interest expense on the $250.0 million aggregate principal amount of our 8.25% Senior Notes that were issued in July 2017 and an increase in interest expense on our revolving credit facility as a result of increased borrowings in 2017 as compared to 2016, partially offset by an increase in capitalized interest as a result of higher average balances of unevaluated leasehold and seismic costs for 2017 as compared to 2016, primarily due to the ExL Acquisition. The components of our interest expense, net were as follows:

	Years Ended December 31,	
	2017	2016
	(In thousands)	
Interest expense on Senior Notes	$95,272	$85,819
Interest expense on revolving credit facility	8,293	3,907
Amortization of debt issuance costs, premiums, and discounts	4,529	5,565
Other interest expense	1,029	1,138
Capitalized interest	(28,253)	(17,026)
Interest expense, net	$80,870	$79,403

As a result of our redemption of $150.0 million aggregate principal amount of our 7.50% Senior Notes, we recorded a loss on extinguishment of debt of $4.2 million in 2017, which includes the redemption premium paid to redeem the notes and non-cash charges of $1.3 million attributable to the write-off of unamortized premium and debt issuance costs associated with the 7.50% Senior Notes.

The effective income tax rate was 4.4% for 2017 and 0% for 2016. The variance in the effective income tax rate results from income tax expense of $4.0 million recognized during 2017 primarily as a result of the significant changes in our operations in 2017, including the ExL Acquisition in the Delaware Basin and divestitures of substantially all of our assets in the Utica and Marcellus Shales, which resulted in changes to our anticipated future state apportionment for estimated state deferred tax liabilities. For the year ended December 31, 2016, the effective income tax rate was 0% as a result of a full valuation allowance against our net deferred tax assets driven by the impairments of proved oil and gas properties we recognized beginning in the third quarter of 2015 and continuing through the third quarter of 2016.

For the year ended December 31, 2017, we declared and paid $7.8 million of dividends, in cash, to the holders of record of the Preferred Stock, which reduced net income to compute net income attributable to common shareholders.

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the years ended December 31, 2016 and 2015:

	Years Ended December 31,		2016 Period Compared to 2015 Period	
	2016	**2015**	**Increase (Decrease)**	**% Increase (Decrease)**
Total production volumes				
Crude oil (MBbls)	9,423	8,415	1,008	12%
NGLs (MBbls)	1,788	1,352	436	32%
Natural gas (MMcf)	25,574	21,812	3,762	17%
Total barrels of oil equivalent (MBoe)	15,473	13,402	2,071	15%
Daily production volumes by product				
Crude oil (Bbls/d)	25,745	23,054	2,691	12%
NGLs (Bbls/d)	4,885	3,705	1,180	32%
Natural gas (Mcf/d)	69,873	59,758	10,115	17%
Total barrels of oil equivalent (Boe/d)	42,276	36,719	5,557	15%
Daily production volumes by region (Boe/d)				
Eagle Ford	30,664	26,377	4,287	16%
Delaware Basin	1,115	104	1,011	972%
Niobrara	2,931	2,957	(26)	(1%)
Marcellus	6,329	5,850	479	8%
Utica and other	1,237	1,431	(194)	(14%)
Total barrels of oil equivalent (Boe/d)	42,276	36,719	5,557	15%
Average realized prices				
Crude oil ($ per Bbl)	$40.12	$44.69	($4.57)	(10%)
NGLs ($ per Bbl)	12.54	11.54	1.00	9%
Natural gas ($ per Mcf)	1.69	1.72	(0.03)	(2%)
Total average realized price ($ per Boe)	$28.67	$32.03	($3.36)	(10%)
Revenues (In thousands)				
Crude oil	$378,073	$376,094	$1,979	1%
NGLs	22,428	15,608	6,820	44%
Natural gas	43,093	37,501	5,592	15%
Total revenues	$443,594	$429,203	$14,391	3%

Production volumes in 2016 were 42,276 Boe/d, an increase of 15% from 36,719 Boe/d in 2015. The increase is primarily due to production from our wells in the Eagle Ford and Delaware Basin. Revenues for 2016 increased 3% to $443.6 million compared to $429.2 million in 2015 primarily due to the increase in crude oil production, partially offset by a decrease in average realized crude oil prices of 10% for 2016 as compared to 2015.

Lease operating expenses for 2016 increased to $98.7 million ($6.38 per Boe) from $90.1 million ($6.72 per Boe) in 2015. The increase in lease operating expenses is primarily due to increased production from new wells in the Eagle Ford, partially offset by reduced costs due primarily to a decrease in produced water disposal costs resulting from a higher proportion of produced water volumes being transported to disposal sites via pipeline instead of truck as well as lower costs to transport produced water to disposal sites via truck. The decrease in lease operating expense per Boe is primarily due to the lower produced water disposal costs described above.

Production taxes increased to $19.0 million (or 4.3% of revenues) in 2016 from $17.7 million (or 4.1% of revenues) in 2015 as a result of the increase in natural gas and NGL revenues. The increase in production taxes as a percentage of revenues for 2016 as compared to 2015 is due primarily to an increased proportion of total revenues attributable to natural gas and NGLs in Eagle Ford and the Delaware Basin, which is taxed at a higher rate than crude oil.

Ad valorem taxes decreased to $5.6 million in 2016 from $9.3 million in 2015. The decrease in ad valorem taxes is due to lower property tax valuations received during 2016 as compared to 2015, partially offset by an increase attributable to new wells drilled in Eagle Ford in 2015.

DD&A expense for 2016 decreased $86.0 million to $214.0 million ($13.83 per Boe) from $300.0 million ($22.39 per Boe) for 2015. The decrease in DD&A expense is attributable to the decrease in the DD&A rate per Boe, partially offset by increased production. The DD&A rate per Boe decreased primarily due to impairments of our proved oil and gas properties recorded during 2015 and 2016 as well as reductions in estimated future development costs primarily as a result of reduced service costs that have occurred since 2015. The components of our DD&A expense were as follows:

	Years Ended December 31,	
	2016	2015
	(In thousands)	
DD&A of proved oil and gas properties	$208,849	$295,452
Depreciation of other property and equipment	2,613	1,932
Amortization of other assets	1,136	1,539
Accretion of asset retirement obligations	1,364	1,112
Total DD&A	$213,962	$300,035

We recognized impairments of proved oil and gas properties for the years ended December 31, 2016 and 2015 primarily due to declines in the 12-Month Average Realized Price of crude oil, as summarized in the table below:

	Years Ended December 31,	
	2016	2015
Impairment of proved oil and gas properties (in thousands)	$576,540	$1,224,367
Crude Oil 12-Month Average Realized Price ($/Bbl) - Beginning of period	$47.24	$92.24
Crude Oil 12-Month Average Realized Price ($/Bbl) - End of period	$39.60	$47.24
Crude Oil 12-Month Average Realized Price percentage increase (decrease) during period	(16%)	(49%)

General and administrative expense, net increased to $75.0 million for 2016 from $67.2 million for 2015. The increase was primarily due to an increase in the fair value of stock appreciation rights in 2016 as compared to a decrease in fair value in 2015, partially offset by lower annual bonuses awarded in the first quarter of 2016 as compared to the first quarter of 2015.

We recorded a loss on derivatives, net of $49.1 million for 2016 and a gain on derivatives, net of $99.3 million for 2015. The components of our (gain) loss on derivatives, net were as follows:

	Years Ended December 31,	
	2016	2015
	(In thousands)	
Crude oil derivative positions:		
(Gain) loss due to (downward) upward shift in the futures curve of forecasted crude oil prices during the period on derivative positions outstanding at the beginning of the period	$9,664	($11,462)
(Gain) loss due to new derivative positions executed during the period (1)	13,945	(88,163)
Loss due to deferred premium obligations incurred	5,782	4,426
Natural gas derivative positions:		
Gain due to downward shift in the futures curve of forecasted natural gas prices during the period on derivative positions outstanding at the beginning of the period	—	(4,062)
Loss due to new derivative positions executed during the period (1)	19,584	—
Loss due to deferred premium obligations incurred	98	—
(Gain) loss on derivatives, net	$49,073	($99,261)

(1) The new derivative positions executed during 2016 were in a loss due to an upward shift in the futures curve of forecasted commodity prices for crude oil and natural gas subsequent to the respective contract executions.

Interest expense, net for 2016 was $79.4 million as compared to $69.2 million for 2015. The increase was primarily due to the decrease in capitalized interest as a result of lower average balances of unevaluated leasehold and seismic costs and exploratory well costs for 2016 as compared to 2015, partially offset by lower interest associated with the $650.0 million of 6.25% Senior Notes that were issued in April 2015 as compared to the interest associated with the $600.0 million of 8.625% Senior Notes that were redeemed in April 2015. The components of our interest expense, net were as follows:

	Years Ended December 31,	
	2016	2015
	(In thousands)	
Interest expense on Senior Notes	$85,819	$90,882
Interest expense on revolving credit facility	3,907	4,226
Amortization of debt issuance costs, premiums, and discounts	5,565	4,724
Other interest expense	1,138	1,453
Capitalized interest	(17,026)	(32,090)
Interest expense, net	$79,403	$69,195

The effective income tax rates for 2016 and 2015 were 0% and 10.8%, respectively. This reduction in the effective income tax rate is primarily a result of recording a full valuation allowance against our net deferred tax assets beginning in the third quarter of 2015, primarily driven by the impairments of proved oil and gas properties described above.

Liquidity and Capital Resources

2018 Drilling, Completion, and Infrastructure Capital Expenditure Plan and Funding Strategy. Our 2018 drilling, completion, and infrastructure capital expenditure plan is $750.0 million to $800.0 million. This incorporates an assumed double-digit increase in oilfield service costs as well as operating two drilling rigs in the Eagle Ford Shale and three to four drilling rigs in the Delaware Basin during 2018, as well as two to three completion crews during the year. We currently intend to finance our 2018 drilling, completion, and infrastructure capital expenditure plan primarily from the sources described below under "—Sources and Uses of Cash." Our capital program could vary depending upon various factors, including, but not limited to, the availability of drilling rigs and completion crews, the cost of completion services, acquisitions and divestitures of oil and gas properties, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors. The following is a summary of our 2017 capital expenditures:

	Three Months Ended				Year Ended
	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017	December 31, 2017
	(In thousands)				
Drilling, completion, and infrastructure					
Eagle Ford	$111,472	$129,933	$122,281	$100,323	$464,009
Delaware Basin	10,360	11,727	36,055	102,078	160,220
All other regions	6,412	6,734	6,698	7,951	27,795
Total drilling, completion, and infrastructure	128,244	148,394	165,034	210,352 (1)	652,024 (1)
Leasehold and seismic	14,516	34,447	11,819	4,549	65,331
Total (2)	$142,760	$182,841	$176,853	$214,901	$717,355

(1) Includes amounts related to the divested assets in the Utica, Marcellus, Niobrara and Eagle Ford of approximately $22.1 million and $30.2 million for the three months ended December 31, 2017 and for the year ended December 31, 2017, respectively, which consists of drilling and completion capital expenditures incurred between the effective date and close date of the divestitures. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" of the Notes to our Consolidated Financial Statements for further details of these divestitures.

(2) Capital expenditures exclude acquisitions of oil and gas properties, capitalized general and administrative expense, interest expense and asset retirement costs.

Sources and Uses of Cash. Our primary use of cash is related to our drilling, completion and infrastructure capital expenditures and, to a lesser extent, our leasehold and seismic capital expenditures. For the year ended December 31, 2017, we funded our capital expenditures with cash provided by operations and borrowings under our revolving credit facility. Potential sources of future liquidity include the following:

- *Cash provided by operations.* Cash flows from operations are highly dependent on crude oil prices. As such, we hedge a portion of our forecasted production to reduce our exposure to commodity price volatility in order to achieve a more predictable level of cash flows.

- *Borrowings under revolving credit facility*. As of February 23, 2018, our revolving credit facility had a borrowing base of $830.0 million, with an elected commitment amount of $800.0 million, with $141.0 million borrowings outstanding and no letters of credit issued, which reduce the amounts available under our revolving credit facility. In connection with the divestiture of a portion of our Eagle Ford acreage, the borrowing base was reduced from $900.0 million to $830.0 million effective with the closing of the divestiture on January 31, 2018; however, the elected commitment amount of $800.0 million remained unchanged. The amount we are able to borrow is subject to compliance with the financial covenants and other provisions of the credit agreement governing our revolving credit facility.

- *Securities offerings*. As situations or conditions arise, we may choose to issue debt, equity or other securities to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all. See "Note 6. Long-term Debt" of the Notes to our Consolidated Financial Statements for details of the issuance of the 8.25% Senior Notes, "Note 9. Preferred Stock and Warrants" of the Notes to our Consolidated Financial Statements for details of the Preferred Stock issuance and "Note 10. Shareholders' Equity and Stock-Based Compensation" of the Notes to our Consolidated Financial Statements for details of the recent common stock offering.

- *Divestitures*. We may consider divesting certain properties or assets that are not part of our core business or are no longer deemed essential to our future growth, provided we are able to divest such assets on terms that are acceptable to us. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" of the Notes to our Consolidated Financial Statements for further details of the divestitures that occurred in late 2017 and early 2018.

- *Joint ventures*. Joint ventures with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage or purchase a portion of interests, or both.

Overview of Cash Flow Activities. Net cash provided by operating activities from continuing operations was $423.0 million, $272.8 million and $378.7 million for the years ended December 31, 2017, 2016 and 2015, respectively. The increase from 2016 to 2017 was driven primarily by an increase in revenues as a result of higher production and commodity prices and a decrease in working capital requirements, partially offset by a decrease in the net cash received from derivative settlements and an increase in operating expenses and cash general and administrative expense. The decrease from 2015 to 2016 was due primarily to a decrease in the net cash received from derivative settlements and an increase in working capital requirements.

Net cash used in investing activities from continuing operations was $1,159.5 million, $619.8 million and $673.4 million for the years ended December 31, 2017, 2016 and 2015, respectively. The increase from 2016 to 2017 was due primarily to funding the ExL Acquisition and increased capital expenditures, primarily in the Eagle Ford Shale and the Delaware Basin, partially offset by increased net proceeds from divestitures of oil and gas properties, which primarily related to the divestitures of substantially all of our assets in the Marcellus Shale and Utica Shale as well as deposits received in connection with the divestitures of a portion of our assets in the Eagle Ford Shale and substantially all of our assets in the Niobrara. The decrease from 2015 to 2016 was due primarily to a reduction in our capital expenditures in 2016 as compared to 2015, partially offset by an increase related to the Sanchez Acquisition in the fourth quarter of 2016.

Net cash provided by financing activities from continuing operations for the years ended December 31, 2017, 2016 and 2015 was $741.8 million, $308.3 million and $330.8 million, respectively. The increase from 2016 to 2017 was due to net proceeds related to the issuance of the 8.25% Senior Notes, the sale of Preferred Stock, the sale of common stock, and increased borrowings net of repayments under our revolving credit facility in 2017 as compared to 2016, partially offset by the redemption of $150.0 million of the 7.50% Senior Notes, increased debt issuance costs related to the amendments to the credit agreement governing the revolving credit facility and dividends paid on the Preferred Stock. The decrease from 2015 to 2016 was primarily due to the proceeds from the issuance of common stock in March and October 2015 and the issuance of the 6.25% Senior Notes in April 2015, partially offset by the tender and redemption of the 8.625% Senior Notes during the second quarter of 2015, the payment of the deferred purchase payment in February 2015, proceeds from the issuance of common stock in October 2016, and decreased borrowings net of repayments under our revolving credit facility in 2016 as compared to 2015.

Economic downturns may adversely affect our ability to access capital markets in the future. Cash flows from operations are primarily driven by crude oil production, crude oil prices, and settlements of our crude oil derivatives. We currently believe that cash flows from operations and borrowings under our revolving credit facility will provide adequate financial flexibility and will be sufficient to fund our immediate cash flow requirements.

- *Revolving credit facility.* The borrowing base under our revolving credit facility is affected by assumptions of the administrative agent with respect to, among other things, crude oil and natural gas prices. Our borrowing base may decrease if our administrative agent reduces the crude oil and natural gas prices from those used to determine our existing borrowing base. See "—Sources and Uses of Cash—Borrowings under our revolving credit facility" and "—Financing Arrangements—Senior Secured Revolving Credit Facility" for further details of our revolving credit facility.

- *Divestitures.* In the fourth quarter of 2017, we entered into purchase and sale agreements to sell substantially all of our assets in the Niobrara Formation and a portion of our assets in the Eagle Ford. Carrizo received aggregate net proceeds of $382.8 million for these divestitures, subject to post-closing adjustments, both of which closed in January 2018.
- *Redemptions of 7.50% Senior Notes.* In January 2018, we called for redemption a total of $320.0 million aggregate principal amount of the outstanding 7.50% Senior Notes. The proceeds for these redemptions were primarily from the Niobrara and Eagle Ford divestitures discussed above. After these redemptions, we will have $130.0 million aggregate principal amount of 7.50% Senior Notes outstanding. As a result of these redemptions, we expect to record loss on extinguishment of debt of approximately $9.0 million during the first quarter of 2018.
- *Redemption of Preferred Stock.* In January 2018, we redeemed 50,000 of the shares of Preferred Stock for $50.5 million, which consisted of $1,000.00 per share of Preferred Stock redeemed, plus accrued and unpaid dividends.
- *Contingent consideration.* In connection with the ExL Acquisition, we agreed to a contingent payment of $50.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2021 with a cap of $125.0 million. In connection with the sale of our Utica Shale assets, we could receive contingent consideration of $5.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2020. In connection with the sale of our Marcellus Shale assets, we could receive contingent consideration of $3.0 million per year if natural gas prices exceed specified thresholds for each of the years of 2018 through 2020 with a cap of $7.5 million. In connection with the sale of our Niobrara Formation assets, we could receive contingent consideration of $5.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2020. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" of the Notes to our Consolidated Financial Statements for further details of each of these contingent considerations. See also "Item 7A. Qualitative and Quantitative Disclosures about Market Risk" for details of the sensitivities to commodity price of each contingent consideration.
- *Hedging.* To manage our exposure to commodity price risk and to provide a level of certainty in the cash flows to support our drilling, completion, and infrastructure capital expenditure plan, we hedge a portion of our forecasted production.

  As of February 23, 2018, we had the following outstanding derivative positions at weighted average contract prices:

Crude Oil Fixed Price Swaps

Period	Volumes (Bbls/d)	NYMEX Price ($/Bbl)
FY 2018	6,000	$49.55

Crude Oil Basis Swaps

Period	Volumes (Bbls/d)	LLS-NYMEX Price Differential ($/Bbl)
FY 2018	6,000	$2.91

Period	Volumes (Bbls/d)	Midland-NYMEX Price Differential ($/Bbl)
FY 2018	6,000	($0.10)

Crude Oil Three-Way Collars

		NYMEX Prices		
Period	Volumes (Bbls/d)	Sub-Floor Price ($/Bbl)	Floor Price ($/Bbl)	Ceiling Price ($/Bbl)
FY 2018	24,000	$39.38	$49.06	$60.14
FY 2019	12,000	$40.00	$48.40	$60.29

Crude Oil Net Sold Call Options

Period	Volumes (Bbls/d)	NYMEX Ceiling Price ($/Bbl)
FY 2018	3,388	$71.33
FY 2019	3,875	$73.66
FY 2020	4,575	$75.98

NGL Fixed Price Swaps

Period	OPIS Purity Ethane Mont Belvieu Non-TET		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPIS Isobutane Mont Belvieu Non-TET		OPIS Natural Gasoline Mont Belvieu Non-TET	
	Volumes (Bbls/d)	Price ($/Bbl)	Volumes (Bbls/d)	Price ($/Bbl)	Volumes (Bbls/d)	Price ($/Bbl)	Volumes (Bbls/d)	Price ($/Bbl)	Volumes (Bbls/d)	Price ($/Bbl)
FY 2018	2,200	$12.01	1,500	$34.23	200	$38.85	600	$38.98	600	$55.23

Natural Gas Fixed Price Swaps

Period	Volumes (MMBtu/d)	NYMEX Price ($/MMBtu)
March 2018 - December 2018	25,000	$3.01

Natural Gas Sold Call Options

Period	Volumes (MMBtu/d)	NYMEX Ceiling Price ($/MMBtu)
FY 2018	33,000	$3.25
FY 2019	33,000	$3.25
FY 2020	33,000	$3.50

If cash flows from operations and borrowings under our revolving credit facility and the other sources of cash described under "—Sources and Uses of Cash" are insufficient to fund our remaining 2018 drilling, completion, and infrastructure capital expenditure plan, we may need to reduce our capital expenditure plan or seek other financing alternatives. We may not be able to obtain financing needed in the future on terms that would be acceptable to us, or at all. If we cannot obtain adequate financing, we may be required to limit or defer a portion of our remaining 2018 drilling, completion, and infrastructure capital expenditure plan, thereby potentially adversely affecting the recoverability and ultimate value of our oil and gas properties. Based on existing market conditions and our expected liquidity needs, among other factors, we may use a portion of our cash flows from operations, proceeds from divestitures, securities offerings or borrowings to reduce debt or Preferred Stock prior to scheduled maturities through debt or Preferred Stock repurchases, either in the open market or in privately negotiated transactions, through debt or Preferred Stock redemptions or tender offers, or through repayments of bank borrowings.

Contractual Obligations

The following table sets forth estimates of our contractual obligations as of December 31, 2017 (in thousands):

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
Long-term debt (1)	$—	$—	$450,000	$—	$291,300	$904,425	$1,645,725
Cash interest on senior notes and other long-term debt (2)	98,260	95,194	95,194	61,444	61,444	83,236	494,772
Cash interest and commitment fees on revolving credit facility (3)	12,795	12,795	12,795	12,795	4,407	—	55,587
Capital leases	1,823	1,800	1,050	—	—	—	4,673
Operating leases	5,038	4,895	4,637	4,450	1,854	—	20,874
Drilling rig contracts (4)	23,885	8,881	—	—	—	—	32,766
Delivery commitments (5)	3,657	3,676	2,757	2,438	10	26	12,564
Asset retirement obligations and other (6)	2,115	479	300	132	229	22,821	26,076
Total Contractual Obligations (7)	$147,573	$127,720	$566,733	$81,259	$359,244	$1,010,508	$2,293,037

(1) Long-term debt consists of the principal amounts of the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023, the 8.25% Senior Notes due 2025, other long-term debt due 2028, and borrowings outstanding under our revolving credit facility which matures in 2022 (subject to a springing maturity date of June 15, 2020 if the 7.50% Senior Notes have not been refinanced on or prior to such time).

(2) Cash interest on senior notes and other long-term debt includes cash payments for interest on the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023, the 8.25% Senior Notes due 2025 and other long-term debt due 2028.

(3) Cash interest on our revolving credit facility was calculated using the weighted average interest rate of the outstanding borrowings under the revolving credit facility as of December 31, 2017 of 3.73%. Commitment fees on our revolving credit facility were calculated based on the unused portion of lender commitments as of December 31, 2017, at the applicable commitment fee rate of 0.375%.

(4) Drilling rig contracts represent gross contractual obligations and accordingly, other joint owners in the properties operated by us will generally be billed for their working interest share of such costs.

(5) Delivery commitments represent contractual obligations we have entered into for certain gathering, processing and transportation service agreements which require minimum volumes of natural gas to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any natural gas.
(6) Asset retirement obligations and other are based on estimates and assumptions that affect the reported amounts as of December 31, 2017. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results. See "Note 2. Summary of Significant Accounting Policies" of the Notes to our Consolidated Financial Statements for further discussion of estimates and assumptions that may affect the reported amounts.
(7) In connection with the ExL Acquisition, we have agreed to a contingent payment of $50.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2021 with a cap of $125.0 million, which is not included in the table above.

Contractual Obligations Executed Subsequent to December 31, 2017

In January and February 2018, we extended two of our current drilling rig contracts for terms of one and two years. The gross contractual obligations for these extended drilling rig contracts are approximately $22.2 million. Additionally, in January and February 2018, we entered into four produced water disposal contracts for terms between five and six years, which require delivery of minimum volumes. The gross contractual obligations for these produced water disposal contracts, which reflect the aggregate undiscounted deficiency fees assuming no delivery of any produced water, are approximately $111.6 million. The gross contractual obligations associated with these drilling rig and produced water disposal contracts are not included in the table above.

Off Balance Sheet Arrangements

We currently do not have any off balance sheet arrangements.

Financing Arrangements

Senior Secured Revolving Credit Facility

We have a senior secured revolving credit facility with a syndicate of banks that, as of December 31, 2017, had a borrowing base of $900.0 million, with an elected commitment amount of $800.0 million, and $291.3 million of borrowings outstanding at a weighted average interest rate of 3.73%. As of December 31, 2017, we had $0.4 million in letters of credit outstanding, which reduce the amounts available under the revolving credit facility. The credit agreement governing our senior secured revolving credit facility provides for interest-only payments until May 4, 2022, when the credit agreement matures (subject to a springing maturity date of June 15, 2020 if the 7.50% Senior Notes have not been refinanced on or prior to such time) and any outstanding borrowings are due.

Upon issuance of the 8.25% Senior Notes (described below), in accordance with the credit agreement governing the revolving credit facility, our borrowing base was reduced by 25% of the aggregate principal amount of the 8.25% Senior Notes, reducing the borrowing base from $900.0 million to $837.5 million. As a result of the Fall 2017 borrowing base redetermination, the borrowing base was established at $900.0 million, with an elected commitment amount of $800.0 million, until the next redetermination thereof. The calculation of the Fall 2017 borrowing base was supported solely by the reserves of our Eagle Ford and Delaware Basin assets. The borrowing base under our credit agreement is subject to regular redeterminations in the spring and fall of each year, as well as special redeterminations described in the credit agreement, which in each case may reduce the amount of the borrowing base.

On May 4, 2017, we entered into a ninth amendment to our credit agreement governing the revolving credit facility to, among other things, extend the maturity date, increase the maximum credit amount, and increase the borrowing base. On June 28, 2017, we entered into a tenth amendment to the credit agreement governing the revolving credit facility to, among other things, amend certain financial and restricted payments covenants as well as amend certain definitions. On November 3, 2017, we entered into an eleventh amendment to the credit agreement governing the revolving credit facility to, among other things establish the borrowing base at $900.0 million, with an elected commitment amount of $800.0 million, and increase the general basket available for restricted payments.

See "Note 6. Long-Term Debt" of the Notes to our Consolidated Financial Statements for additional details of the ninth, tenth and eleventh amendments, rates of interest on outstanding borrowings, commitment fees on the unused portion of lender commitments, and the financial covenants we are subject to under the terms of the credit agreement.

Preferred Stock Purchase Agreement

On June 28, 2017, we entered into a Preferred Stock Purchase Agreement with the GSO Funds to issue and sell in a private placement (i) $250.0 million (250,000 shares) of Preferred Stock and (ii) Warrants for 2,750,000 shares of our common stock, with a term of ten years and an exercise price of $16.08 per share, for a cash purchase price equal to $970.00 per share of Preferred Stock purchased. We paid the GSO Funds $5.0 million as a commitment fee upon signing the Preferred Stock Purchase Agreement. The closing of the private placement occurred on August 10, 2017 contemporaneously with the closing of the ExL Acquisition. We received net proceeds of approximately $236.4 million, net of issuance costs, from the issuance and sale of the Preferred Stock and Warrants, which were used to fund a portion of the purchase price of the ExL Acquisition. See “Note 3. Acquisitions and Divestitures of Oil and Gas Properties” of the Notes to our Consolidated Financial Statements for further details of the ExL Acquisition and “Note 9. Preferred Stock and Warrants” of the Notes to our Consolidated Financial Statements for further details regarding the Preferred Stock and Warrants.

Common Stock Offering

On July 3, 2017, we completed a public offering of 15.6 million shares of our common stock at a price per share of $14.28. We used the net proceeds of $222.4 million, net of offering costs, to fund a portion of the purchase price for the ExL Acquisition and for general corporate purposes.

8.25% Senior Notes due 2025

On July 14, 2017, we closed a public offering of $250.0 million aggregate principal amount of 8.25% Senior Notes due 2025. The 8.25% Senior Notes mature on July 15, 2025 and have interest payable semi-annually each January 15 and July 15. We used the net proceeds of $245.4 million, net of underwriting discounts and commissions and offering costs, to fund a portion of the purchase price for the ExL Acquisition and for general corporate purposes. See “Note 6. Long-Term Debt” of the Notes to our Consolidated Financial Statements for further details regarding the 8.25% Senior Notes.

7.50% Senior Notes due 2020

On November 28, 2017, we delivered a notice of redemption to the trustee for our 7.50% Senior Notes to call for redemption on December 28, 2017, $150.0 million aggregate principal amount of the 7.50% Senior Notes then outstanding. On December 28, 2017, we paid an aggregate redemption price of $156.0 million, which included a redemption premium of $2.8 million as well as accrued and unpaid interest of $3.2 million from the last interest payment date up to, but not including, the redemption date. As a result of the redemption, we recorded a loss on extinguishment of debt of $4.2 million, which includes the redemption premium paid to redeem the notes and non-cash charges of $1.3 million attributable to the write-off of unamortized premium and debt issuance costs associated with the 7.50% Senior Notes. See “Note 6. Long-Term Debt” of the Notes to our Consolidated Financial Statements for further details regarding the 7.50% Senior Notes. See “Note 15. Subsequent Events (Unaudited)” of the Notes to our Consolidated Financial Statements for details of the redemptions of our 7.50% Senior Notes that occurred subsequent to December 31, 2017.

Changes in Prices and Effects of Inflation

Our results of operations and operating cash flows are affected by changes in oil and gas prices. Natural gas prices have declined significantly since mid-2008 and continue to remain depressed. More recently, crude oil prices have declined significantly since 2014, which has adversely affected our results of operations. However crude oil prices have rebounded from the lowest prices in early 2016. If crude oil prices weaken from their current position, it is expected to have a significant impact on future results of operations and operating cash flows. Historically, inflation has had a minimal effect on us. However, with interest rates at historic lows and the government attempting to stimulate the economy through rapid expansion of the money supply in recent years, inflation could become a significant issue in the future.

Summary of Critical Accounting Policies

The following summarizes our critical accounting policies. See a complete list of significant accounting policies in “Note 2. Summary of Significant Accounting Policies” of the Notes to our Consolidated Financial Statements.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results. We evaluate subsequent events through the date the financial statements are issued.

Significant estimates include volumes of proved oil and gas reserves, which are used in calculating DD&A of proved oil and gas property costs, the present value of estimated future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and the estimated costs and timing of cash outflows underlying asset retirement obligations. Oil and gas reserve estimates, and therefore calculations based on such reserve estimates, are subject to numerous inherent uncertainties, the accuracy of which, is a function of the quality and quantity of available data, the application of engineering and geological interpretation and judgment to available data and the interpretation of mineral leaseholds and other contractual arrangements, including adequacy of title and drilling requirements. These estimates also depend on assumptions regarding quantities and production rates of recoverable oil and gas reserves, oil and gas prices, timing and amounts of development costs and operating expenses, all of which will vary from those assumed in our estimates. Other significant estimates are involved in determining acquisition date fair values of assets acquired and liabilities assumed, impairments of unevaluated leasehold costs, fair values of derivative assets and liabilities, fair values of contingent consideration, preferred stock fair value upon issuance, grant date fair value of stock-based awards, and evaluating disputed claims, interpreting contractual arrangements and contingencies. Estimates are based on current assumptions that may be materially affected by the results of subsequent drilling and completion, testing and production as well as subsequent changes in oil and gas prices, interest rates and the market value and volatility of our common stock.

Oil and Gas Properties

Oil and gas properties are accounted for using the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities are capitalized to cost centers established on a country-by-country basis. The internal cost of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities are capitalized to either proved or unproved oil and gas properties based on the type of activity and totaled $14.8 million, $10.5 million and $15.8 million for the years ended December 31, 2017, 2016 and 2015, respectively. Internal costs related to production, general corporate overhead and similar activities are expensed as incurred.

Capitalized oil and gas property costs within a cost center are amortized on an equivalent unit-of-production method, converting natural gas to barrels of oil equivalent at the ratio of six thousand cubic feet of gas to one barrel of oil, which represents their approximate relative energy content. The equivalent unit-of-production amortization rate is computed on a quarterly basis by dividing current quarter production by proved oil and gas reserves at the beginning of the quarter then applying such amortization rate to proved oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values. Average DD&A per Boe of proved oil and gas properties was $13.09, $13.50 and $22.05 for the years ended December 31, 2017, 2016 and 2015, respectively.

Unproved properties, not being amortized, include unevaluated leasehold and seismic costs associated with specific unevaluated properties and related capitalized interest. Individually significant unevaluated leaseholds are assessed on a quarterly basis to determine whether or not and to what extent proved reserves have been assigned to the properties or if an impairment has occurred, in which case the related costs along with associated capitalized interest are reclassified to proved oil and gas properties. Factors we consider in our impairment assessment include drilling results by us and other operators, the terms of oil and gas leases not held by production and drilling, completion, and infrastructure capital expenditure plans. Individually insignificant unevaluated leaseholds are grouped by major area and added to proved oil and gas properties based on the average primary lease term of the properties. Geological and geophysical costs not associated with specific prospects are recorded to proved oil and gas property costs as incurred. We capitalized interest costs to unproved properties totaling $28.3 million, $17.0 million and $32.1 million for the years ended December 31, 2017, 2016 and 2015, respectively. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unproved properties and the weighted average interest rate of outstanding borrowings.

Proceeds from the sale of proved and unproved oil and gas properties are recognized as a reduction of proved oil and gas property costs with no gain or loss recognized, unless the sale significantly alters the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For the years ended December 31, 2017, 2016 and 2015, we did not have any sales of oil and gas properties that significantly altered such relationship.

Impairment of Proved Oil and Gas Properties

At the end of each quarter, the net book value of oil and gas properties, less related deferred income taxes, are limited to the "cost center ceiling" equal to (i) the sum of (a) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (b) the costs of unproved properties not being amortized, and (c) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and gas properties, less related deferred income taxes, over the cost center ceiling is recognized as an impairment of proved oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher commodity prices in the future result in a cost center ceiling in excess of the net book value of oil and gas properties, less related deferred income taxes.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of crude oil, NGLs, and natural gas on the first calendar day of each month during the 12-month period prior to the end of the current quarter ("12-Month Average Realized Price"), held flat for the life of the production, except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of derivative instruments as we elected not to meet the criteria to qualify derivative instruments for hedge accounting treatment.

We did not recognize impairments of proved oil and gas properties for the year ended December 31, 2017. Primarily due to declines in the 12-Month Average Realized Prices of crude oil, we recognized impairments of proved oil and gas properties for the years ended December 31, 2016 and 2015. Details of the 12-Month Average Realized Price of crude oil for the years ended December 31, 2017, 2016 and 2015 and the impairments of proved oil and gas properties for the years ended December 31, 2016 and 2015 are summarized in the table below:

	Years Ended December 31,		
	2017	**2016**	**2015**
Impairment of proved oil and gas properties (in thousands)	$—	$576,540	$1,224,367
Crude Oil 12-Month Average Realized Price ($/Bbl) - Beginning of period	$39.60	$47.24	$92.24
Crude Oil 12-Month Average Realized Price ($/Bbl) - End of period	$49.87	$39.60	$47.24
Crude Oil 12-Month Average Realized Price percentage increase (decrease) during period	26%	(16%)	(49%)

The table below presents various pricing scenarios to demonstrate the sensitivity of our December 31, 2017 cost center ceiling to changes in 12-month average benchmark crude oil and natural gas prices underlying the 12-Month Average Realized Prices. The sensitivity analysis is as of December 31, 2017 and, accordingly, does not consider drilling and completion activity, acquisitions or dispositions of oil and gas properties, production, changes in crude oil and natural gas prices, and changes in development and operating costs occurring subsequent to December 31, 2017 that may require revisions to estimates of proved reserves. See also Part I, "Item 1A. Risk Factors—If crude oil and natural gas prices decline to near or below levels experienced in 2015 and 2016 we could be required to record additional impairments of proved oil and gas properties that would constitute a charge to earnings and reduce our shareholders' equity."

	12-Month Average Realized Prices		**Excess (deficit) of cost center ceiling over net book value, less related deferred income taxes**	**Increase (decrease) of cost center ceiling over net book value, less related deferred income taxes**
Full Cost Pool Scenarios	**Crude Oil ($/Bbl)**	**Natural Gas ($/Mcf)**	**(In millions)**	**(In millions)**
December 31, 2017 Actual	$49.87	$2.96	$677	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$55.00	$3.27	$1,212	$535
Crude Oil and Natural Gas -10%	$44.74	$2.65	$149	($528)
Crude Oil Price Sensitivity				
Crude Oil +10%	$55.00	$2.96	$1,164	$487
Crude Oil -10%	$44.74	$2.96	$196	($481)
Natural Gas Price Sensitivity				
Natural Gas +10%	$49.87	$3.27	$725	$48
Natural Gas -10%	$49.87	$2.65	$630	($47)

Oil and Gas Reserve Estimates

The proved oil and gas reserve estimates as of December 31, 2017 included in this document have been prepared by Ryder Scott Company, L.P., ("Ryder Scott"), independent third party reserve engineers. Reserve engineering is a subjective process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact manner. The process relies on judgment and the interpretation of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires assumptions regarding drilling and operating costs, taxes and availability of funds. The oil and gas reserve estimation and disclosure requirements mandate certain of these assumptions such as existing economic and operating conditions, average crude oil and natural gas prices and the discount rate.

Proved oil and gas reserve estimates prepared by others may be substantially higher or lower than Ryder Scott's estimates. Significant assumptions used in the proved oil and gas reserve estimates are assessed by both Ryder Scott and our internal reserve team. All reserve reports prepared by Ryder Scott are reviewed by our senior management team, including the Chief Executive Officer and Chief Operating Officer. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve quantities actually recovered may be significantly different than estimated. Material revisions to reserve estimates may be made depending on the results of drilling, testing, and production.

It should not be assumed that the present value of future net cash flows is the current market value of our estimated proved oil and gas reserves. In accordance with the oil and gas reserve estimation and disclosure requirements, the discounted future net cash flows from proved reserves are based on the unweighted average of the first day of the month price for each month in the previous twelve-month period, using current costs and a 10% discount rate.

Our depletion rate depends on our estimate of total proved reserves. If our estimates of total proved reserves increased or decreased, the depletion rate and therefore DD&A expense of proved oil and gas properties would decrease or increase, respectively.

Derivative Instruments

We use commodity derivative instruments to reduce our exposure to commodity price volatility for a portion of our forecasted crude oil, NGL, and natural gas production and thereby achieve a more predictable level of cash flows to support our drilling, completion, and infrastructure capital expenditure program. All derivative instruments are recorded in the consolidated balance sheets as either an asset or liability measured at fair value. We net our commodity derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. As we have elected not to meet the criteria to qualify our derivative instruments for hedge accounting treatment, gains and losses as a result of changes in the fair value of commodity derivative instruments are recognized as (gain) loss on derivatives, net in the consolidated statements of operations in the period in which the changes occur. The net cash flows resulting from the payments to and receipts from counterparties as a result of derivative settlements are classified as cash flows from operating activities. We do not enter into derivative instruments for speculative or trading purposes.

Our Board of Directors establishes risk management policies and, on a quarterly basis, reviews its commodity derivative instruments, including volumes, types of instruments and counterparties. These policies require that commodity derivative instruments be executed only by the President or Chief Financial Officer after consultation with and concurrence by the President, Chief Financial Officer and Chairman of the Board.

We have entered into agreements for acquisitions and divestitures of oil and gas properties that include obligations to pay the seller or rights to receive from the buyer, respectively, additional consideration if commodity prices exceed certain thresholds during certain specified periods in the future. These contingent consideration liabilities and assets are required to be bifurcated and accounted for separately as derivative instruments as they are not considered to be clearly and closely related to the host contract, and recognized at their acquisition or divestiture date fair value in the consolidated balance sheet, with subsequent changes in fair value recognized as (gain) loss on derivatives, net in the consolidated statements of operations in the period in which the changes occur. Cash payments made to settle contingent consideration liabilities are classified as cash flows from financing activities up to the acquisition date fair value with any excess classified as cash flows from operating activities.

Preferred Stock and Warrants

We apply the accounting standards for distinguishing liabilities from equity when determining the classification and measurement of preferred stock. Preferred stock that is not mandatorily redeemable is excluded from liability classification and is evaluated for classification in shareholders' equity or temporary equity. As the number of common shares that could be delivered upon the holders' optional redemption is indeterminate, we cannot assert that we will be able to settle in shares of our common stock and, as a result, presents preferred stock as temporary equity. On a quarterly basis, we reassess the presentation of preferred stock in the consolidated balance sheets.

When preferred stock is issued in conjunction with warrants, the warrants are evaluated separately as a freestanding financial instrument to determine whether they must be recorded as a derivative instrument. We further evaluate the warrants for equity classification and have determined that the warrants qualify for equity classification and, therefore, are presented in additional paid-in capital in the consolidated balance sheets. The preferred stock and warrants are recorded based on the net proceeds received allocated to the two instrument's relative fair values. The preferred stock is subject to accretion from its relative fair value at the issuance date to the redemption value using the effective interest method. The warrants do not require further adjustments from their relative fair value at the issuance date.

Dividends and accretion associated with preferred stock are presented in the consolidated statements of operations as reductions to net income, or increases of net loss, to derive net income (loss) attributable to common shareholders. Dividend payments are presented as a financing activity in the consolidated statement of cash flows.

Income Taxes

Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are recognized at the end of each reporting period for the future tax consequences of cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in our financial statements based on existing tax laws and enacted statutory tax rates applicable to the periods in which the temporary differences are expected to affect taxable income. As a result of the 2017 Tax Cuts and Jobs Act that was enacted on December 22, 2017, the federal statutory corporate income tax rate was reduced from 35% to 21% effective January 1, 2018. The deferred tax assets and liabilities at December 31, 2017 were re-measured taking into account the new enacted federal statutory corporate income tax rate for which those deferred tax balances were expected to be realized. See "Note 5. Income Taxes" of the Notes to our Consolidated Financial Statements for further discussion. We assess the realizability of our deferred tax assets on a quarterly basis by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. We consider all available evidence (both positive and negative) when determining whether a valuation allowance is required. In making this assessment, we evaluated possible sources of taxable income that may be available to realize the deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies.

A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at December 31, 2017, driven primarily by the impairments of proved oil and gas properties beginning in the third quarter of 2015 and continuing through the third quarter of 2016, which limits the ability to consider other subjective evidence such as our potential for future growth. We also have estimated U.S. federal net operating loss carryforwards of $1,096.2 million as of December 31, 2017. Beginning in the third quarter of 2015, and continuing through the fourth quarter of 2017, we concluded that it was more likely than not the deferred tax assets will not be realized. As a result, the net deferred tax assets at the end of each quarter, including December 31, 2017, were reduced to zero.

As a result of adopting ASU 2016-09, we recognized previously unrecognized windfall tax benefits which resulted in a cumulative-effect adjustment to retained earnings of approximately $15.7 million. This adjustment increased deferred tax assets, which in turn increased the valuation allowance by the same amount as of the beginning of 2017, resulting in a net cumulative-effect adjustment to retained earnings of zero and brought the valuation allowance to $580.1 million as of January 1, 2017.

During the year ended December 31, 2017, the valuation allowance was reduced by $247.1 million. This was primarily due to the re-measurement of our deferred tax assets as a result of the Tax Cuts and Jobs Act as mentioned above, which resulted in a reduction of $211.7 million, as well as partial releases of $35.4 million, as a result of current year activity. After the impact of the re-measurement and the partial releases, the valuation allowance as of December 31, 2017 was $333.0 million.

We will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until we can conclude that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead us to conclude that it is more likely than not its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not preclude us from utilizing the tax attributes if we recognize taxable income.

We classify interest and penalties associated with income taxes as interest expense. We apply the tax law ordering approach to determine the sequence in which deferred tax assets and other tax attributes are utilized.

Commitments and Contingencies

Liabilities are recognized for contingencies when (i) it is both probable that an asset has been impaired or that a liability has been incurred and (ii) the amount of such loss is reasonably estimable. See "Note 8. Commitments and Contingencies" of the Notes to our Consolidated Financial Statements for further detail.

Recent Accounting Pronouncements

See "Note 2. Summary of Significant Accounting Policies - Recent Accounting Pronouncements" of the Notes to our Consolidated Financial Statements for discussion of the recent accounting pronouncements issued by the Financial Accounting Standards Board.

Volatility of Crude Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial position and ability to borrow funds or obtain additional capital are substantially dependent upon prevailing prices of crude oil, which are affected by changes in market supply and demand, overall economic activity, global political environment, weather, inventory storage levels and other factors, as well as the level and prices at which we have hedged our future production.

We review the carrying value of our oil and gas properties on a quarterly basis under the full cost method of accounting. See "—Summary of Critical Accounting Policies—Impairment of Proved Oil and Gas Properties." See also Part I, "Item 1A. Risk Factors—If crude oil and natural gas prices decline to near or below the low levels experienced in 2015 and 2016 we could be required to record additional impairments of proved oil and gas properties that would constitute a charge to earnings and reduce our shareholders' equity" and "Note 4. Property and Equipment, Net" of the Notes to our Consolidated Financial Statements.

We use commodity derivative instruments to reduce our exposure to commodity price volatility for a portion of our forecasted production and thereby achieve a more predictable level of cash flows to support our drilling, completion, and infrastructure capital expenditure program. We do not enter into derivative instruments for speculative or trading purposes. As of December 31, 2017, our commodity derivative instruments consisted of fixed price swaps, basis swaps, three-way collars and purchased and sold call options. See "Note 11. Derivative Instruments" of the Notes to our Consolidated Financial Statements for further details of our crude oil, NGL, and natural gas derivative positions as of December 31, 2017 and "Note 15. Subsequent Events (Unaudited)" of the Notes to our Consolidated Financial Statements for further details of our natural gas derivative positions entered into subsequent to December 31, 2017.

We determined that the Contingent ExL Consideration, the Contingent Utica Consideration, and the Contingent Marcellus Consideration are not clearly and closely related to the purchase and sale agreement for the applicable acquisition or divestiture, and therefore bifurcated these embedded features and reflected the associated assets and liabilities at fair value in the consolidated financial statements. The fair values of the contingent consideration were determined by a third-party valuation specialist using Monte Carlo simulations including significant inputs such as future commodity prices, volatility factors for the future commodity prices and a risk adjusted discount rate. See "Note 11. Derivative Instruments" and "Note 12. Fair Value Measurements" of the Notes to our Consolidated Financial Statements for further details.

Item 7A. Qualitative and Quantitative Disclosures about Market Risk

Commodity Risk

Our primary market risk exposure is the commodity pricing applicable to our oil and gas production. The prices we realize on the sale of such production are primarily driven by the prevailing worldwide price for oil and spot prices of natural gas. The effects of such pricing volatility have been discussed above, and such volatility is expected to continue. A 10% fluctuation in the price received for oil production, excluding the impact of derivative settlements, would have an approximate $63.3 million impact on our revenues and a 10% fluctuation in the price received for gas production, excluding the impact of derivative settlements, would have an approximate $6.5 million impact on our revenues for the year ended December 31, 2017.

We use commodity derivative instruments to reduce our exposure to commodity price volatility for a portion of our forecasted crude oil, NGL, and natural gas production and thereby achieve a more predictable level of cash flows to support our drilling, completion and infrastructure capital expenditure program. We do not enter into derivative instruments for speculative or trading purposes. As of December 31, 2017, our commodity derivative instruments consisted of fixed price swaps, basis swaps, three-way collars and purchased and sold call options. For the years ended December 31, 2017, 2016 and 2015, we recorded in the consolidated statements of operations a loss on derivatives, net of $59.1 million and $49.1 million and a gain on derivatives, net of $99.3 million, respectively. We also received net cash on derivative settlements of $7.8 million, $119.4 million and $194.3 million for the years ended December 31, 2017, 2016 and 2015, respectively, which are presented in the consolidated statements of cash flows.

We have entered into agreements for the acquisition and divestiture of oil and gas properties containing contingent consideration that are, or will be, required to be bifurcated and accounted for separately as derivative instruments as they are not clearly and closely related to the host contract. We record the contingent consideration in the consolidated balance sheets measured at acquisition or divestiture date fair value, with gains and losses as a result of changes in the fair value of the contingent consideration recognized as (gain) loss on derivatives, net in the consolidated statements of operations in the period in which the changes occur.

The following table sets forth the fair values as of December 31, 2017 as well as the impact on the fair values assuming a 10% increase and a 10% decrease in the respective commodity prices:

	Contingent ExL Consideration	Contingent Utica Consideration	Contingent Marcellus Consideration
		(In thousands)	
Potential (payment) receipt per year	($50,000)	$5,000	$3,000
Maximum potential (payment) receipt	($125,000)	$15,000	$7,500
Fair value as of December 31, 2017	($85,625)	$7,985	$2,205
10% increase in commodity price	(96,610)	9,405	3,050
10% decrease in commodity price	(65,765)	5,725	1,450

Financial Instruments and Debt Maturities

In addition to our derivative instruments, our other financial instruments consist of cash and cash equivalents, receivables, payables, and long-term debt. The carrying amounts of cash and cash equivalents, receivables, and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of our 7.50% Senior Notes, 6.25% Senior Notes, 8.25% Senior Notes and other long-term debt as of December 31, 2017 were estimated at approximately $459.5 million,

$674.4 million, $274.4 million and $4.4 million, respectively, and were based on quoted market prices. As of December 31, 2017, scheduled maturities of debt are $450.0 million in 2020, $650.0 million in 2023, $250.0 million in 2025 and $4.4 million in 2028. We had $291.3 million of borrowings outstanding under our revolving credit facility as of December 31, 2017.

Item 8. Financial Statements and Supplementary Data

The financial statements and information required by this Item appears on pages F-1 through F-47 of this Annual Report on Form 10-K.

Item 9. Changes In and Disagreements With Accountants on Accounting and Financial Disclosures

None.

Item 9A. Controls and Procedures

(a) Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

In accordance with Rules 13a-15(b) and 15d-15(b) under the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. As described below under paragraph (b) within Management's Annual Report on Internal Control over Financial Reporting, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this Annual Report on Form 10-K, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

The audit report of Ernst & Young LLP which is included in this Annual Report on Form 10-K, expressed an unqualified opinion on our consolidated financial statements.

(b) Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

While "reasonable assurance" is a high level of assurance, it does not mean absolute assurance. Because of its inherent limitations, internal control over financial reporting may not prevent or detect every misstatement and instance of fraud. Controls are susceptible to manipulation, especially in instances of fraud caused by collusion of two or more people, including our senior management. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, our management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017. In making this evaluation, management used the *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring

Organizations of the Treadway Commission ("COSO"). Based on the results of our evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2017.

Ernst & Young LLP, our independent registered public accounting firm that audited our consolidated financial statements, has also issued its own audit report on the effectiveness of our internal control over financial reporting as of December 31, 2017, which is filed with this Annual Report on Form 10-K.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to our definitive Proxy Statement (the "2018 Proxy Statement") for our 2018 annual meeting of shareholders to be held on May 22, 2018. The 2018 Proxy Statement will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2018 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2017.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a)(1) Financial Statements

Refer to the Index to Consolidated Financial Statements on page F-1 of this Form 10-K for a list of all financial statements filed as part of this report.

(a)(2) Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Company's consolidated financial statements and related notes.

(a)(3) Exhibits

EXHIBIT INDEX

Exhibit Number		Description
†+2.1	—	Purchase and Sale Agreement dated as of June 28, 2017 by and among ExL Petroleum Management, LLC, ExL Petroleum Operating Inc., Carrizo Oil & Gas, Inc., and Carrizo (Permian) LLC (incorporated herein by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed June 28, 2017 (File No. 000-29187-87)).
+2.2	—	Purchase and Sale Agreement dated December 9, 2017 between Carrizo Oil & Gas, Inc., Carrizo (Eagle Ford) LLC, and EP Energy E&P Company, L.P., as amended by that certain Closing Agreement and Amendment to Purchase and Sale Agreement dated as of January 31, 2018 between the parties thereto.
†3.1	—	Amended and Restated Articles of Incorporation of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997 (File No. 000-29187-87)).
†3.2	—	Articles of Amendment to Amended and Restated Articles of Incorporation of Carrizo Oil & Gas, Inc. dated as of June 24, 2008 (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on June 25, 2008 (File No. 000-29187-87)).
†3.3	—	Articles of Amendment to Amended and Restated Articles of Incorporation of Carrizo Oil & Gas, Inc. dated as of May 16, 2017 (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on May 16, 2017 (File No. 000-29187087)).
†3.4	—	Composite Articles of Incorporation of Carrizo Oil & Gas, Inc., giving effect to all amendments through May 16, 2017 (incorporated herein by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on May 16, 2017 (File No. 000-29187087)).
†3.5	—	Statement of Resolutions Establishing Series of 8.875% Redeemable Preferred Stock of Carrizo Oil & Gas, Inc., effective August 10, 2017 (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on August 11, 2017 (File No. 000-29187087)).
†3.6	—	Amended and Restated Bylaws of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on February 19, 2015 (File No. 000-29187-87)).
†4.1	—	Indenture dated May 28, 2008 among Carrizo Oil & Gas, Inc., the subsidiaries named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on May 28, 2008 (File No. 000-29187-87)).
†4.2	—	First Supplemental Indenture dated May 28, 2008 between Carrizo Oil & Gas, Inc. and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on May 28, 2008 (File No. 000-29187-87)).
†4.3	—	Second Supplemental Indenture dated May 14, 2009 among Carrizo Oil & Gas, Inc., the subsidiaries named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.21 to the Company's Registration Statement on Form S-3 (Registration No. 333-159237)).
†4.4	—	Third Supplemental Indenture dated October 19, 2009 among Carrizo Oil & Gas, Inc., the subsidiary named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.19 to the Company's Registration Statement on Form S-3 (Registration No. 333-159237)).
†4.5	—	Fourth Supplemental Indenture dated November 2, 2010 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on November 2, 2010 (File No. 000-29187-87)).
†4.6	—	Fifth Supplemental Indenture dated November 2, 2010 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on November 2, 2010 (File No. 000-29187-87)).
†4.7	—	Sixth Supplemental Indenture dated May 4, 2011 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 000-29187-87)).

†4.8	—	Seventh Supplemental Indenture dated May 4, 2011 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 000-29187-87)).
†4.9	—	Eighth Supplemental Indenture dated August 5, 2011 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 (File No. 000-29187-87)).
†4.10	—	Ninth Supplemental Indenture dated August 5, 2011 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 (File No. 000-29187-87)).
†4.11	—	Tenth Supplemental Indenture among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee, dated as of September 10, 2012 (incorporated herein by reference to Exhibit 4.2 to the Company Current Report on Form 8-K filed on September 13, 2012 (File No. 000-29187-87)).
†4.12	—	Eleventh Supplemental Indenture dated November 6, 2012 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 (File No. 000-29187-87)).
†4.13	—	Twelfth Supplemental Indenture dated November 6, 2012 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 (File No. 000-29187-87)).
†4.14	—	Thirteenth Supplemental Indenture dated November 6, 2012 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 (File No. 000-29187-87)).
†4.15	—	Fourteenth Supplemental Indenture dated November 6, 2012 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 (File No. 000-29187-87)).
†4.16	—	Fifteenth Supplemental Indenture dated October 30, 2014 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on October 30, 2014 (File No. 000-29187-87)).
†4.17	—	Sixteenth Supplemental Indenture dated April 28, 2015 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on April 28, 2015 (File No. 000-29187-87)).
†4.18	—	Seventeenth Supplemental Indenture dated May 20, 2015 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on May 22, 2015 (File No. 000-29187-87)).
†4.19	—	Eighteenth Supplemental Indenture dated May 20, 2015 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on May 22, 2015 (File No. 000-29187-87)).
†4.20	—	Nineteenth Supplemental Indenture dated May 20, 2015 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on May 22, 2015 (File No. 000-29187-87)).
†4.21	—	Twentieth Supplemental Indenture dated July 14, 2017 among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed on July 14, 2017 (File No. 000-29187-87)).

†4.22	—	Officers' Certificate of Carrizo Oil & Gas, Inc. dated as of November 17, 2011 (incorporated herein by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K filed on November 17, 2011 (File No. 000-29187-87)).
†4.23	—	Officers' Certificate of Carrizo Oil & Gas, Inc. dated as of February 23, 2015 (incorporated herein by reference to Exhibit 4.17 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 000-29187-87)).
†4.24	—	Warrant Agreement, dated as of August 10, 2017, between Carrizo Oil & Gas, Inc. and Wells Fargo Bank, N.A., as warrant agent (incorporated herein by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on August 11, 2017 (File No. 000-29187087)).
*†10.1	—	Amended and Restated Incentive Plan of Carrizo Oil & Gas, Inc. effective as of May 15, 2014 (the "2014 Incentive Plan") (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 16, 2014 (File No. 000-29187-87)).
*†10.2	—	2017 Incentive Plan of Carrizo Oil & Gas, Inc. effective as of May 16, 2017 (the "2017 Incentive Plan") (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 16, 2017 (File No. 000-29187087)).
*†10.3	—	Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan (incorporated herein by reference to Exhibit 10.10 to the Company's Current Report on Form 8-K filed on June 9, 2009 (File No. 000-29187-87)).
*†10.4	—	Form of Employment Agreement between Carrizo Oil & Gas, Inc. and future executive officers as of May 1, 2015 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly report on Form 10-Q for the quarter ended March 31, 2015 (File No. 000-29187-87)).
*†10.5	—	Form of Employment Agreement between Carrizo Oil & Gas, Inc. and future non-executive officers as of May 1, 2015 (incorporated by reference to Exhibit 10.3 to the Company's Quarterly report on Form 10-Q for the quarter ended March 31, 2015 (File No. 000-29187-87)).
*†10.6	—	Amended and Restated Employment Agreement between the Company and S.P. Johnson IV (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on June 9, 2009 (File No. 000-29187-87)).
*†10.7	—	Amended and Restated Employment Agreement between the Company and J. Bradley Fisher (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on June 9, 2009 (File No. 000-29187-87)).
*†10.8	—	Amended and Restated Employment Agreement between the Company and Richard H. Smith (incorporated herein by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on June 9, 2009 (File No. 000-29187-87)).
*†10.9	—	Employment Agreement between the Company and David L. Pitts (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 20, 2010 (File No. 000-29187-87)).
*†10.10	—	Employment Agreement between the Company and Gregory F. Conaway (incorporated herein by reference to Exhibit 10.10 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 100-29187-87)).
*†10.11	—	Employment Agreement between the Company and Gerald A. Morton (incorporated herein by reference to Exhibit 10.11 to the Company's Annual Report on Form 10-K for the year ended December 31, 2015 (File No. 100-29187-87)).
*†10.12	—	Form of Employee Restricted Stock Award Agreement (Officer) under the 2014 Incentive Plan (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on June 17, 2013 (File No. 000-29187-87)).
*†10.13	—	Form of Employee Restricted Stock Unit Award Agreement (Officer) under the 2014 Incentive Plan (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on June 17, 2013 (File No. 000-29187-87)).
*†10.14	—	Form of Employee Performance Share Award Agreement under the 2014 Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 (File No. 000-29187-87)).
*†10.15	—	Form of Employee Stock Appreciation Rights Agreement (Officer) under the 2014 Incentive Plan (incorporated herein by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on June 17, 2013 (File No. 000-29187-87)).

*†10.16	—	Form of Employee Stock Appreciation Rights Agreement (Officer) under the Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan (incorporated herein by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on June 17, 2013 (File No. 000-29187-87)).
*†10.17	—	Form of Director Restricted Stock Unit Agreement under the 2017 Incentive Plan (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on May 16, 2017 (File No. 000-29187-87)).
*†10.18	—	Form of Employee Restricted Stock Unit Agreement under the 2017 Incentive Plan (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on May 16, 2017 (File No. 000-29187-87)).
*10.19	—	Form of Employee Restricted Stock Agreement under the 2017 Incentive Plan.
*10.20	—	Form of Employee Performance Share Award Agreement (Officer) under the 2017 Incentive Plan.
*10.21	—	Form of Employee Stock Appreciation Rights Agreement (Officer) under the 2017 Incentive Plan.
*10.22	—	Form of Employee Stock Appreciation Rights Agreement (Officer) under the Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan.
†10.23	—	Credit Agreement dated as of January 27, 2011 among Carrizo Oil & Gas, Inc., as Borrower, BNP Paribas, as Administrative Agent, Credit Agricole Corporate and Investment Bank and Royal Bank of Canada, as Co-Syndication Agents, Capital One, N.A. and Compass Bank, as Co-Documentation Agents, BNP Paribas Securities Corp. as Sole Lead Arranger and Sole Bookrunner, and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 2, 2011 (File No. 000-29187-87)).
†10.24	—	First Amendment, dated as of March 26, 2012, to Credit Agreement dated as of January 27, 2011, among Carrizo Oil & Gas, Inc., BNP Paribas as administrative agent, and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 (File No. 000-29187-87)).
†10.25	—	Second Amendment to Credit Agreement, dated as of September 4, 2012, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 5, 2012 (File No. 000-29187-87)).
†10.26	—	Third Amendment to Credit Agreement, dated as of September 27, 2012, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 (File No. 000-29187-87)).
†10.27	—	Fourth Amendment to Credit Agreement, dated as of October 9, 2013, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 11, 2013 (File No. 000-29187-87)).
†10.28	—	Fifth Amendment to Credit Agreement, dated as of October 7, 2014, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 9, 2014 (File No. 000-29187-87)).
†10.29	—	Sixth Amendment to Credit Agreement, dated as of May 5, 2015, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 (File No. 000-29187-87)).
†10.30	—	Seventh Amendment to Credit Agreement, dated as of October 30, 2015, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015 (File No. 000-29187-87)).
†10.31	—	Eighth Amendment to Credit Agreement, dated as of May 3, 2016, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 4, 2016 (File No. 000-29187-87)).

†10.32	—	Ninth Amendment to Credit Agreement, dated as of May 4, 2017, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 10-Q filed on May 9, 2017 (File No. 000-29187-87)).
†10.33	—	Tenth Amendment to Credit Agreement, dated as of June 28, 2017, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 28, 2017 (File No. 000-29187087)).
†10.34	—	Eleventh Amendment to Credit Agreement, dated as of November 3, 2017, among Carrizo Oil & Gas, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lender parties thereto (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 10-Q filed on November 9, 2017 (File No. 000-29187087)).
†10.35	—	Form of Indemnification Agreement between the Company and each of its directors and executive officers (incorporated herein by reference to Exhibit 10.6 to the Company's Annual Report on Form 10-K for the year ended December 31, 1997 (File No. 000-29187-87)).
†10.36	—	Form of Amendment to Director Indemnification Agreement (incorporated herein by reference to Exhibit 99.8 to the Company's Current Report a Form 8-K filed February 27, 2002 (File No. 000-29187-87)).
†10.37	—	Preferred Stock Purchase Agreement dated as of June 28, 2017 between Carrizo Oil & Gas, Inc. and the purchasers named therein (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 28, 2017 (File No. 000-29187087)).
†10.38	—	Registration Rights Agreement dated as of August 10, 2017 between Carrizo Oil & Gas, Inc. and the GSO Funds party thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on August 11, 2017 (File No. 000-29187087)).
†10.39	—	Standstill and Voting Agreement dated as of August 10, 2017 between Carrizo Oil & Gas, Inc. and the GSO Funds party thereto (incorporated herein by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on August 11, 2017 (File No. 000-29187087)).
21.1	—	Subsidiaries of the Company.
23.1	—	Consent of Ernst & Young LLP.
23.2	—	Consent of KPMG LLP.
23.3	—	Consent of Ryder Scott Company, L.P.
31.1	—	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	—	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	—	CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	—	CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	—	Summary of Reserve Report and Report of Ryder Scott Company, L.P. as of December 31, 2017.
101	—	Interactive Data Files.

† Incorporated by reference as indicated.
* Management contract or compensatory plan or arrangement.
+ Schedules to this exhibit have been omitted pursuant to Item 601(b) of Regulation S-K; a copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Carrizo Oil & Gas, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Carrizo Oil & Gas, Inc. (the Company) as of December 31, 2017, and the related consolidated statements of operations, shareholders' equity and cash flows for the year then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2017, and the results of its operations and its cash flows for the year then ended 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, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 28, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audit. 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 audit 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 financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the 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 financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2017.

Houston, Texas
February 28, 2018

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Carrizo Oil & Gas, Inc.

Opinion on Internal Control over Financial Reporting

We have audited Carrizo Oil & Gas, Inc.'s internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Carrizo Oil & Gas, Inc. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet as of December 31, 2017, and the related consolidated statements of operations, shareholders' equity and cash flows for the year then ended, and the related notes and our report dated February 28, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Houston, Texas
February 28, 2018

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Carrizo Oil & Gas, Inc.:

We have audited the accompanying consolidated balance sheet of Carrizo Oil & Gas, Inc. and subsidiaries (the Company) as of December 31, 2016, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the two‑year period ended December 31, 2016. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Carrizo Oil & Gas, Inc. and subsidiaries as of December 31, 2016, and the results of their operations and their cash flows for each of the years in the two‑year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas
February 27, 2017

CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

	December 31, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$9,540	$4,194
Accounts receivable, net	107,441	64,208
Other current assets	5,897	4,586
Total current assets	122,878	72,988
Property and equipment		
Oil and gas properties, full cost method		
Proved properties, net	1,965,347	1,294,667
Unproved properties, not being amortized	660,287	240,961
Other property and equipment, net	10,176	10,132
Total property and equipment, net	2,635,810	1,545,760
Other assets	19,616	7,579
Total Assets	$2,778,304	$1,626,327
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable	$74,558	$55,631
Revenues and royalties payable	52,154	38,107
Accrued capital expenditures	119,452	36,594
Accrued interest	28,362	22,016
Accrued lease operating expense	18,223	12,377
Derivative liabilities	57,121	22,601
Other current liabilities	22,952	24,633
Total current liabilities	372,822	211,959
Long-term debt	1,629,209	1,325,418
Asset retirement obligations	23,497	20,848
Derivative liabilities	112,332	27,528
Deferred income taxes	3,635	—
Other liabilities	51,650	17,116
Total liabilities	2,193,145	1,602,869
Commitments and contingencies		
Preferred Stock		
Preferred stock, $0.01 par value, 10,000,000 shares authorized; 250,000 issued and outstanding as of December 31, 2017 and none issued and outstanding as of December 31, 2016	214,262	—
Shareholders' equity		
Common stock, $0.01 par value, 180,000,000 shares authorized; 81,454,621 issued and outstanding as of December 31, 2017 and 90,000,000 shares authorized; 65,132,499 issued and outstanding as of December 31, 2016	815	651
Additional paid-in capital	1,926,056	1,665,891
Accumulated deficit	(1,555,974)	(1,643,084)
Total shareholders' equity	370,897	23,458
Total Liabilities and Shareholders' Equity	$2,778,304	$1,626,327

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	Years Ended December 31,		
	2017	2016	2015
Revenues			
Crude oil	$633,233	$378,073	$376,094
Natural gas liquids	47,405	22,428	15,608
Natural gas	65,250	43,093	37,501
Total revenues	745,888	443,594	429,203
Costs and Expenses			
Lease operating	139,854	98,717	90,052
Production taxes	32,509	19,046	17,683
Ad valorem taxes	7,267	5,559	9,255
Depreciation, depletion and amortization	262,589	213,962	300,035
General and administrative, net	66,229	74,972	67,224
(Gain) loss on derivatives, net	59,103	49,073	(99,261)
Interest expense, net	80,870	79,403	69,195
Impairment of proved oil and gas properties	—	576,540	1,224,367
Loss on extinguishment of debt	4,170	—	38,137
Other expense, net	2,157	1,796	11,276
Total costs and expenses	654,748	1,119,068	1,727,963
Income (Loss) From Continuing Operations Before Income Taxes	91,140	(675,474)	(1,298,760)
Income tax (expense) benefit	(4,030)	—	140,875
Income (Loss) From Continuing Operations	$87,110	($675,474)	($1,157,885)
Income From Discontinued Operations, Net of Income Taxes	—	—	2,731
Net Income (Loss)	$87,110	($675,474)	($1,155,154)
Dividends on preferred stock	(7,781)	—	—
Accretion on preferred stock	(862)	—	—
Net Income (Loss) Attributable to Common Shareholders	$78,467	($675,474)	($1,155,154)
Net Income (Loss) Attributable to Common Shareholders Per Common Share			
Basic	$1.07	($11.27)	($22.45)
Diluted	$1.06	($11.27)	($22.45)
Weighted Average Common Shares Outstanding			
Basic	73,421	59,932	51,457
Diluted	73,993	59,932	51,457

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(In thousands, except share amounts)

	Common Stock		Additional Paid-in Capital	Accumulated Deficit	Total Shareholders' Equity
	Shares	Amount			
Balance as of January 1, 2015	46,127,924	$461	$915,436	$187,544	$1,103,441
Stock options exercised for cash	2,433	—	46	—	46
Stock-based compensation expense	—	—	25,707	—	25,707
Issuance of common stock upon grants of restricted stock awards and vestings of restricted stock units	630,723	6	(150)	—	(144)
Sale of common stock, net of offering costs	11,500,000	115	470,043	—	470,158
Other	71,913	1	(1)	—	—
Net loss	—	—	—	(1,155,154)	(1,155,154)
Balance as of December 31, 2015	58,332,993	$583	$1,411,081	($967,610)	$444,054
Stock-based compensation expense	—	—	31,194	—	31,194
Issuance of common stock upon grants of restricted stock awards and vestings of restricted stock units	799,506	8	(63)	—	(55)
Sale of common stock, net of offering costs	6,000,000	60	223,679	—	223,739
Net loss	—	—	—	(675,474)	(675,474)
Balance as of December 31, 2016	65,132,499	$651	$1,665,891	($1,643,084)	$23,458
Stock-based compensation expense	—	—	23,625	—	23,625
Issuance of common stock upon grants of restricted stock awards and vestings of restricted stock units and performance shares	722,122	8	(42)	—	(34)
Sale of common stock, net of offering costs	15,600,000	156	222,222	—	222,378
Issuance of warrants	—	—	23,003	—	23,003
Dividends on preferred stock	—	—	(7,781)	—	(7,781)
Accretion on preferred stock	—	—	(862)	—	(862)
Net income	—	—	—	87,110	87,110
Balance as of December 31, 2017	81,454,621	$815	$1,926,056	($1,555,974)	$370,897

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,		
	2017	2016	2015
Cash Flows From Operating Activities			
Net income (loss)	$87,110	($675,474)	($1,155,154)
Income from discontinued operations, net of income taxes	—	—	(2,731)
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities from continuing operations			
Depreciation, depletion and amortization	262,589	213,962	300,035
Impairment of proved oil and gas properties	—	576,540	1,224,367
(Gain) loss on derivatives, net	59,103	49,073	(99,261)
Cash received for derivative settlements, net	7,773	119,369	194,296
Loss on extinguishment of debt	4,170	—	38,137
Stock-based compensation expense, net	14,309	36,086	14,729
Deferred income taxes	3,635	—	(140,875)
Non-cash interest expense, net	3,657	4,172	4,289
Other, net	2,337	3,753	5,709
Changes in components of working capital and other assets and liabilities-			
Accounts receivable	(41,630)	(12,836)	29,781
Accounts payable	11,822	(30,130)	(12,617)
Accrued liabilities	11,512	(7,938)	(17,517)
Other assets and liabilities, net	(3,406)	(3,809)	(4,453)
Net cash provided by operating activities from continuing operations	422,981	272,768	378,735
Net cash used in operating activities from discontinued operations	—	—	(1,368)
Net cash provided by operating activities	422,981	272,768	377,367
Cash Flows From Investing Activities			
Capital expenditures	(654,711)	(480,929)	(675,952)
Acquisitions of oil and gas properties	(695,774)	(153,521)	(1,817)
Net proceeds from divestitures of oil and gas properties	197,564	15,564	8,047
Other, net	(6,531)	(946)	(3,654)
Net cash used in investing activities from continuing operations	(1,159,452)	(619,832)	(673,376)
Net cash used in investing activities from discontinued operations	—	—	(2,678)
Net cash used in investing activities	(1,159,452)	(619,832)	(676,054)
Cash Flows From Financing Activities			
Issuance of senior notes	250,000	—	650,000
Tender and redemptions of senior notes	(152,813)	—	(626,681)
Payment of deferred purchase payment	—	—	(150,000)
Borrowings under credit agreement	1,992,523	770,291	1,126,860
Repayments of borrowings under credit agreement	(1,788,223)	(683,291)	(1,126,860)
Payments of debt issuance costs and credit facility amendment fees	(9,051)	(1,330)	(12,420)
Sale of common stock, net of offering costs	222,378	223,739	470,158
Sale of preferred stock, net of offering costs	236,404	—	—
Payment of dividends on preferred stock	(7,781)	—	—
Proceeds from stock options exercised	—	—	46
Other, net	(1,620)	(1,069)	(336)
Net cash provided by financing activities from continuing operations	741,817	308,340	330,767
Net cash provided by financing activities from discontinued operations	—	—	—
Net cash provided by financing activities	741,817	308,340	330,767
Net Increase (Decrease) in Cash and Cash Equivalents	5,346	(38,724)	32,080
Cash and Cash Equivalents, Beginning of Year	4,194	42,918	10,838
Cash and Cash Equivalents, End of Year	$9,540	$4,194	$42,918

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

1. Nature of Operations

Carrizo Oil & Gas, Inc. is a Houston-based energy company which, together with its subsidiaries (collectively, the "Company"), is actively engaged in the exploration, development, and production of crude oil, NGLs, and gas from resource plays located in the United States. The Company's current operations are principally focused in proven, producing oil and gas plays primarily in the Eagle Ford Shale in South Texas and the Permian Basin in West Texas.

2. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Company after elimination of intercompany transactions and balances and are presented in accordance with U.S. generally accepted accounting principles ("GAAP"). The Company proportionately consolidates its undivided interests in oil and gas properties as well as investments in unincorporated entities, such as partnerships and limited liability companies where the Company, as a partner or member, has undivided interests in the oil and gas properties. Certain reclassifications have been made to prior period amounts to conform to the current period presentation. Such reclassifications had no material impact on prior period amounts.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Certain of such estimates and assumptions are inherently unpredictable and will differ from actual results. The Company evaluates subsequent events through the date the financial statements are issued.

Significant estimates include volumes of proved oil and gas reserves, which are used in calculating depreciation, depletion and amortization ("DD&A") of proved oil and gas property costs, the present value of estimated future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and the estimated costs and timing of cash outflows underlying asset retirement obligations. Oil and gas reserve estimates, and therefore calculations based on such reserve estimates, are subject to numerous inherent uncertainties, the accuracy of which, is a function of the quality and quantity of available data, the application of engineering and geological interpretation and judgment to available data and the interpretation of mineral leaseholds and other contractual arrangements, including adequacy of title and drilling requirements. These estimates also depend on assumptions regarding quantities and production rates of recoverable oil and gas reserves, oil and gas prices, timing and amounts of development costs and operating expenses, all of which will vary from those assumed in the Company's estimates. Other significant estimates are involved in determining acquisition date fair values of assets acquired and liabilities assumed, impairments of unevaluated leasehold costs, fair values of derivative assets and liabilities, fair values of contingent consideration, preferred stock fair value upon issuance, grant date fair value of stock-based awards, and evaluating disputed claims, interpreting contractual arrangements and contingencies. Estimates are based on current assumptions that may be materially affected by the results of subsequent drilling and completion, testing and production as well as subsequent changes in oil and gas prices, interest rates and the market value and volatility of the Company's common stock.

Cash and Cash Equivalents

Cash equivalents include highly liquid investments with original maturities of three months or less. Certain of the Company's cash accounts are zero-balance controlled disbursement accounts that do not have the right of offset against the Company's other cash balances. The outstanding checks written against these zero-balance accounts have been classified as a component of accounts payable in the consolidated balance sheets and totaled $62.6 million and $34.3 million as of December 31, 2017 and 2016, respectively.

Accounts Receivable

As of December 31, 2017 payables due to related parties were less than $0.1 million and as of December 31, 2016, receivables due from related parties were $0.9 million. The Company establishes an allowance for doubtful accounts when it determines that it will not collect all or a part of an accounts receivable balance. The Company assesses the collectability of its accounts receivable on a quarterly basis and adjusts the allowance as necessary using the specific identification method. As of December 31, 2017 and 2016, the Company's allowance for doubtful accounts was $0.4 million and $0.8 million, respectively.

Concentration of Credit Risk

The Company's accounts receivable consists primarily of receivables from oil and gas purchasers and joint interest owners in properties the Company operates. This concentration of accounts receivable from oil and gas purchasers and joint interest owners in the oil and gas industry may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other industry conditions. The Company generally does not require collateral from its purchasers or joint interest owners. The Company generally has the right to withhold revenue distributions to recover past due receivables from joint interest owners.

Major Customers

Shell Trading (US) Company accounted for approximately 69%, 56%, and 65% of the Company's total revenues in 2017, 2016, and 2015, respectively. Flint Hills Resources, LP, an indirect wholly owned subsidiary of Koch Industries, Inc. accounted for approximately 7%, 15% and 9% of the Company's total revenues in 2017, 2016 and 2015, respectively.

Oil and Gas Properties

Oil and gas properties are accounted for using the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities are capitalized to cost centers established on a country-by-country basis. The internal cost of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities are capitalized to either proved or unproved oil and gas properties based on the type of activity and totaled $14.8 million, $10.5 million and $15.8 million for the years ended December 31, 2017, 2016 and 2015, respectively. Internal costs related to production, general corporate overhead and similar activities are expensed as incurred.

Capitalized oil and gas property costs within a cost center are amortized on an equivalent unit-of-production method, converting natural gas to barrels of oil equivalent at the ratio of six thousand cubic feet of gas to one barrel of oil, which represents their approximate relative energy content. The equivalent unit-of-production amortization rate is computed on a quarterly basis by dividing current quarter production by proved oil and gas reserves at the beginning of the quarter then applying such amortization rate to proved oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values. Average DD&A per Boe of proved oil and gas properties was $13.09, $13.50 and $22.05 for the years ended December 31, 2017, 2016 and 2015, respectively.

Unproved properties, not being amortized, include unevaluated leasehold and seismic costs associated with specific unevaluated properties and related capitalized interest. Individually significant unevaluated leaseholds are assessed on a quarterly basis to determine whether or not and to what extent proved reserves have been assigned to the properties or if an impairment has occurred, in which case the related costs along with associated capitalized interest are reclassified to proved oil and gas properties. Factors the Company considers in its impairment assessment include drilling results by the Company and other operators, the terms of oil and gas leases not held by production and drilling, completion, and infrastructure capital expenditure plans. Individually insignificant unevaluated leaseholds are grouped by major area and added to proved oil and gas properties based on the average primary lease term of the properties. Geological and geophysical costs not associated with specific prospects are recorded to proved oil and gas property costs as incurred. The Company capitalized interest costs to unproved properties totaling $28.3 million, $17.0 million and $32.1 million for the years ended December 31, 2017, 2016 and 2015, respectively. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unproved properties and the weighted average interest rate of outstanding borrowings.

At the end of each quarter, the net book value of oil and gas properties, less related deferred income taxes, are limited to the "cost center ceiling" equal to (i) the sum of (a) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (b) the costs of unproved properties not being amortized, and (c) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and gas properties, less related deferred income taxes, over the cost center ceiling is recognized as an impairment of proved oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher commodity prices in the future result in a cost center ceiling in excess of the net book value of oil and gas properties, less related deferred income taxes.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of crude oil, NGLs and natural gas on the first calendar day of each month during the 12-month period prior to the end of the current quarter ("12-Month Average Realized Price"), held flat for the life of the production, except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of derivative instruments as the Company elected not to meet the criteria to qualify derivative instruments for hedge accounting treatment.

The Company did not recognize impairments of proved oil and gas properties for the year ended December 31, 2017. For the years ended December 31, 2016 and 2015, the Company recorded impairments of proved oil and gas properties of $576.5 million and $1,224.4 million, due primarily to declines in the 12-Month Average Realized Price of crude oil.

Proceeds from the sale of proved and unproved oil and gas properties are recognized as a reduction of proved oil and gas property costs with no gain or loss recognized, unless the sale significantly alters the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For the years ended December 31, 2017, 2016 and 2015, the Company did not have any sales of oil and gas properties that significantly altered such relationship. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties."

Depreciation of other property and equipment is recognized using the straight-line method based on estimated useful lives ranging from three to ten years.

Debt Issuance Costs

Debt issuance costs associated with the revolving credit facility are amortized to interest expense on a straight-line basis over the term of the facility. Debt issuance costs associated with the senior notes are amortized to interest expense using the effective interest method over the terms of the related notes. Debt issuance costs associated with the revolving credit facility are classified in "Other assets" in the consolidated balance sheets while the debt issuance costs associated with the senior notes are classified as a reduction of the related long-term debt in the consolidated balance sheets.

Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, receivables, payables, commodity derivative assets and liabilities, contingent consideration determined to be embedded derivatives and long-term debt. The carrying amounts of cash and cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the Company's commodity derivative assets and liabilities are based on a third-party industry-standard pricing model using contract terms and prices and assumptions and inputs that are substantially observable in active markets throughout the full term of the instruments, including forward oil and gas price curves, discount rates, volatility factors and credit risk adjustments. The fair values of the Company's contingent consideration are determined by a third-party valuation specialist using Monte Carlo simulations including significant inputs such as future commodity prices, volatility factors for the future commodity prices and a risk adjusted discount rate.

The carrying amount of long-term debt associated with borrowings outstanding under the Company's revolving credit facility approximates fair value as borrowings bear interest at variable rates. The carrying amounts of the Company's senior notes and other long-term debt may not approximate fair value because carrying amounts are net of unamortized premiums and debt issuance costs, and the senior notes and other long-term debt bear interest at fixed rates. See "Note 6. Long-Term Debt" and "Note 12. Fair Value Measurements."

Asset Retirement Obligations

The Company's asset retirement obligations represent the present value of the estimated future costs associated with plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land in accordance with the terms of oil and gas leases and applicable local, state and federal laws. Determining asset retirement obligations requires estimates of the costs of plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land as well as estimates of the economic lives of the oil and gas wells and future inflation rates. The resulting estimate of future cash outflows are discounted using a credit-adjusted risk-free interest rate that corresponds with the timing of the cash outflows. Cost estimates consider historical experience, third party estimates, the requirements of oil and gas leases and applicable local, state and federal laws, but do not consider estimated salvage values. Asset retirement obligations are recognized when the well is drilled or acquired or when the production equipment and facilities are installed or acquired with an associated increase in proved oil and gas property costs. Asset retirement obligations are accreted each period through DD&A to their expected settlement values with any difference between the actual cost of settling the asset retirement obligations and recorded amount being recognized as an adjustment to proved oil and gas property costs. Cash paid to settle asset retirement obligations is included in net cash provided by operating activities from continuing operations in the consolidated statements of cash flows. On a quarterly basis, when indicators suggest there have been material changes in the estimates underlying the obligation, the Company reassesses its asset retirement obligations to determine whether any revisions to the obligations are necessary. At least annually, the Company reassesses all of its asset retirement obligations to determine whether any revisions to the obligations are necessary. Revisions typically occur due to changes in estimated costs or well economic lives, or if federal or state regulators enact new requirements regarding plugging and abandoning oil and gas wells. See "Note 7. Asset Retirement Obligations."

Commitments and Contingencies

Liabilities are recognized for contingencies when (i) it is both probable that an asset has been impaired or that a liability has been incurred and (ii) the amount of such loss is reasonably estimable. See “Note 8. Commitments and Contingencies.”

Revenue Recognition

Crude oil, NGL and natural gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability is reasonably assured. The Company follows the sales method of accounting whereby revenues from the production of natural gas from properties in which the Company has an interest with other producers are recognized for production sold to purchasers, regardless of whether the sales are proportionate to the Company’s ownership interest in the property. Production imbalances are recognized as a liability to the extent that the Company has an imbalance on a specific property that is in excess of its remaining proved reserves. Sales volumes are not significantly different from the Company’s share of production and as of December 31, 2017 and 2016, the Company did not have any material production imbalances.

Derivative Instruments

The Company uses commodity derivative instruments to reduce its exposure to commodity price volatility for a portion of its forecasted crude oil, NGL, and natural gas production and thereby achieve a more predictable level of cash flows to support the Company’s drilling, completion, and infrastructure capital expenditure program. All derivative instruments are recorded in the consolidated balance sheets as either an asset or liability measured at fair value. The Company nets its commodity derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. As the Company has elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment, gains and losses as a result of changes in the fair value of commodity derivative instruments are recognized as (gain) loss on derivatives, net in the consolidated statements of operations in the period in which the changes occur. The net cash flows resulting from the payments to and receipts from counterparties as a result of derivative settlements are classified as cash flows from operating activities. The Company does not enter into derivative instruments for speculative or trading purposes.

The Company’s Board of Directors establishes risk management policies and, on a quarterly basis, reviews its commodity derivative instruments, including volumes, types of instruments and counterparties. These policies require that commodity derivative instruments be executed only by the President or Chief Financial Officer after consultation with and concurrence by the President, Chief Financial Officer and Chairman of the Board. See “Note 11. Derivative Instruments” for further discussion of the Company’s commodity derivative instruments.

The Company has entered into agreements for acquisitions or divestitures of oil and gas properties that include obligations to pay the seller or rights to receive from the buyer, respectively, additional consideration if commodity prices exceed certain thresholds during certain specified periods in the future. These contingent consideration liabilities and assets are required to be bifurcated and accounted for separately as derivative instruments as they are not considered to be clearly and closely related to the host contract, and recognized at their acquisition or divestiture date fair value in the consolidated balance sheet, with subsequent changes in fair value recognized as (gain) loss on derivatives, net in the consolidated statements of operations in the period in which the changes occur. Cash payments made to settle contingent consideration liabilities are classified as cash flows from financing activities up to the acquisition date fair value with any excess classified as cash flows from operating activities. See “Note 3. Acquisitions and Divestitures of Oil and Gas Properties” and “Note 11. Derivative Instruments” for further discussion of the contingent consideration.

Preferred Stock and Warrants

The Company applies the accounting standards for distinguishing liabilities from equity when determining the classification and measurement of preferred stock. Preferred stock that is not mandatorily redeemable is excluded from liability classification and is evaluated for classification in shareholders’ equity or temporary equity. As the number of common shares that could be delivered upon the holders’ optional redemption is indeterminate, the Company cannot assert that it will be able to settle in shares of its common stock and, as a result, presents preferred stock as temporary equity. On a quarterly basis, the Company reassesses the presentation of preferred stock in the consolidated balance sheets.

When preferred stock is issued in conjunction with warrants, the warrants are evaluated separately as a freestanding financial instrument to determine whether they must be recorded as a derivative instrument. The Company further evaluates the warrants for equity classification and have determined the warrants qualify for equity classification and, therefore, are presented in additional paid-in capital in the consolidated balance sheets. The preferred stock and warrants are recorded based on the net proceeds received allocated to the two instrument’s relative fair values. The preferred stock is subject to accretion from its relative fair value at the issuance date to the redemption value using the effective interest method. The warrants do not require further adjustments from their relative fair value at the issuance date.

Dividends and accretion associated with preferred stock are presented in the consolidated statements of operations as reductions to net income, or increases of net loss, to derive net income (loss) attributable to common shareholders. Dividend payments are presented as a financing activity in the consolidated statement of cash flows.

See "Note 9. Preferred Stock and Warrants" for further details of the Company's outstanding preferred stock and warrants.

Stock-Based Compensation

The Company recognized stock-based compensation expense associated with restricted stock awards and units, stock appreciation rights to be settled in cash ("SARs") and performance share awards, which is reflected as general and administrative expense in the consolidated statements of operations, net of amounts capitalized to oil and gas properties. See "Note 10. Shareholders' Equity and Stock Based Compensation" for further details of the awards discussed below.

Restricted Stock Awards and Units. Stock-based compensation expense is based on the price of the Company's common stock on the grant date and recognized over the vesting period (generally one to three years) using the straight-line method, except for awards or units with performance conditions, in which case the Company uses the graded vesting method. For restricted stock awards and units granted to independent contractors, stock-based compensation expense is based on fair value remeasured at each reporting period and recognized over the vesting period (generally three years) using the straight-line method, except for awards or units with performance conditions, in which case the Company uses the graded vesting method.

Stock Appreciation Rights. For SARs, stock-based compensation expense is initially based on the grant date fair value determined using a Black-Scholes-Merton option pricing model, with the fair value liability subsequently remeasured at the end of each reporting period and recognized over the vesting period (generally two or three years) using the graded vesting method. For periods subsequent to vesting and prior to exercise, stock-based compensation expense is based on the fair value liability remeasured at the end of each reporting period based on the intrinsic value of the SAR. The liability for SARs is classified as "Other current liabilities" for the portion of the fair value liability attributable to awards that are vested or are expected to vest within the next 12 months and have an exercise price in excess of the market price at the end of the reporting period, with the remainder classified as "Other liabilities" in the consolidated balance sheets. SARs typically expire between four and seven years after the date of grant. If SARs expire unexercised, the cumulative compensation costs associated with the unexercised SARs will be zero.

Performance Share Awards. For performance share awards, stock-based compensation expense is based on the grant date fair value determined using a Monte Carlo valuation model and recognized over an approximate three year vesting period using the straight-line method. The number of shares of common stock issuable upon vesting ranges from zero to 200% of the number of performance share awards granted based on the Company's total shareholder return relative to a specified industry peer group over an approximate three year performance period. Compensation costs related to the performance share awards will be recognized if the requisite service period is fulfilled and the performance condition is met, even if the market condition is not achieved.

Income Taxes

Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are recognized at the end of each reporting period for the future tax consequences of cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the Company's financial statements based on existing tax laws and enacted statutory tax rates applicable to the periods in which the temporary differences are expected to affect taxable income. The Company assesses the realizability of its deferred tax assets on a quarterly basis by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The Company considers all available evidence (both positive and negative) when determining whether a valuation allowance is required. In making this assessment, the Company evaluates possible sources of taxable income that may be available to realize the deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies. See "Note 5. Income Taxes" for further discussion of the deferred tax assets valuation allowance. The Company classifies interest and penalties associated with income taxes as interest expense. The Company applies the tax law ordering approach to determine the sequence in which deferred tax assets and other tax attributes are utilized.

Net Income (Loss) Attributable to Common Shareholders Per Common Share

Basic net income (loss) attributable to common shareholders per common share is based on the weighted average number of shares of common stock outstanding during the year. Diluted net income (loss) attributable to common shareholders per common share is based on the weighted average number of common shares and all potentially dilutive common shares outstanding during the year which include restricted stock awards and units, performance share awards, stock options and warrants. The Company includes the number of restricted stock awards and units, stock options and warrants in the calculation of diluted weighted average shares outstanding when the grant date or exercise prices are less than the average market prices of the Company's common stock for the period. The Company includes the number of performance share awards in the calculation of diluted weighted average common shares outstanding based on the number of shares, if any, that would be issuable as if the end of the period was the end of the performance period. When a loss attributable to common shareholders exists, all potentially dilutive common shares outstanding are anti-dilutive and therefore excluded from the calculation of diluted weighted average shares outstanding.

Supplemental net income (loss) attributable to common shareholders per common share information is provided below:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands, except per share amounts)		
Net Income (Loss) Attributable to Common Shareholders	$78,467	($675,474)	($1,155,154)
Basic weighted average common shares outstanding	73,421	59,932	51,457
Effect of dilutive instruments	572	—	—
Diluted weighted average common shares outstanding	73,993	59,932	51,457
Net Income (Loss) Attributable to Common Shareholders Per Common Share			
Basic	$1.07	($11.27)	($22.45)
Diluted	$1.06	($11.27)	($22.45)

When the Company recognizes a net loss attributable to common shareholders, as was the case for the years ended December 31, 2016 and 2015, all potentially dilutive shares are anti-dilutive and excluded from the calculation of diluted weighted average common shares outstanding. The table below presents the weighted average dilutive and anti-dilutive shares outstanding for the periods presented:

	Years Ended December 31,		
	2017	2016	2015
		(In thousands)	
Dilutive	572	—	—
Anti-dilutive	52	669	649

Recently Adopted Accounting Pronouncement

Stock Compensation. In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"), which amends certain aspects of accounting for share-based payment arrangements. ASU 2016-09 revises or provides alternative accounting for the tax impacts of share-based payment arrangements, forfeitures, minimum statutory tax withholdings, and prescribes certain disclosures to be made in the period of adoption.

Effective January, 1, 2017, the Company adopted ASU 2016-09. Using the modified retrospective approach as prescribed by ASU 2016-09, the Company recognized previously unrecognized windfall tax benefits which resulted in a cumulative-effect adjustment to retained earnings of approximately $15.7 million. This adjustment increased deferred tax assets, which in turn increased the valuation allowance by the same amount as of the beginning of 2017, resulting in a net cumulative-effect adjustment to retained earnings of zero. Effective January 1, 2017, all windfall tax benefits and tax shortfalls are recorded as income tax expense or benefit in the consolidated statements of operations, whereas prior to adoption, windfall tax benefits were recorded as an increase to additional paid-in capital. In addition, windfall tax benefits, along with tax shortfalls, are now required to be classified as an operating cash flow as opposed to a financing cash flow. Further, the Company has elected to account for forfeitures of share-based payment awards as they occur, which resulted in an immaterial cumulative-effect adjustment to retained earnings.

Recently Issued Accounting Pronouncements

Revenue From Contracts With Customers. In May 2014, the FASB issued ASU No. 2014-09, Revenue From Contracts With Customers (Topic 606) ("ASU 2014-09"). Under the new standard, revenue is recognized when a customer obtains control of promised goods or services in an amount that reflects the consideration the entity expects to receive in exchange for those goods or services. In addition, the standard requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers.

The Company will adopt ASU 2014-09 effective January 1, 2018, using the modified retrospective approach, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. The Company has performed an analysis of existing contracts and does not expect adoption to have a material impact on its consolidated financial statements, however, certain immaterial natural gas processing fees, which have historically been netted in revenue, will be recorded to lease operating expense. In addition, the Company has evaluated the expected changes to relevant business practices, accounting policies and control activities and does not expect to have a material change as a result of the adoption of ASU 2014-09.

Business Combinations. In January 2017, the FASB issued ASU No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business ("ASU 2017-01"), which clarifies the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The Company will adopt ASU 2017-01 effective January 1, 2018 on a prospective basis.

Statement of Cash Flows. In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments ("ASU 2016-15"), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The guidance addresses eight specific cash flow issues for which current GAAP is either unclear or does not include specific guidance. The Company will adopt ASU 2016-15 effective January 1, 2018 using the full retrospective method, meaning the standard is applied to all periods presented. The Company does not expect the impact of adopting ASU 2016-15 to have a material effect on its consolidated statements of cash flows and related disclosures.

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which significantly changes accounting for leases by requiring that lessees recognize a right-of-use asset and a related lease liability representing the obligation to make lease payments, for virtually all lease transactions. Additional disclosures about an entity's lease transactions will also be required. ASU 2016-02 defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration." ASU 2016-02 is effective for interim and annual periods beginning after December 15, 2018 with early adoption permitted. ASU 2016-02 requires companies to recognize and measure leases at the beginning of the earliest period presented in the financial statements using a modified retrospective approach.

The Company is currently assessing the impact of ASU 2016-02 which includes an analysis of existing contracts, including drilling rig contracts, office leases, certain field equipment, vehicles, produced water disposal commitments, pipeline gathering, transportation and gas processing agreements and current accounting policies and disclosures that will change as a result of adopting ASU 2016-02. Appropriate systems, controls, and processes to support the recognition and disclosure requirements of the new standard are also being evaluated. The Company currently expects the adoption of ASU 2016-02 will result in: (i) an increase in assets and liabilities, (ii) an increase in depreciation, depletion and amortization expense, (iii) an increase in interest expense, and (iv) additional disclosures. The Company plans to adopt the guidance effective January 1, 2019.

3. Acquisitions and Divestitures of Oil and Gas Properties

Acquisitions

ExL Acquisition. On June 28, 2017, the Company entered into a purchase and sale agreement with ExL Petroleum Management, LLC and ExL Petroleum Operating Inc. (together "ExL") to acquire oil and gas properties located in the Delaware Basin in Reeves and Ward Counties, Texas (the "ExL Properties") for an agreed upon price of $648.0 million, with an effective date of May 1, 2017, subject to customary purchase price adjustments (the "ExL Acquisition"). The Company paid $75.0 million as a deposit on June 28, 2017, $601.0 million upon closing on August 10, 2017 and $3.8 million upon post-closing on December 8, 2017, for an aggregate cash consideration of $679.8 million, which included purchase price adjustments primarily related to the net cash flows from the effective date to the closing date. Upon closing the ExL Acquisition, the Company became the operator of the ExL Properties with an approximate 70% average working interest.

The Company also agreed to pay an additional $50.0 million per year if the average daily closing spot price of a barrel of West Texas Intermediate crude oil as measured by the U.S. Energy Information Administration (the "EIA WTI average price") is above $50.00 for any of the years of 2018, 2019, 2020 and 2021, with such payments due on January 29, 2019, January 28, 2020, January 28, 2021 and January 28, 2022, respectively. This payment (the "Contingent ExL Consideration") will be zero for the respective year if such EIA WTI average price of a barrel of oil is $50.00 or below for any of such years, and the Contingent ExL Consideration is capped at $125.0 million in the aggregate. The Company determined that the Contingent ExL Consideration is an embedded derivative and has reflected the liability at fair value in non-current "Derivative liabilities" in the consolidated balance sheets. The fair value of the Contingent ExL Consideration as of December 31, 2017 and August 10, 2017 was $85.6 million and $52.3 million, respectively. See "Note 11. Derivative Instruments" and "Note 12. Fair Value Measurements" for further details.

The Company funded the ExL Acquisition with net proceeds from the sale of preferred stock on August 10, 2017, net proceeds from the common stock offering completed on July 3, 2017, and net proceeds from the senior notes offering completed on July 14, 2017. See "Note 9. Preferred Stock and Warrants" for details regarding the sale of Preferred Stock, "Note 10. Shareholders' Equity and Stock-Based Compensation" for details regarding the common stock offering and "Note 6. Long-Term Debt" for details regarding the senior notes offering.

The ExL Acquisition was accounted for as a business combination, therefore, the purchase price was allocated to the assets acquired and the liabilities assumed based on their estimated acquisition date fair values based on then currently available information. A combination of a discounted cash flow model and market data was used by a third-party valuation specialist in determining the fair value of the oil and gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and gas reserves, expectations for timing and amount of future development and operating costs, future plugging and abandonment costs and a risk adjusted discount rate. The fair value of the Contingent ExL Consideration was determined by a third-party valuation specialist using a Monte Carlo simulation. Significant inputs into the calculation included future commodity prices, volatility factors for the future commodity prices and a risk adjusted discount rate. See “Note 12. Fair Value Measurements” for further details.

The following presents the final allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

	Purchase Price Allocation
	(In thousands)
Assets	
Other current assets	$106
Oil and gas properties	
Proved properties	294,754
Unproved properties	443,194
Total oil and gas properties	$737,948
Total assets acquired	$738,054
Liabilities	
Revenues and royalties payable	$5,785
Asset retirement obligations	153
Contingent ExL Consideration	52,300
Total liabilities assumed	$58,238
Net Assets Acquired	$679,816

Included in the consolidated statements of operations for the year ended December 31, 2017 are total revenues of $53.5 million and net income attributable to common shareholders of $44.3 million from the ExL Acquisition, representing activity of the acquired properties subsequent to the closing of the transaction.

Pro Forma Operating Results (Unaudited). The following unaudited pro forma financial information presents a summary of the Company’s consolidated results of operations for the years ended December 31, 2017 and 2016, assuming the ExL Acquisition had been completed as of January 1, 2016, including adjustments to reflect the acquisition date fair values assigned to the assets acquired and liabilities assumed. The pro forma financial information does not purport to represent what the actual results of operations would have been had the transactions been completed as of the date assumed, nor is this information necessarily indicative of future consolidated results of operations. The Company believes the assumptions used provide a reasonable basis for reflecting the significant pro forma effects directly attributable to the ExL Acquisition.

	Years Ended December 31,	
	2017	2016
	(In thousands, except per share amounts)	
Total revenues	$781,378	$454,913
Net Income (Loss) Attributable to Common Shareholders	$91,931	($688,180)
Net Income (Loss) Attributable to Common Shareholders Per Common Share		
Basic	$1.25	($9.11)
Diluted	$1.24	($9.11)
Weighted Average Common Shares Outstanding		
Basic	73,421	75,532
Diluted	73,993	75,532

Sanchez Acquisition. On October 24, 2016, the Company entered into a purchase and sale agreement with Sanchez Energy Corporation and SN Cotulla Assets, LLC, a subsidiary of Sanchez Energy Corporation to acquire oil and gas properties located in the Eagle Ford Shale (the "Sanchez Acquisition") for an agreed upon price of $181.0 million, with an effective date of June 1, 2016, subject to customary purchase price adjustments. The Company paid $10.0 million as a deposit on October 24, 2016, $143.5 million upon the initial closing on December 14, 2016, and $7.0 million and $9.8 million on January 9, 2017 and April 13, 2017, respectively, for leases that were not conveyed to the Company at the time of the initial closing, for aggregate cash consideration of $170.3 million, which included purchase price adjustments primarily related to the net cash flows from the effective date to the closing date. The Sanchez Acquisition was accounted for as a business combination, therefore, the purchase price was allocated to the assets acquired and liabilities assumed based on their estimated acquisition date fair values based on then available information.

The following presents the final allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

	Purchase Price Allocation
	(In thousands)
Assets	
Other current assets	$477
Oil and gas properties	
Proved properties	99,938
Unproved properties	74,536
Total oil and gas properties	174,474
Total assets acquired	$174,951
Liabilities	
Revenues and royalties payable	$1,442
Other current liabilities	323
Asset retirement obligations	2,054
Other liabilities	1,078
Total liabilities assumed	$4,897
Net Assets Acquired	$170,054

Included in the consolidated statements of operations for the year ended December 31, 2017 are total revenues of $37.8 million and net income attributable to common shareholders of $16.5 million from the Sanchez Acquisition, representing activity of the acquired properties subsequent to the closing of the transaction.

Divestitures

Utica. On August 31, 2017, the Company entered into a purchase and sale agreement to sell substantially all of its assets in the Utica Shale, located primarily in Guernsey County, Ohio, for an agreed upon price of $62.0 million, with an effective date of April 1, 2017, subject to customary purchase price adjustments. On August 31, 2017, the Company received $6.2 million as a deposit, on November 15, 2017, the Company received $54.4 million at closing, subject to post-closing adjustments, and on December 28, 2017, the Company received $2.5 million, for aggregate net proceeds of $63.1 million, which includes preliminary purchase price adjustments primarily related to the net cash flows from the effective date to the closing date.

The Company could also receive contingent consideration of $5.0 million per year if the average daily closing spot price of a barrel of West Texas Intermediate crude oil as measured by the U.S. Energy Information Administration (the "EIA WTI average price") is above $50.00, $53.00, and $56.00 for the years of 2018, 2019, and 2020, respectively, with such receipts due on January 29, 2019, January 28, 2020, and January 28, 2021, respectively (the "Contingent Utica Consideration"). The Contingent Utica Consideration will be zero for the respective year if such EIA WTI average price of a barrel of oil is at or below the per barrel amounts listed above for any of such years. The Company determined that the Contingent Utica Consideration is an embedded derivative and has reflected the asset at fair value in non-current "Other assets" in the consolidated balance sheets. The fair value of the Contingent Utica Consideration as of December 31, 2017 and November 15, 2017 was $8.0 million and $6.1 million, respectively. See "Note 11. Derivative Instruments" and "Note 12. Fair Value Measurements" for further details.

The aggregate net proceeds of $63.1 million were recognized as a reduction of proved oil and gas properties. The contingent consideration, if received, will be recognized as a reduction of the fair value asset in the consolidated balance sheets.

Marcellus. On October 5, 2017, the Company entered into a purchase and sale agreement with BKV Chelsea, LLC, a subsidiary of Kalnin Ventures LLC, to sell substantially all of its assets in the Marcellus Shale for an agreed upon price of $84.0 million, with an effective date of April 1, 2017, subject to customary purchase price adjustments. On October 5, 2017, the Company received $6.3 million into escrow as a deposit and on November 21, 2017, the Company received $67.6 million at closing, subject to post-closing adjustments, for aggregate net proceeds of $73.9 million, which includes preliminary purchase price adjustments primarily related to the net cash flows from the effective date to the closing date.

The Company could also receive contingent consideration of $3.0 million per year if the average settlement prices of a MMBtu of Henry Hub natural gas for the next calendar month, as determined on the last business day preceding each calendar month as measured by the CME Group Inc. (the "CME HH average price") is above $3.13, $3.18, and $3.30 for the years of 2018, 2019, and 2020, respectively, with such receipts due on January 29, 2019, January 28, 2020, and January 28, 2021, respectively (the "Contingent Marcellus Consideration"). This conditional consideration will be zero for the respective year if such CME HH average price of a MMBtu of Henry Hub natural gas is at or below the per MMBtu amounts listed above for any of such years, and is capped at $7.5 million. The Company determined that the Contingent Marcellus Consideration is an embedded derivative and has reflected the asset at fair value in non-current "Other assets" in the consolidated balance sheets. The fair value of the Contingent Marcellus Consideration as of December 31, 2017 and November 21, 2017 was $2.2 million and $2.7 million, respectively. See "Note 11. Derivative Instruments" and "Note 12. Fair Value Measurements" for further details.

The aggregate net proceeds of $73.9 million were recognized as a reduction of proved oil and gas properties. The contingent consideration, if received, will be recognized as a reduction of the fair value asset in the consolidated balance sheets.

Simultaneous with the signing of the Marcellus Shale transaction discussed above, the Company's existing joint venture partner in the Marcellus Shale, Reliance Marcellus II, LLC ("Reliance"), a wholly owned subsidiary of Reliance Holding USA, Inc. and an affiliate of Reliance Industries Limited, entered into a purchase and sale agreement with BKV Chelsea, LLC to sell its interest in the same oil and gas properties. Simultaneous with the closing of these Marcellus Shale sale transactions, the agreements governing the Reliance joint venture were assigned to the buyer and, after giving effect to such transactions, the Reliance joint venture was terminated except for limited post-closing obligations.

Niobrara. On November 20, 2017, the Company entered into a purchase and sale agreement to sell substantially all of its assets in the Niobrara Formation for an agreed upon price of $140.0 million, with an effective date of October 1, 2017, subject to customary purchase price adjustments. On November 20, 2017, the Company received $14.0 million as a deposit, which is refundable only in specified circumstances if the transaction is not consummated and is classified as "Other liabilities" in the consolidated balance sheets and as "Net proceeds from divestitures of oil and gas properties" in the cash flows from investing activities section in the consolidated statements of cash flows. On January 19, 2018, the Company received $122.6 million at closing, subject to post-closing adjustments, for aggregate net proceeds of $136.6 million, which includes preliminary purchase price adjustments primarily related to the net cash flows from the effective date to the closing date.

The Company could also receive contingent consideration of $5.0 million per year if the average daily closing spot price of a barrel of West Texas Intermediate crude oil as measured by the U.S. Energy Information Administration (the "EIA WTI average price") is above $55.00 for the years of 2018 and 2019 and above $60.00 for 2020, with such receipts due on January 29, 2019, January 28, 2020, and January 28, 2021, respectively (the "Contingent Niobrara Consideration"). The Contingent Niobrara Consideration will be zero for the respective year if such EIA WTI average price of a barrel of oil is at or below the per barrel amounts listed above for any of such years.

Eagle Ford. On December 11, 2017, the Company entered into a purchase and sale agreement with EP Energy E&P Company, L.P. to sell a portion of its assets in the Eagle Ford Shale for an agreed upon price of $245.0 million, with an effective date of October 1, 2017, subject to adjustment and customary terms and conditions. On December 11, 2017, the Company received $24.5 million as a deposit, which is refundable only in specified circumstances if the transaction is not consummated and is classified as "Other liabilities" in the consolidated balance sheets and as "Net proceeds from divestitures of oil and gas properties" in the cash flows from investing activities section in the consolidated statements of cash flows. On January 31, 2018, the Company received $211.7 million at closing, subject to post-closing adjustments, and on February 16, 2018, the Company received $10.0 million for leases that were not conveyed at closing, for aggregate net proceeds of $246.2 million, which includes preliminary purchase price adjustments primarily related to the net cash flows from the effective date to the closing date.

In the first quarter of 2018, the aggregate net proceeds that were received for the Niobrara and Eagle Ford divestitures will be recognized as reductions of proved oil and gas properties and the Contingent Niobrara Consideration will be recognized as an asset at fair value in the Company's consolidated balance sheet.

Other Assets. During the first quarter of 2017, the Company sold a small undeveloped acreage position in the Delaware Basin for net proceeds of $15.3 million. The proceeds from this sale were recognized as a reduction of proved oil and gas properties.

4. Property and Equipment, Net

As of December 31, 2017 and 2016, total property and equipment, net consisted of the following:

	December 31,	
	2017	2016
Oil and gas properties, full cost method	(In thousands)	
Proved properties	$5,615,153	$4,687,416
Accumulated DD&A and impairments	(3,649,806)	(3,392,749)
Proved properties, net	1,965,347	1,294,667
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	612,589	211,067
Capitalized interest	47,698	29,894
Total unproved properties, not being amortized	660,287	240,961
Other property and equipment	25,625	23,127
Accumulated depreciation	(15,449)	(12,995)
Other property and equipment, net	10,176	10,132
Total property and equipment, net	$2,635,810	$1,545,760

Costs not subject to amortization totaling $660.3 million at December 31, 2017 were incurred in the following periods: $523.1 million in 2017, $106.8 million in 2016 and $24.0 million in 2015.

Impairments of Proved Oil and Gas Properties

The Company did not recognize impairments of proved oil and gas properties for the year ended December 31, 2017. Primarily due to declines in the 12-Month Average Realized Price of crude oil, the Company recognized impairments of proved oil and gas properties of $576.5 million and $1,224.4 million for the years ended December 31, 2016 and 2015, respectively.

5. Income Taxes

The components of income tax (expense) benefit from continuing operations were as follows:

	Years Ended December 31,		
	2017	2016	2015
		(In thousands)	
Current income tax (expense) benefit			
U.S. Federal	$—	$—	$—
State	(395)	—	—
Total current income tax (expense) benefit	(395)	—	—
Deferred income tax (expense) benefit			
U.S. Federal	—	—	131,502
State	(3,635)	—	9,373
Total deferred income tax (expense) benefit	(3,635)	—	140,875
Total income tax (expense) benefit from continuing operations	($4,030)	$—	$140,875

The Company’s income tax (expense) benefit from continuing operations differs from the income tax (expense) benefit computed by applying the U.S. federal statutory corporate income tax rate of 35% to income (loss) from continuing operations before income taxes as follows:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Income (loss) from continuing operations before income taxes	$91,140	($675,474)	($1,298,760)
Income tax (expense) benefit at the statutory rate	(31,899)	236,416	454,566
State income tax (expense) benefit, net of U.S. Federal income taxes	(4,030)	3,894	9,373
Tax shortfalls from stock-based compensation expense	(3,089)	—	—
Texas Franchise Tax rate reduction, net of U.S. Federal income tax expense	—	—	1,671
Provisional impact of Tax Cuts and Jobs Act	(211,724)	—	—
Change in valuation allowance from provisional impact of Tax Cuts and Jobs Act	211,724	—	—
Change in valuation allowance from current year activity	35,376	(240,864)	(323,586)
Other	(388)	554	(1,149)
Income tax (expense) benefit	($4,030)	$—	$140,875

Significant changes in the Company’s operations in 2017, including the ExL Acquisition in the Delaware Basin and divestitures of substantially all of the Company's assets in the Utica and Marcellus Shales, resulted in changes to the Company's anticipated future state apportionment for estimated state deferred tax liabilities. As a result of these changes, the Company recorded a $3.6 million state deferred tax expense primarily associated with future Texas deferred tax liabilities.

Deferred Income Taxes

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. As of December 31, 2017 and 2016, deferred tax assets and liabilities are comprised of the following:

	December 31,	
	2017	2016
	(In thousands)	
Deferred income tax assets		
Net operating loss carryforward - U.S. Federal and State	$242,915	$221,063
Oil and gas properties	50,177	309,848
Asset retirement obligations	4,996	7,434
Stock-based compensation	—	5,238
Derivative liabilities	35,585	17,545
Other	1,496	3,739
Deferred income tax assets	335,169	564,867
Deferred tax asset valuation allowance	(333,029)	(564,434)
Net deferred income tax assets	2,140	433
Deferred income tax liabilities		
Oil and gas properties	(3,635)	—
Derivative assets	(2,140)	(433)
Net deferred income tax asset (liability)	($3,635)	$—

Tax Cuts and Jobs Act

On December 22, 2017, the U.S. Congress enacted the Tax Cuts and Jobs Act (the “Act”) which made significant changes to U.S. federal income tax law, including lowering the federal statutory corporate income tax rate to 21% from 35% beginning January 1, 2018. The income tax effects of changes in tax laws are recognized in the period when enacted. While the Company continues to assess the impact of the tax reform legislation on its business and consolidated financial statements, the Company remeasured its deferred tax balances by applying the reduced rate and and recorded a provisional deferred tax expense of $211.7 million during the year ended December 31, 2017. This provisional deferred tax expense was fully offset by a $211.7 million deferred tax benefit as a result of the associated change in the valuation allowance against the net deferred tax assets. As reflected in the rate reconciliation above, the change in the deferred tax balances due to the rate reduction had no impact on the net deferred tax balances reported in the consolidated balance sheets as of December 31, 2017 and no impact in the consolidated statements of operations for the year ended December 31, 2017.

Due to the uncertainty or diversity in views about the application of ASC 740 in the period of enactment of the Act, the SEC issued Staff Accounting Bulletin 118 ("SAB 118") which allows the Company to provide a provisional estimate of the impacts of the Act in its earnings for the year ended December 31, 2017. The Company's estimate does not reflect changes in current interpretations of performance based executive compensation deduction limitations, effects of any state tax law changes and uncertainties regarding interpretations that may arise as a result of federal tax reform. The Company will continue to analyze the effects of the Act in its consolidated financial statements and operations. Additional impacts from the enactment of the Act will be recorded as they are identified during the one-year measurement period provided for in SAB 118. As of December 31, 2017, the Company has not completed its accounting for the tax effects of enactment of the Act; however, the Company has made a reasonable estimate of the effects on it existing deferred tax balances.

Deferred Tax Assets Valuation Allowance

Deferred tax assets are recorded for net operating losses and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those deferred tax assets would be deductible. The Company assesses the realizability of its deferred tax assets on a quarterly basis by considering whether it is more likely than not that all or a portion of the deferred tax assets will not be realized. The Company considers all available evidence (both positive and negative) when determining whether a valuation allowance is required. In making this assessment, the Company evaluated possible sources of taxable income that may be available to realize the deferred tax assets, including projected future taxable income, the reversal of existing temporary differences, taxable income in carryback years and available tax planning strategies.

A significant item of objective negative evidence considered was the cumulative historical three year pre-tax loss and a net deferred tax asset position at December 31, 2017, driven primarily by the impairments of proved oil and gas properties recognized beginning in the third quarter of 2015 and continuing through the third quarter of 2016, which limits the ability to consider other subjective evidence such as the Company's potential for future growth. Beginning in the third quarter of 2015 and continuing through the fourth quarter of 2017, the Company concluded that it was more likely than not the deferred tax assets will not be realized. As a result, the net deferred tax assets at the end of each quarter, including December 31, 2017 were reduced to zero.

Effective January 1, 2017, the Company adopted ASU 2016-09, and the Company recognized previously unrecognized windfall tax benefits which resulted in a cumulative-effect adjustment to retained earnings of approximately $15.7 million. This adjustment increased deferred tax assets, which in turn increased the valuation allowance by the same amount as of the beginning of 2017, resulting in a net cumulative-effect adjustment to retained earnings of zero and brought the valuation allowance to $580.1 million as of January 1, 2017.

For the year ended December 31, 2017, the Company reduced the valuation allowance by $247.1 million. This was primarily due to the re-measurement of its deferred tax assets as a result of the Act as mentioned above as well as partial releases of $35.4 million, as a result of current year activity. After the impact of the re-measurement and the partial releases, the valuation allowance as of December 31, 2017 was $333.0 million, of which $12.7 million is a valuation allowance against state deferred tax assets.

The Company will continue to evaluate whether the valuation allowance is needed in future reporting periods. The valuation allowance will remain until the Company can conclude that the net deferred tax assets are more likely than not to be realized. Future events or new evidence which may lead the Company to conclude that it is more likely than not its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings, improvements in crude oil prices, and taxable events that could result from one or more transactions. The valuation allowance does not preclude the Company from utilizing the tax attributes if the Company recognizes sufficient taxable income within the carryforward periods. As long as the Company continues to conclude that the valuation allowance against its net deferred tax assets is necessary, the Company will have no significant federal deferred income tax expense or benefit. However, the Company currently expects to continue to have state deferred income tax expense or benefit as a result of change in state deferred tax liabilities as the Company's operations become more heavily weighted towards Texas.

Net Operating Loss Carryforwards and Other

Net Operating Loss Carryforwards. As of December 31, 2017, the Company had U.S. federal net operating loss carryforwards of approximately $1,096.2 million. If not utilized in earlier periods, the U.S. federal net operating loss will expire between 2026 and 2037.

The ability of the Company to utilize its U.S. loss carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended (the "Code"). The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of stock by 5% shareholders and the offering of stock by the Company during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of the Company. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of the Company's taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (i) the fair market value of the equity of the Company multiplied by (ii) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains inherent in the assets sold.

Due to the issuance of the Preferred Stock and the common stock offering associated with the ExL Acquisition, the Company's calculated ownership change percentage increased, however, as of December 31, 2017, the Company does not believe it has a Section 382 limitation on the ability to utilize its U.S. loss carryforwards. Future equity transactions involving the Company or 5% shareholders of the Company (including, potentially, relatively small transactions and transactions beyond the Company's control) could cause further ownership changes and therefore a limitation on the annual utilization of the U. S. loss carryforwards.

Other. The Company files income tax returns in the U.S. Federal jurisdiction and various states, each with varying statutes of limitations. The 1999 through 2017 tax years generally remain subject to examination by federal and state tax authorities. As of December 31, 2017, 2016 and 2015, the Company had no uncertain tax positions.

6. Long-Term Debt

Long-term debt consisted of the following as of December 31, 2017 and 2016:

	December 31,	
	2017	2016
	(In thousands)	
Senior Secured Revolving Credit Facility due 2022	$291,300	$87,000
7.50% Senior Notes due 2020	450,000	600,000
Unamortized premium for 7.50% Senior Notes	579	1,020
Unamortized debt issuance costs for 7.50% Senior Notes	(4,492)	(7,573)
6.25% Senior Notes due 2023	650,000	650,000
Unamortized debt issuance costs for 6.25% Senior Notes	(8,208)	(9,454)
8.25% Senior Notes due 2025	250,000	—
Unamortized debt issuance costs for 8.25% Senior Notes	(4,395)	—
Other long-term debt due 2028	4,425	4,425
Long-term debt	$1,629,209	$1,325,418

Senior Secured Revolving Credit Facility

The Company has a senior secured revolving credit facility with a syndicate of banks that, as of December 31, 2017, had a borrowing base of $900.0 million, with an elected commitment amount of $800.0 million, and $291.3 million of borrowings outstanding at a weighted average interest rate of 3.73%. As of December 31, 2017, the Company also had $0.4 million in letters of credit outstanding, which reduce the amounts available under the revolving credit facility. The credit agreement governing the revolving credit facility provides for interest-only payments until May 4, 2022 (subject to a springing maturity date of June 15, 2020 if the 7.50% Senior Notes have not been refinanced on or prior to such time), when the credit agreement matures and any outstanding borrowings are due. The borrowing base under the credit agreement is subject to regular redeterminations in the spring and fall of each year, as well as special redeterminations described in the credit agreement, which in each case may reduce the amount of the borrowing base. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement. The capitalized terms which are not defined in this description of the revolving credit facility, shall have the meaning given to such terms in the credit agreement.

On May 4, 2017, the Company entered into a ninth amendment to the credit agreement governing the revolving credit facility to, among other things, (i) extend the maturity date of the revolving credit facility to May 4, 2022, subject to a springing maturity date of June 15, 2020 if the 7.50% Senior Notes have not been refinanced or redeemed on or prior to such time, (ii) increase the maximum credit amount under the revolving credit facility from $1.0 billion to $2.0 billion, (iii) increase the borrowing base from $600.0 million to $900.0 million, with an elected commitment amount of $800.0 million, until the next redetermination thereof and (iv) amend certain financial covenants including replacing the Total Secured Debt to EBITDA ratio covenant with a Total Debt to EBITDA ratio and removing the minimum EBITDA to Interest Expense ratio.

On June 28, 2017, the Company entered into a tenth amendment to its credit agreement governing the revolving credit facility to, among other things, (i) amend the calculation of certain financial covenants to provide that EBITDA will be calculated on an annualized basis as of the end of each of the first three fiscal quarters commencing with the quarter ending September 30, 2017 and (ii) amend the restricted payments covenant.

Upon issuance of the 8.25% Senior Notes (described below), in accordance with the credit agreement governing the revolving credit facility, the Company's borrowing base was reduced by 25% of the aggregate principal amount of the 8.25% Senior Notes, reducing the Company's borrowing base from $900.0 million to $837.5 million.

On November 3, 2017, the Company entered into an eleventh amendment to its credit agreement governing the revolving credit facility to, among other things, (i) establish the borrowing base at $900.0 million, with an elected commitment amount of $800.0 million, until the next determination thereof, (ii) increase the general basket available for restricted payments from $50.0 million to $75.0 million and (iii) amend certain other provisions, in each case as set forth therein.

The obligations of the Company under the credit agreement are guaranteed by the Company's material domestic subsidiaries and are secured by liens on substantially all of the Company's assets, including a mortgage lien on oil and gas properties having at least 90% of the total value of the oil and gas properties included in the Company's reserve report used in its most recent redetermination.

Borrowings outstanding under the credit agreement bear interest at the Company's option at either (i) a base rate for a base rate loan plus the margin set forth in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% and the adjusted LIBO rate plus 1.00%, or (ii) an adjusted LIBO rate for a Eurodollar loan plus the margin set forth in the table below. The Company also incurs commitment fees at rates as set forth in the table below on the unused portion of lender commitments, which are included in interest expense, net in the consolidated statements of operations.

Ratio of Outstanding Borrowings and Letters of Credit to Lender Commitments	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 25%	1.00%	2.00%	0.375%
Greater than or equal to 25% but less than 50%	1.25%	2.25%	0.375%
Greater than or equal to 50% but less than 75%	1.50%	2.50%	0.500%
Greater than or equal to 75% but less than 90%	1.75%	2.75%	0.500%
Greater than or equal to 90%	2.00%	3.00%	0.500%

The Company is subject to certain covenants under the terms of the credit agreement, which include the maintenance of the following financial covenants determined as of the last day of each quarter: (1) a ratio of Total Debt to EBITDA of not more than 4.00 to 1.00 and (2) a Current Ratio of not less than 1.00 to 1.00. As defined in the credit agreement, Total Debt excludes debt premiums and debt issuance costs and is net of cash and cash equivalents, EBITDA for the fiscal quarter ended December 31, 2017 is calculated based on an annualized average of the last two fiscal quarters, EBITDA for the fiscal quarter ending March 31, 2018, will be calculated based on an annualized average of the last three fiscal quarters, and EBITDA for fiscal quarters ending thereafter will be calculated based on the last four fiscal quarters, in each case after giving pro forma effect to EBITDA for material acquisitions and dispositions of oil and gas properties, and the Current Ratio includes an add back of the unused portion of lender commitments. As of December 31, 2017, the ratio of Total Debt to EBITDA was 2.59 to 1.00 and the Current Ratio was 1.98 to 1.00. Because the financial covenants are determined as of the last day of each quarter, the ratios can fluctuate significantly period to period as the level of borrowings outstanding under the credit agreement are impacted by the timing of cash flows from operations, capital expenditures, acquisitions and divestitures of oil and gas properties and securities offerings.

The credit agreement also places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company's common stock, redemptions of senior notes, investments, acquisitions and divestitures of oil and gas properties, mergers, transactions with affiliates, hedging transactions and other matters.

The credit agreement is subject to customary events of default, including in connection with a change in control. If an event of default occurs and is continuing, the lenders may elect to accelerate amounts due under the credit agreement (except in the case of a bankruptcy event of default, in which case such amounts will automatically become due and payable).

Senior Notes

8.25% Senior Notes due 2025. On July 14, 2017, the Company closed a public offering of $250.0 million aggregate principal amount of 8.25% Senior Notes due 2025 (the "8.25% Senior Notes"). The 8.25% Senior Notes mature on July 15, 2025 and have interest payable semi-annually each January 15 and July 15. Before July 15, 2020, the Company may, at its option, redeem all or a portion of the 8.25% Senior Notes at 100% of the principal amount plus accrued and unpaid interest and a make-whole premium. Thereafter, the Company may redeem all or a portion of the 8.25% Senior Notes at redemption prices decreasing annually from

106.188% to 100% of the principal amount redeemed plus accrued and unpaid interest. The Company used the net proceeds of $245.4 million, net of underwriting discounts and commissions and offering costs, to fund a portion of the purchase price for the ExL Acquisition and for general corporate purposes. See “Note 3. Acquisitions and Divestitures of Oil and Gas Properties” for further details of the ExL Acquisition.

7.50% Senior Notes due 2020. On November 28, 2017, the Company delivered a notice of redemption to the trustee for its 7.50% Senior Notes due 2020 (the “7.50% Senior Notes”) to call for redemption on December 28, 2017, $150.0 million aggregate principal amount of the 7.50% Senior Notes then outstanding. On December 28, 2017, the Company paid an aggregate redemption price of $156.0 million, which included a redemption premium of $2.8 million as well as accrued and unpaid interest of $3.2 million from the last interest payment date up to, but not including, the redemption date. As a result of the redemption of $150.0 million of the 7.50% Senior Notes, the Company recorded a loss on extinguishment of debt of $4.2 million, which includes the redemption premium paid to redeem the notes and non-cash charges of $1.3 million attributable to the write-off of unamortized premium and debt issuance costs associated with the 7.50% Senior Notes. The Company delivered additional notices of redemption to the trustee for its 7.50% Senior Notes subsequent to December 31, 2017. See “Note 15. Subsequent Events (Unaudited)” for further details of these redemptions.

Since September 15, 2017, the Company has had the right to redeem all or a portion of the 7.50% Senior Notes at redemption prices decreasing from 101.875% to 100% of the principal amount on September 15, 2018, plus accrued and unpaid interest.

6.25% Senior Notes due 2023. Before April 15, 2018, the Company may, at its option, redeem all or a portion of the 6.25% Senior Notes due 2023 (the “6.25% Senior Notes”) at 100% of the principal amount plus accrued and unpaid interest and a make-whole premium. Thereafter, the Company may redeem all or a portion of the 6.25% Senior Notes at redemption prices decreasing from 104.688% to 100% of the principal amount on April 15, 2021, plus accrued and unpaid interest.

If a Change of Control (as defined in the indentures governing the 8.25% Senior Notes, the 7.50% Senior Notes and the 6.25% Senior Notes) occurs, the Company may be required by holders to repurchase the 8.25% Senior Notes, the 7.50% Senior Notes and the 6.25% Senior Notes for cash at a price equal to 101% of the principal amount purchased, plus any accrued and unpaid interest.

The indentures governing the 8.25% Senior Notes, the 7.50% Senior Notes and the 6.25% Senior Notes contain covenants that, among other things, limit the Company’s ability and the ability of its restricted subsidiaries to: pay distributions on, purchase or redeem the Company’s common stock or other capital stock or redeem the Company’s subordinated debt; make investments; incur or guarantee additional indebtedness or issue certain types of equity securities; create certain liens; sell assets; consolidate, merge or transfer all or substantially all of the Company’s assets; enter into agreements that restrict distributions or other payments from the Company’s restricted subsidiaries to the Company; engage in transactions with affiliates; and create unrestricted subsidiaries. Such indentures governing the Company’s senior notes are also subject to customary events of default, including those related to failure to comply with the terms of the notes and the indenture, certain failures to file reports with the SEC, certain cross defaults of other indebtedness and mortgages and certain failures to pay final judgments. At December 31, 2017, the 8.25% Senior Notes, the 7.50% Senior Notes and the 6.25% Senior Notes are guaranteed by the same subsidiaries that also guarantee the revolving credit facility.

7. Asset Retirement Obligations

The following table sets forth asset retirement obligations for the years ended December 31, 2017 and 2016:

	Years Ended December 31,	
	2017	**2016**
	(In thousands)	
Beginning of year asset retirement obligations	$21,240	$16,511
Liabilities incurred	3,920	2,137
Increase due to acquisition of oil and gas properties	153	2,037
Liabilities settled	(343)	(599)
Reduction due to divestitures of oil and gas properties	(2,671)	—
Accretion expense	1,799	1,364
Revisions to estimated cash flows	(306)	(210)
End of year asset retirement obligations	23,792	21,240
Current asset retirement obligations (included in other current liabilities)	(295)	(392)
Non-current asset retirement obligations	$23,497	$20,848

8. Commitments and Contingencies

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not currently expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

The results of operations and financial position of the Company continue to be affected from time to time in varying degrees by domestic and foreign political developments as well as legislation and regulations pertaining to restrictions on oil and gas production, imports and exports, natural gas regulation, tax legislation, environmental regulations and cancellation of contract rights. Both the likelihood and overall effect of such occurrences on the Company vary greatly and are not predictable.

Rent expense included in general and administrative expense for the years ended December 31, 2017, 2016 and 2015 was $1.7 million, $2.0 million, and $2.2 million, respectively, and includes rent expense for the Company's corporate office and field offices. The table below presents total minimum commitments associated with long-term, non-cancelable operating and capital leases, drilling rig contracts and gathering, processing and transportation service agreements which require minimum volumes of natural gas to be delivered as of December 31, 2017. The total minimum commitments related to the drilling rig contracts represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will generally be billed for their working interest share of such costs.

	2018	2019	2020	2021	2022	2023 and Thereafter	Total
				(In thousands)			
Operating leases	$5,038	$4,895	$4,637	$4,450	$1,854	$—	$20,874
Capital leases	1,823	1,800	1,050	—	—	—	4,673
Drilling rig contracts	23,885	8,881	—	—	—	—	32,766
Delivery commitments	3,657	3,676	2,757	2,438	10	26	12,564
Total	$34,403	$19,252	$8,444	$6,888	$1,864	$26	$70,877

In connection with the ExL Acquisition, the Company has agreed to a contingent payment of $50.0 million per year if crude oil prices exceed specified thresholds for each of the years of 2018 through 2021 with a cap of $125.0 million, which is not included in the table above.

Contractual Obligations Executed Subsequent to December 31, 2017

In January and February 2018, the Company extended two of its drilling rig contracts for terms of one and two years. The gross contractual obligations for these extended drilling rig contracts are approximately $22.2 million. Additionally, in January and February 2018, the Company entered into four produced water disposal contracts for terms between five and six years, which require delivery of minimum volumes. The gross contractual obligations for these new produced water disposal contracts, which reflect the aggregate undiscounted deficiency fees assuming no delivery of any produced water, are approximately $111.6 million. The gross contractual obligations associated with these drilling rig and produced water disposal contracts are not included in the table above as they were entered into subsequent to December 31, 2017.

9. Preferred Stock and Warrants

On June 28, 2017, the Company entered into a Preferred Stock Purchase Agreement with certain funds managed or sub-advised by GSO Capital Partners LP and its affiliates (the "GSO Funds") to issue and sell in a private placement (i) $250.0 million initial liquidation preference (250,000 shares) of 8.875% redeemable preferred stock, par value $0.01 per share (the "Preferred Stock") and (ii) warrants for 2,750,000 shares of the Company's common stock, with a term of ten years and an exercise price of $16.08 per share, exercisable only on a net share settlement basis (the "Warrants"), for a cash purchase price equal to $970.00 per share of Preferred Stock. The Company paid the GSO Funds $5.0 million as a commitment fee upon signing the Preferred Stock Purchase Agreement. The closing of the private placement occurred on August 10, 2017, contemporaneously with the closing of the ExL Acquisition. The Company used the net proceeds of approximately $236.4 million, net of issuance costs to fund a portion of the purchase price for the ExL Acquisition and for general corporate purposes. The Company also entered into a registration rights agreement with the GSO Funds at the closing of the private placement, which provided certain registration and other rights for the benefit of the GSO Funds. During the fourth quarter of 2017, the Company filed a registration statement with the SEC to register the resale of the Preferred Stock and the common stock that may be issued in respect of the Preferred Stock and that underlie the Warrants. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for further details of the ExL Acquisition.

The Preferred Stock has a liquidation preference of $1,000.00 per share and bears an annual cumulative dividend rate of 8.875%, payable on March 15, June 15, September 15 and December 15 of any given year. The Company may elect to pay all or a portion of the Preferred Stock dividends in shares of its common stock in decreasing percentages as follows with respect to any dividend declared by the Company's Board of Directors and paid in respect of a quarter ending:

Period	Percentage
On or after December 15, 2017 and on or prior to September 15, 2018	100%
On or after December 15, 2018 and on or prior to September 15, 2019	75%
On or after December 15, 2019 and on or prior to September 15, 2020	50%

If the Company fails to satisfy the Preferred Stock dividend on the applicable dividend payment date, then the unpaid dividend will be added to the liquidation preference until paid.

The Preferred Stock outstanding is not mandatorily redeemable, but can be redeemed at the Company's option and, in certain circumstances, at the option of the holders of the Preferred Stock. On or prior to August 10, 2018, the Company had the right to redeem up to 50,000 shares of Preferred Stock, in cash, at $1,000.00 per share, plus accrued and unpaid dividends in an amount not to exceed the sum of the cash proceeds of divestitures of oil and gas properties and related assets, the sale or issuance of the Company's common stock and the sale of any of the Company's wholly owned subsidiaries. On January 24, 2018, the Company redeemed 50,000 shares of Preferred Stock for $50.5 million with a portion of the proceeds from the divestitures of oil and gas properties. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for further details of the divestitures of oil and gas properties.

In addition, at any time on or prior to August 10, 2020, the Company may redeem all or part of the Preferred Stock in cash at a redemption premium of 104.4375%, plus accrued and unpaid dividends and the present value on the redemption date of all quarterly dividends that would be payable from the redemption date through August 10, 2020. After August 10, 2020, the Company may redeem all or part of the Preferred Stock in cash at redemption premiums, as presented in the table below, plus accrued but unpaid dividends.

Period	Percentage
After August 10, 2020 but on or prior to August 10, 2021	104.4375%
After August 10, 2021 but on or prior to August 10, 2022	102.21875%
After August 10, 2022	100%

The holders of the Preferred Stock have the option to cause the Company to redeem the Preferred Stock under the following conditions:

- Upon the Company's failure to pay a quarterly dividend within three months of the applicable payment date;
- On or after August 10, 2024, if the Preferred Stock remain outstanding; or
- Upon the occurrence of certain changes of control

For the first two conditions described above, the Company has the option to settle any such redemption in cash or shares of its common stock and the holders of the Preferred Stock may elect to revoke or reduce the redemption if the Company elects to settle in shares of common stock.

The Preferred Stock are non-voting shares except as required by the Company's articles of incorporation or bylaws. However, so long as the GSO Funds beneficially own more than 50% of the Preferred Stock, the consent of the holders of the Preferred Stock will be required prior to issuing stock senior to or on parity with the Preferred Stock, incurring indebtedness subject to a leverage ratio, agreeing to certain restrictions on dividends on, or redemption of, the Preferred Stock and declaring or paying dividends on the Company's common stock in excess of $15.0 million per year subject to a leverage ratio. Additionally, if the Company does not redeem the Preferred Stock before August 10, 2024, in connection with a change of control or failure to pay a quarterly dividend within three months of the applicable payment date, the holders of the Preferred Stock are entitled to additional rights including:

- Increasing the dividend rate to 12.0% per annum until August 10, 2024 and thereafter to the greater of 12.0% per annum and the one-month LIBOR plus 10.0%;
- Causing the election of up to two directors to the Company's Board of Directors; and
- Requiring approval by the holders of the Preferred Stock to incur indebtedness subject to a leverage ratio, declaring or paying dividends on the Company's common stock in excess of $15.0 million per year or issuing equity of the Company's subsidiaries to third parties.

The table below summarizes Preferred Stock activity for the year ended December 31, 2017:

	December 31, 2017
For the Year Ended December 31, 2017	
Preferred Stock, beginning of period	$—
Relative fair value of Preferred Stock at issuance	213,400
Accretion of discount on Preferred Stock	862
Preferred Stock, end of period	$214,262

Net proceeds were allocated between the Preferred Stock and the Warrants based on their relative fair values at the issuance date, with $213.4 million allocated to the Preferred Stock and $23.0 million allocated to the Warrants. The fair value of the Preferred Stock was calculated by a third-party valuation specialist using a discounted cash flow model. Significant inputs into the calculation of the Preferred Stock included the per share cash purchase price, redemption premiums, and liquidation preference, all as discussed above, as well as redemption assumptions provided by the Company. The fair value of the Warrants was calculated using a Black-Scholes-Merton option pricing model, incorporating the following assumptions at the issuance date:

	Issuance Date Fair Value Assumptions
Exercise price	$16.08
Expected term (in years)	10.0
Expected volatility	62.9%
Risk-free interest rate	2.2%
Dividend yield	—%

See “Note 12. Fair Value Measurements” for further discussion of the significant inputs used in the Preferred Stock and Warrants fair value calculations.

Preferred Stock Dividends and Accretion

For the year ended December 31, 2017, the Company declared and paid an aggregate of $7.8 million of dividends, in cash, to the holders of record of the Preferred Stock on September 1, 2017 and December 1, 2017.

For the year ended December 31, 2017, the Company recorded accretion of the Preferred Stock of $0.9 million, which is presented with the dividends in the consolidated statements of operations.

10. Shareholders’ Equity and Stock Based Compensation

Increase in Authorized Common Shares

At the Company’s annual meeting of shareholders on May 16, 2017, shareholders approved an amendment to the Company’s Amended and Restated Articles of Incorporation to increase the number of authorized shares of common stock from 90,000,000 to 180,000,000.

Sale of Common Stock

On July 3, 2017, the Company completed a public offering of 15.6 million shares of its common stock at a price per share of $14.28. The Company used the net proceeds of $222.4 million, net of offering costs, to fund a portion of the purchase price of the ExL Acquisition and for general corporate purposes. See “Note 3. Acquisitions and Divestitures of Oil and Gas Properties” for further details of the ExL Acquisition.

On October 28, 2016, the Company completed a public offering of 6.0 million shares of its common stock at a price per share of $37.32. The Company used the net proceeds of $223.7 million, net of offering costs, to fund the Sanchez Acquisition and repay borrowings under the revolving credit facility. See “Note 3. Acquisitions and Divestitures of Oil and Gas Properties” for further details of the ExL Acquisition.

On October 21, 2015, the Company completed a public offering of 6.3 million shares of its common stock at a price per share of $37.80. The Company used the net proceeds of $238.8 million, net of offering costs, to repay borrowings under the Company’s revolving credit facility and for general corporate purposes.

On March 20, 2015, the Company completed a public offering of 5.2 million shares of its common stock at a price per share of $44.75. The Company used the net proceeds of $231.3 million, net of offering costs, to repay a portion of the borrowings under the Company’s revolving credit facility and for general corporate purposes.

Stock-Based Compensation

At the Company's annual meeting of shareholders on May 16, 2017, shareholders approved the 2017 Incentive Plan of Carrizo Oil & Gas, Inc. (the "2017 Incentive Plan"), which replaced the Incentive Plan of Carrizo Oil & Gas, Inc., as amended and restated effective May 15, 2014 (the "Prior Incentive Plan"). From the effective date of the 2017 Incentive Plan, no further awards may be granted under the Prior Incentive Plan, however, awards previously granted under the Prior Incentive Plan will remain outstanding in accordance with their terms. The 2017 Incentive Plan provides that up to 2,675,000 shares of the Company's common stock, plus the shares remaining available for awards under the Prior Incentive Plan, may be issued.

As of December 31, 2017, there were 1,750,908 common shares remaining available for grant under the 2017 Incentive Plan. Each restricted stock award, restricted stock unit, or performance share granted under the 2017 Incentive Plan counts as 1.35 shares while a stock option or stock-settled stock appreciation right granted under the 2017 Incentive Plan counts as 1.00 share against the number of common shares available for grant under the 2017 Incentive Plan.

Restricted Stock Awards and Units. Restricted stock awards can be granted to employees and independent contractors and restricted stock units can be granted to employees, independent contractors, and non-employee directors. As of December 31, 2017, unrecognized compensation costs related to unvested restricted stock awards and units was $21.3 million and will be recognized over a weighted average period of 1.9 years.

The table below summarizes restricted stock award and unit activity for the years ended December 31, 2017, 2016 and 2015:

	Restricted Stock Awards and Units	Weighted Average Grant Date Fair Value
For the Year Ended December 31, 2015		
Unvested restricted stock awards and units, beginning of period	1,335,682	$34.55
Granted	401,421	$51.45
Vested	(671,417)	$32.96
Forfeited	(23,689)	$43.36
Unvested restricted stock awards and units, end of period	1,041,997	$44.22
For the Year Ended December 31, 2016		
Unvested restricted stock awards and units, beginning of period	1,041,997	$44.22
Granted	887,254	$27.80
Vested	(811,136)	$36.32
Forfeited	(6,405)	$34.46
Unvested restricted stock awards and units, end of period	1,111,710	$36.93
For the Year Ended December 31, 2017		
Unvested restricted stock awards and units, beginning of period	1,111,710	$36.93
Granted	1,020,465	$25.63
Vested	(635,965)	$39.62
Forfeited	(13,555)	$29.11
Unvested restricted stock awards and units, end of period	1,482,655	$28.07

The aggregate fair value of restricted stock awards and units that vested during the years ended December 31, 2017, 2016 and 2015 was $20.3 million, $26.3 million and $32.0 million, respectively.

Stock Appreciation Rights ("SARs"). SARs can be granted to employees and independent contractors under the Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan ("Cash SAR Plan") or the 2017 Incentive Plan. SARs granted under the 2017 Incentive Plan can be settled in shares of common stock or cash, at the option of the Company, while SARs granted under the Cash SAR Plan may only be settled in cash. All outstanding SARs have been granted under the Cash SAR Plan and therefore will be settled solely in cash. The grant date fair value of SARs is calculated using the Black-Scholes-Merton option pricing model. The liability for SARs as of December 31, 2017 was $4.4 million, all of which was classified as "Other liabilities" in the consolidated balance sheets. As of December 31, 2016, the liability for SARs was $11.5 million, of which $10.0 million was classified as "Other current liabilities," with the remaining $1.5 million classified as "Other liabilities" in the consolidated balance sheets. Unrecognized compensation costs related to unvested SARs was $1.3 million as of December 31, 2017, and will be recognized over a weighted average period of 1.1 years.

The table below summarizes the activity for SARs for the years ended December 31, 2017, 2016 and 2015:

	Stock Appreciation Rights	Weighted Average Exercise Prices	Weighted Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)	Aggregate Intrinsic Value of Exercises (In millions)
For the Year Ended December 31, 2015					
Outstanding, beginning of period	765,198	$22.49			
Granted	—	—			
Exercised	(64,745)	$29.40			$1.5
Forfeited	—	—			
Outstanding, end of period	700,453	$21.86			
Vested, end of period	626,661	$21.05			
Vested and exercisable, end of period	626,661	$21.05			
For the Year Ended December 31, 2016					
Outstanding, beginning of period	700,453	$21.86			
Granted	376,260	27.30			
Exercised	(354,075)	$23.89			$5.2
Forfeited	—	—			
Outstanding, end of period	722,638	$23.69			
Vested, end of period	350,840	$19.87			
Vested and exercisable, end of period	350,840	$19.87			
For the Year Ended December 31, 2017					
Outstanding, beginning of period	722,638	$23.69			
Granted	342,440	$26.94			
Exercised	(219,279)	$17.28			$2.1
Forfeited	—	—			
Expired	(131,561)	$24.19			
Outstanding, end of period	714,238	$27.12	3.7	$—	
Vested, end of period	185,899	$27.30			
Vested and exercisable, end of period	—	$27.30	3.2	$—	

No SARs were granted during the year ended December 31, 2015. The following table summarizes the assumptions used to calculate the grant date fair value of SARs granted during the years ended December 31, 2017 and 2016:

	Years Ended December 31,	
	2017	2016
Expected term (in years)	4.24	3.93
Expected volatility	54.3%	45.1%
Risk-free interest rate	1.8%	1.3%
Dividend yield	—%	—%

Performance Shares. The Company can grant performance shares to employees and independent contractors, where each performance share represents the right to receive one share of common stock. The number of performance shares that will vest ranges from zero to 200% of the target performance shares granted based on the total shareholder return ("TSR") of the Company's common stock relative to the TSR achieved by a specified industry peer group over an approximate three year performance period, the last day of which is also the vesting date. The grant date fair value of the performance awards is calculated using a Monte Carlo simulation. As of December 31, 2017, unrecognized compensation costs related to unvested performance shares was $2.1 million and will be recognized over a weighted average period of 1.7 years.

The table below summarizes performance share activity for the years ended December 31, 2017, 2016 and 2015:

	Target Performance Shares [1]	Weighted Average Grant Date Fair Value
For the Year Ended December 31, 2015		
Unvested performance shares, beginning of period	56,342	$68.15
Granted	56,517	$65.51
Vested	—	—
Forfeited	—	—
Unvested performance shares, end of period	112,859	$66.83
For the Year Ended December 31, 2016		
Unvested performance shares, beginning of period	112,859	$66.83
Granted	41,651	$35.71
Vested	—	—
Forfeited	—	—
Unvested performance shares, end of period	154,510	$58.44
For the Year Ended December 31, 2017		
Unvested performance shares, beginning of period	154,510	$58.44
Granted	46,787	$35.14
Vested	(56,342)	$68.15
Forfeited	—	—
Unvested performance shares, end of period	144,955	$47.14

(1) The number of shares of common stock issued upon vesting may vary from the number of target performance shares depending on the Company's final TSR ranking for the approximate three year performance period.

During the first quarter of 2017, the Company issued 92,200 shares of common stock for 56,342 target performance shares that vested during the first quarter of 2017 with a multiplier of 164% based on the Company's final TSR ranking during the performance period.

The following table summarizes the assumptions used to calculate the grant date fair value of the performance shares granted during the years ended December 31, 2017, 2016 and 2015:

	Years Ended December 31,		
	2017	2016	2015
Number of simulations	500,000	500,000	500,000
Expected term (in years)	2.98	3.01	2.89
Expected volatility	59.2%	55.3%	45.3%
Risk-free interest rate	1.5%	1.2%	0.9%
Dividend yield	—%	—%	—%

Stock-Based Compensation Expense, Net. Stock-based compensation expense associated with restricted stock awards and units, stock appreciation rights to be settled in cash and performance shares is reflected as general and administrative expense, net of amounts capitalized to oil and gas properties in the consolidated statements of operations.

The Company recognized the following stock-based compensation expense, net for the periods indicated:

	Years Ended December 31,		
	2017	2016	2015
		(In thousands)	
Restricted stock awards and units	$21,372	$28,196	$23,668
Stock appreciation rights	(5,023)	9,675	(6,326)
Performance shares	2,442	2,806	1,961
	18,791	40,677	19,303
Less: amounts capitalized to oil and gas properties	(4,482)	(4,591)	(4,574)
Total stock-based compensation expense, net	$14,309	$36,086	$14,729

11. Derivative Instruments

Commodity Derivative Instruments

The Company uses commodity derivative instruments to reduce its exposure to commodity price volatility for a portion of its forecasted crude oil, NGL, and natural gas production and thereby achieve a more predictable level of cash flows to support the Company's drilling, completion, and infrastructure capital expenditure program. The Company does not enter into derivative instruments for speculative or trading purposes. The Company's commodity derivative instruments consist of fixed price swaps, basis swaps, three-way collars and purchased and sold call options, which are described below.

Fixed Price Swaps: The Company receives a fixed price and pays a variable market price to the counterparties over specified periods for contracted volumes.

Basis Swaps: The Company receives a variable NYMEX settlement price, plus or minus a fixed differential price, and pays a variable published index price to the counterparties over specified periods for contracted volumes.

Three-Way Collars: A three-way collar is a combination of options including a purchased put option (fixed floor price), a sold call option (fixed ceiling price) and a sold put option (fixed sub-floor price). These contracts offer a higher fixed ceiling price relative to a costless collar but limit the Company's protection from decreases in commodity prices below the fixed floor price. At settlement, if the market price is between the fixed floor price and the fixed sub-floor price or is above the fixed ceiling price, the Company receives the fixed floor price or pays the market price, respectively. If the market price is below the fixed sub-floor price, the Company receives the market price plus the difference between the fixed floor price and the fixed sub-floor price. If the market price is between the fixed floor price and fixed ceiling price, no payments are due from either party. The Company has incurred premiums on certain of these contracts in order to obtain a higher floor price and/or ceiling price.

Sold Call Options: These contracts give the counterparties the right, but not the obligation, to buy contracted volumes from the Company over specified periods and prices in the future. At settlement, if the market price exceeds the fixed price of the call option, the Company pays the counterparty the excess. If the market price settles below the fixed price of the call option, no payment is due from either party. These contracts require the counterparties to pay premiums to the Company that represent the fair value of the call option as of the date of purchase.

Purchased Call Options: These contracts give the Company the right, but not the obligation, to buy contracted volumes from the counterparties over specified periods and prices in the future. At settlement, if the market price exceeds the fixed price of the call option, the counterparties pay the Company the excess. If the market price settles below the fixed price of the call option, no payment is due from either party. These contracts require the Company to pay premiums to the counterparties that represent the fair value of the call option as of the date of purchase.

All of the Company's purchased call options were executed contemporaneously with sales of call options to increase the fixed price on a portion of the existing sold call options and therefore are presented on a net basis in the "Net Sold Call Options" table below.

Premiums: In order to increase the fixed price on a portion of the Company's existing sold call options, as mentioned above, the Company incurred premiums on its purchased call options. Additionally, the Company has incurred premiums on certain of its three-way collars in order to obtain a higher floor price and/or ceiling price. The payment of premiums associated with the Company's purchased call options and certain of the three-way collars are deferred until the applicable contracts settle on a monthly basis. When the Company has entered into three-way collars which span multiple years, the Company has elected to defer payment of certain of the premiums until the final year's contracts settle on a monthly basis.

The following tables set forth a summary of the Company's outstanding derivative positions at weighted average contract prices as of December 31, 2017:

Crude Oil Fixed Price Swaps

Period	Volumes (Bbls/d)	NYMEX Price ($/Bbl)
FY 2018	6,000	$49.55

Crude Oil Basis Swaps

Period	Volumes (Bbls/d)	LLS-NYMEX Price Differential ($/Bbl)
FY 2018	6,000	$2.91

Period	Volumes (Bbls/d)	Midland-NYMEX Price Differential ($/Bbl)
FY 2018	6,000	($0.10)

Crude Oil Three-Way Collars

Period	Volumes (Bbls/d)	NYMEX Prices Sub-Floor Price ($/Bbl)	Floor Price ($/Bbl)	Ceiling Price ($/Bbl)
FY 2018	24,000	$39.38	$49.06	$60.14
FY 2019	12,000	$40.00	$48.40	$60.29

Crude Oil Net Sold Call Options

Period	Volumes (Bbls/d)	NYMEX Ceiling Price ($/Bbl)
FY 2018	3,388	$71.33
FY 2019	3,875	$73.66
FY 2020	4,575	$75.98

NGL Fixed Price Swaps

	OPIS Purity Ethane Mont Belvieu Non-TET		OPIS Propane Mont Belvieu Non-TET		OPIS Normal Butane Mont Belvieu Non-TET		OPIS Isobutane Mont Belvieu Non-TET		OPIS Natural Gasoline Mont Belvieu Non-TET	
Period	Volumes (Bbls/d)	Price ($/Bbl)	Volumes (Bbls/d)	Price ($/Bbl)	Volumes (Bbls/d)	Price ($/Bbl)	Volumes (Bbls/d)	Price ($/Bbl)	Volumes (Bbls/d)	Price ($/Bbl)
FY 2018	2,200	$12.01	1,500	$34.23	200	$38.85	600	$38.98	600	$55.23

Natural Gas Sold Call Options

Period	Volumes (MMBtu/d)	NYMEX Ceiling Price ($/MMBtu)
FY 2018	33,000	$3.25
FY 2019	33,000	$3.25
FY 2020	33,000	$3.50

The Company typically has numerous hedge positions that span several time periods and often result in both fair value derivative asset and liability positions held with that counterparty. The Company nets its derivative instrument fair values executed with the same counterparty, along with deferred premium obligations, to a single asset or liability pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract.

Counterparties to the Company's derivative instruments who are also lenders under the Company's credit agreement allow the Company to satisfy any need for margin obligations associated with derivative instruments where the Company is in a net liability position with its counterparties with the collateral securing the credit agreement, thus eliminating the need for independent collateral posting. Counterparties who are not lenders under the Company's credit agreement can require derivative contracts to be novated to a lender if the net liability position exceeds the Company's unsecured credit limit with that counterparty and therefore do not require the posting of cash collateral.

Because the counterparties have investment grade credit ratings, or the Company has obtained guarantees from the applicable counterparty's investment grade parent company, the Company believes it does not have significant credit risk and accordingly does not currently require its counterparties to post collateral to support the net asset positions of its derivative instruments. Although the Company does not currently anticipate nonperformance from its counterparties, it continually monitors the credit ratings of its counterparties and its counterparty's parent company, as applicable.

Contingent Consideration

As part of the ExL Acquisition, the Company agreed to the Contingent ExL Consideration that will require payment of $50.0 million per year for each of the years of 2018 through 2021, with a cap of $125.0 million, if the EIA WTI average price is greater than $50.00 per barrel for the respective year. As of December 31, 2017, the estimated fair value of the Contingent ExL Consideration was $85.6 million and was classified as non-current "Derivative liabilities" in the consolidated balance sheets.

As part of the divestiture of the Company's Utica assets, the Company agreed to the Contingent Utica Consideration in which the Company will receive $5.0 million per year for each of the years of 2018 through 2020, if the EIA WTI average price is greater than $50.00, $53.00, and $56.00 for the years of 2018, 2019, and 2020, respectively. The Company recorded the Contingent Utica Consideration at its divestiture date fair value of $6.1 million in the consolidated financial statements. As of December 31, 2017, the estimated fair value of the Contingent Utica Consideration was $8.0 million and was classified as non-current "Other assets" in the consolidated balance sheets.

As part of the divestiture of the Company's Marcellus assets, the Company agreed to the Contingent Marcellus Consideration in which the Company will receive $3.0 million per year for each of the years of 2018 through 2020, with a cap of $7.5 million, if the CME HH average price is greater than $3.13, $3.18, and $3.30 for the years of 2018, 2019, and 2020, respectively. The Company recorded the Contingent Marcellus Consideration at its divestiture date fair value of $2.7 million in the consolidated financial statements. As of December 31, 2017, the estimated fair value of the Contingent Marcellus Consideration was $2.2 million and was classified as non-current "Other assets" in the consolidated balance sheets.

The following table summarizes the combined contingent consideration recorded in the consolidated financial statements:

	Consolidated Balance Sheets		Consolidated Statements of Operations
	December 31, 2017		Year Ended December 31, 2017
	Other Assets - Non-Current	Derivative Liabilities - Non-Current	(Gain) Loss on Derivatives, Net
		(In thousands)	
Contingent ExL Consideration	$—	($85,625)	$33,325
Contingent Utica Consideration	7,985	—	(1,840)
Contingent Marcellus Consideration	2,205	—	455
Contingent consideration	$10,190	($85,625)	$31,940

Subsequent to December 31, 2017, the Company closed on the sale of substantially all of its assets in the Niobrara Formation. As part of the divestiture, the Company agreed to the Contingent Niobrara Consideration. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for further details.

Derivative Assets and Liabilities

All derivative instruments are recorded in the consolidated balance sheets as either an asset or liability measured at fair value. The deferred premium obligations associated with the Company's commodity derivative instruments are recorded in the period in which they are incurred and are netted with the commodity derivative instrument fair value asset or liability pursuant to the netting arrangements described above. The combined derivative instrument fair value assets and liabilities, including deferred premium obligations, recorded in the consolidated balance sheets as of December 31, 2017 and 2016 are summarized below:

	December 31, 2017		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
		(In thousands)	
Commodity derivative instruments	$4,869	($4,869)	$—
Deferred premium obligations	—	—	—
Other current assets	$4,869	($4,869)	$—
Commodity derivative instruments	9,505	(9,505)	—
Deferred premium obligations	—	—	—
Contingent consideration	10,190	—	10,190
Other assets-non current	$19,695	($9,505)	$10,190
Commodity derivative instruments	($52,671)	$4,869	($47,802)
Deferred premium obligations	(9,319)	—	(9,319)
Derivative liabilities-current	($61,990)	$4,869	($57,121)
Commodity derivative instruments	(24,609)	9,505	(15,104)
Deferred premium obligations	(11,603)	—	(11,603)
Contingent consideration	(85,625)	—	(85,625)
Derivative liabilities-non current	($121,837)	$9,505	($112,332)

	December 31, 2016		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
		(In thousands)	
Commodity derivative instruments	$7,990	($6,753)	$1,237
Deferred premium obligations	—	—	—
Other current assets	$7,990	($6,753)	$1,237
Commodity derivative instruments	3,882	(3,882)	—
Deferred premium obligations	—	—	—
Contingent consideration	—	—	—
Other assets-non current	$3,882	($3,882)	$—
Commodity derivative instruments	($27,346)	$6,753	($20,593)
Deferred premium obligations	(2,008)	—	(2,008)
Derivative liabilities-current	($29,354)	$6,753	($22,601)
Commodity derivative instruments	(28,841)	3,882	(24,959)
Deferred premium obligations	(2,569)	—	(2,569)
Contingent consideration	—	—	—
Derivative liabilities-non current	($31,410)	$3,882	($27,528)

See "Note 12. Fair Value Measurements" for additional details regarding the fair value of the Company's derivative instruments.

(Gain) Loss on Derivatives, Net

The Company has elected not to meet the criteria to qualify its commodity derivative instruments for hedge accounting treatment. Therefore, all gains and losses as a result of changes in the fair value of the Company's commodity derivative instruments and contingent consideration are recognized as (gain) loss on derivatives, net in the consolidated statements of operations in the period in which the changes occur. All deferred premium obligations associated with the Company's commodity derivative instruments are recognized in (gain) loss on derivatives, net in the consolidated statements of operations in the period in which the deferred premium obligations are incurred. The effect of derivative instruments and deferred premium obligations in the consolidated statements of operations for the years ended December 31, 2017, 2016, and 2015 is summarized below:

	Years Ended December 31,		
	2017	2016	2015
		(In thousands)	
(Gain) Loss on Derivatives, Net			
Crude oil	$22,839	$23,609	($99,624)
Natural gas liquids	1,322	—	—
Natural gas	(15,399)	19,584	(4,063)
Deferred premium obligations incurred	18,401	5,880	4,426
Contingent consideration	31,940	—	—
Total (Gain) Loss on Derivatives, Net	$59,103	$49,073	($99,261)

Cash Received (Paid) for Derivative Settlements, Net

Cash flows are impacted to the extent that settlements under these contracts, including deferred premium obligations paid, result in payments to or receipts from the counterparty during the period and are presented as cash received (paid) for derivative settlements, net in the consolidated statements of cash flows. The effect of commodity derivative instruments and deferred premium obligations in the consolidated statements of cash flows for the years ended December 31, 2017, 2016, and 2015 is summarized below:

	Years Ended December 31,		
	2017	**2016**	**2015**
		(In thousands)	
Cash Received (Paid) for Derivative Settlements, Net			
Crude oil	$9,883	$125,098	$176,511
Natural gas	(54)	—	17,785
Deferred premium obligations paid	(2,056)	(5,729)	—
Total Cash Received (Paid) for Derivative Settlements, Net	$7,773	$119,369	$194,296

12. Fair Value Measurements

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 – Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 – Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3 – Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables summarize the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2017 and 2016:

	December 31, 2017		
	Level 1	**Level 2**	**Level 3**
		(In thousands)	
Derivative instrument assets	$—	$—	$10,190
Derivative instrument liabilities	$—	($62,906)	($85,625)

	December 31, 2016		
	Level 1	**Level 2**	**Level 3**
		(In thousands)	
Derivative instrument assets	$—	$1,237	$—
Derivative instrument liabilities	$—	($45,552)	$—

The derivative asset and liability fair values reported in the consolidated balance sheets are as of the balance sheet date and subsequently change as a result of changes in commodity prices, market conditions and other factors.

Commodity derivative instruments. The fair value of the Company's commodity derivative instruments is based on a third-party industry-standard pricing model which uses contract terms and prices and assumptions and inputs that are substantially observable in active markets throughout the full term of the instruments including forward oil and gas price curves, discount rates and volatility factors and are therefore designated as Level 2 within the valuation hierarchy. The fair values are also compared to the values provided by the counterparties for reasonableness and are adjusted for the counterparties' credit quality for derivative assets and the Company's credit quality for derivative liabilities.

The Company typically has numerous hedge positions that span several time periods and often result in both fair value derivative asset and liability positions held with that counterparty. Deferred premium obligations are netted with the fair value derivative asset and liability positions, which are all offset to a single asset or liability, at the end of each reporting period. The Company nets the fair values of its derivative assets and liabilities associated with commodity derivative instruments executed with the same counterparty, along with deferred premium obligations, pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The Company had no transfers into Level 1 and no transfers into or out of Level 2 for the years ended December 31, 2017 and 2016.

Contingent consideration. The fair values of the Contingent ExL Consideration, the Contingent Utica Consideration and the Contingent Marcellus Consideration were determined by a third-party valuation specialist using Monte Carlo simulations including significant inputs such as future commodity prices, volatility factors for the future commodity prices and a risk adjusted discount rate. As some of these assumptions are not observable throughout the full term of the contingent consideration, the contingent consideration was designated as Level 3 within the valuation hierarchy. The Company reviewed the valuations, including the related inputs, and analyzed changes in fair value measurements between periods.

The following tables present reconciliations of changes in the fair values of the financial assets and liabilities related to the Company's contingent consideration, which were designated as Level 3 within the valuation hierarchy, for the year ended December 31, 2017:

	Year Ended December 31, 2017
	(In thousands)
Fair value assets, beginning of period	$—
Recognition of acquisition date fair value	8,805
Gain (loss) on changes in fair value(1)	1,385
Transfers into (out of) Level 3	—
Fair value assets, end of period	$10,190

	Year Ended December 31, 2017
	(In thousands)
Fair value liability, beginning of period	$—
Recognition of acquisition date fair value	(52,300)
Gain (loss) on changes in fair value(1)	(33,325)
Transfers into (out of) Level 3	—
Fair value liability, end of period	($85,625)

(1) Included in (gain) loss on derivatives, net in the consolidated statements of operations.

See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" and "Note 11. Derivative Instruments" for further details regarding the contingent consideration.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

The fair value measurements of assets acquired and liabilities assumed, other than contingent consideration which is discussed above, are measured as of the acquisition date by a third-party valuation specialist using a discounted cash flow model based on inputs that are not observable in the market and therefore designated as Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimated volumes of oil and gas reserves, production rates, future commodity prices, timing of development, future operating and development costs and a risk adjusted discount rate. See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for further details of the assets acquired and liabilities assumed as of the acquisition dates for the ExL Acquisition and Sanchez Acquisition.

The fair value measurements of asset retirement obligations are measured as of the date a well is drilled or when production equipment and facilities are installed using a discounted cash flow model based on inputs that are not observable in the market and therefore are designated as Level 3 inputs. Significant inputs to the fair value measurement of asset retirement obligations include estimates of the costs of plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land as well as estimates of the economic lives of the oil and gas wells and future inflation rates. See "Note 7. Asset Retirement Obligations" for additional details regarding the Company's asset retirement obligations for the years ended December 31, 2017 and 2016.

The fair value measurements of the Preferred Stock are measured as of the issuance date by a third-party valuation specialist using a discounted cash flow model based on inputs that are not observable in the market and therefore are designated as Level 3 inputs.

Significant inputs to the valuation of the Preferred Stock include the per share cash purchase price, redemption premiums, liquidation preference, and redemption assumptions provided by the Company. See "Note 9. Preferred Stock and Warrants" for details regarding the allocation of the net proceeds based on the relative fair values of the Preferred Stock and Warrants.

Fair Value of Other Financial Instruments

The Company's other financial instruments consist of cash and cash equivalents, receivables, payables, and long-term debt, which are designated as Level 1 under the fair value hierarchy. The carrying amounts of cash and cash equivalents, receivables, and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The carrying amount of long-term debt associated with borrowings outstanding under the Company's revolving credit facility approximates fair value as borrowings bear interest at variable rates. The following table presents the carrying amounts of the Company's senior notes and other long-term debt, net of unamortized premiums and debt issuance costs, with the fair values measured using quoted secondary market trading prices.

	December 31, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
7.50% Senior Notes due 2020 [1]	$446,087	$459,518	$593,447	$624,750
6.25% Senior Notes due 2023	641,792	674,375	640,546	672,750
8.25% Senior Notes due 2025	245,605	274,375	—	—
Other long-term debt due 2028	4,425	4,445	4,425	4,419

(1) The Company delivered additional notices of redemption to the trustee for its 7.50% Senior Notes subsequent to December 31, 2017.

13. Condensed Consolidating Financial Information

The rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries and consolidated basis and should be read in conjunction with the consolidated financial statements. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had such guarantor subsidiaries operated as independent entities.

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(In thousands)

	December 31, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$3,441,633	$105,533	$—	($3,424,288)	$122,878
Total property and equipment, net	5,953	2,630,707	3,028	(3,878)	2,635,810
Investment in subsidiaries	(999,793)	—	—	999,793	—
Other assets	9,270	10,346	—	—	19,616
Total Assets	$2,457,063	$2,746,586	$3,028	($2,428,373)	$2,778,304
Liabilities and Shareholders' Equity					
Current liabilities	$165,701	$3,631,401	$3,028	($3,427,308)	$372,822
Long-term liabilities	1,689,466	114,978	—	15,879	1,820,323
Preferred stock	214,262	—	—	—	214,262
Total shareholders' equity	387,634	(999,793)	—	983,056	370,897
Total Liabilities and Shareholders' Equity	$2,457,063	$2,746,586	$3,028	($2,428,373)	$2,778,304

	December 31, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$2,735,830	$63,513	$—	($2,726,355)	$72,988
Total property and equipment, net	42,181	1,503,695	3,800	(3,916)	1,545,760
Investment in subsidiaries	(1,282,292)	—	—	1,282,292	—
Other assets	7,423	156	—	—	7,579
Total Assets	$1,503,142	$1,567,364	$3,800	($1,447,979)	$1,626,327
Liabilities and Shareholders' Equity					
Current liabilities	$114,805	$2,822,729	$3,800	($2,729,375)	$211,959
Long-term liabilities	1,348,105	26,927	—	15,878	1,390,910
Preferred stock	—	—	—	—	—
Total shareholders' equity	40,232	(1,282,292)	—	1,265,518	23,458
Total Liabilities and Shareholders' Equity	$1,503,142	$1,567,364	$3,800	($1,447,979)	$1,626,327

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(In thousands)

	Year Ended December 31, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$302	$745,586	$—	$—	$745,888
Total costs and expenses	195,728	459,057	—	(37)	654,748
Income (loss) from continuing operations before income taxes	(195,426)	286,529	—	37	91,140
Income tax expense	—	(4,030)	—	—	(4,030)
Equity in income of subsidiaries	282,499	—	—	(282,499)	—
Income from continuing operations	$87,073	$282,499	$—	($282,462)	$87,110
Income from discontinued operations, net of income taxes	—	—	—	—	—
Net income	$87,073	$282,499	$—	($282,462)	$87,110
Dividends on preferred stock	(7,781)	—	—	—	(7,781)
Accretion on preferred stock	(862)	—	—	—	(862)
Net income attributable to common shareholders	$78,430	$282,499	$—	($282,462)	$78,467

	Year Ended December 31, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$482	$443,112	$—	$—	$443,594
Total costs and expenses	208,054	910,522	—	492	1,119,068
Loss from continuing operations before income taxes	(207,572)	(467,410)	—	(492)	(675,474)
Income tax benefit	—	—	—	—	—
Equity in loss of subsidiaries	(467,410)	—	—	467,410	—
Loss from continuing operations	($674,982)	($467,410)	$—	$466,918	($675,474)
Income from discontinued operations, net of income taxes	—	—	—	—	—
Net loss	($674,982)	($467,410)	$—	$466,918	($675,474)
Dividends on preferred stock	—	—	—	—	—
Accretion on preferred stock	—	—	—	—	—
Net loss attributable to common shareholders	($674,982)	($467,410)	$—	$466,918	($675,474)

	Year Ended December 31, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$1,708	$427,495	$—	$—	$429,203
Total costs and expenses	95,464	1,603,515	—	28,984	1,727,963
Loss from continuing operations before income taxes	(93,756)	(1,176,020)	—	(28,984)	(1,298,760)
Income tax benefit	10,125	127,010	—	3,740	140,875
Equity in loss of subsidiaries	(1,049,010)	—	—	1,049,010	—
Loss from continuing operations	($1,132,641)	($1,049,010)	$—	$1,023,766	($1,157,885)
Income from discontinued operations, net of income taxes	2,731	—	—	—	2,731
Net loss	($1,129,910)	($1,049,010)	$—	$1,023,766	($1,155,154)
Dividends on preferred stock	—	—	—	—	—
Accretion on preferred stock	—	—	—	—	—
Net loss attributable to common shareholders	($1,129,910)	($1,049,010)	$—	$1,023,766	($1,155,154)

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($121,107)	$544,088	$—	$—	$422,981
Net cash used in investing activities from continuing operations	(615,364)	(1,155,340)	—	611,252	(1,159,452)
Net cash provided by financing activities from continuing operations	741,817	611,252	—	(611,252)	741,817
Net cash used in discontinued operations	—	—	—	—	—
Net increase in cash and cash equivalents	5,346	—	—	—	5,346
Cash and cash equivalents, beginning of year	4,194	—	—	—	4,194
Cash and cash equivalents, end of year	$9,540	$—	$—	$—	$9,540

	Year Ended December 31, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($34,773)	$307,541	$—	$—	$272,768
Net cash used in investing activities from continuing operations	(312,291)	(575,824)	(740)	269,023	(619,832)
Net cash provided by financing activities from continuing operations	308,340	268,283	740	(269,023)	308,340
Net cash used in discontinued operations	—	—	—	—	—
Net decrease in cash and cash equivalents	(38,724)	—	—	—	(38,724)
Cash and cash equivalents, beginning of year	42,918	—	—	—	42,918
Cash and cash equivalents, end of year	$4,194	$—	$—	$—	$4,194

	Year Ended December 31, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities from continuing operations	$2,655	$376,080	$—	$—	$378,735
Net cash used in investing activities from continuing operations	(447,296)	(674,758)	—	448,678	(673,376)
Net cash provided by financing activities from continuing operations	480,767	298,678	—	(448,678)	330,767
Net cash used in discontinued operations	(4,046)	—	—	—	(4,046)
Net increase in cash and cash equivalents	32,080	—	—	—	32,080
Cash and cash equivalents, beginning of year	10,838	—	—	—	10,838
Cash and cash equivalents, end of year	$42,918	$—	$—	$—	$42,918

14. Supplemental Cash Flow Information

Supplemental cash flow disclosures and non-cash investing and financing activities are presented below:

	Years Ended December 31,		
	2017	2016	2015
	(In thousands)		
Supplemental cash flow disclosures:			
Cash paid for interest, net of amounts capitalized	$77,213	$75,231	$64,692
Cash paid for income taxes	—	—	—
Non-cash investing and financing activities:			
Increase (decrease) in capital expenditure payables and accruals	$102,272	($21,492)	($86,878)
Contingent consideration related to acquisitions of oil and gas properties	52,300	—	—
Contingent consideration related to divestitures of oil and gas properties	(8,805)	—	—
Liabilities assumed in connection with the Sanchez Acquisition	—	4,880	—
Stock-based compensation expense capitalized to oil and gas properties	4,482	4,591	4,574
Asset retirement obligations capitalized to oil and gas properties	3,726	1,927	4,853

15. Subsequent Events (Unaudited)

Divestitures

Niobrara. On January 19, 2018, the Company closed the sale of substantially all of its assets in the Niobrara Formation. The Company has received net cash proceeds of approximately $136.6 million, subject to post-closing adjustments, which includes a deposit received upon the execution of the purchase and sale agreement and amounts received at closing.

Eagle Ford. On January 31, 2018, the Company closed the sale of a portion of its assets in the Eagle Ford Shale to EP Energy E&P Company, L.P. The Company has received net cash proceeds of approximately $246.2 million, subject to post-closing adjustments, which includes a deposit received upon the execution of the purchase and sale agreement and amounts received at the initial closing as well as a subsequent closing for leases that were not conveyed at the initial closing.

See "Note 3. Acquisitions and Divestitures of Oil and Gas Properties" for further details regarding these divestitures.

Redemptions of 7.50% Senior Notes due 2020

On January 19, 2018, the Company delivered a notice of redemption to the trustee for its 7.50% Senior Notes to call for redemption on February 18, 2018, $100.0 million aggregate principal amount of the outstanding 7.50% Senior Notes. On February 20, 2018, the Company paid an aggregate redemption price of $105.1 million, which included a redemption premium of $1.9 million as well as accrued and unpaid interest of $3.2 million from the last interest payment date up to, but not including, the redemption date.

On January 31, 2018, the Company delivered a notice of redemption to the trustee for its 7.50% Senior Notes to call for redemption on March 2, 2018, $220.0 million aggregate principal amount of the outstanding 7.50% Senior Notes. On the redemption date, the Company expects to pay an aggregate redemption price of $231.8 million, which includes a redemption premium of $4.1 million as well as accrued and unpaid interest of $7.7 million from the last interest payment date up to, but not including, the redemption date.

Redemption of Preferred Stock

On January 19, 2018, the Company provided a notice to be delivered to the holders of its Preferred Stock under which it called for redemption of 50,000 of the shares of Preferred Stock, representing 20% of the issued and outstanding Preferred Stock, on January 24, 2018. The Company paid $50.5 million on January 24, 2018 upon redemption, which consisted of $1,000.00 per share of Preferred Stock redeemed, plus accrued and unpaid dividends.

Senior Secured Revolving Credit Facility

On January 31, 2018, as a result of the divestiture in the Eagle Ford Shale discussed above, the Company's borrowing base under the Senior Secured Revolving Credit Facility was reduced from $900.0 million to $830.0 million, however, the elected commitment amount remained unchanged at $800.0 million.

Hedging

In January 2018, the Company entered into the following natural gas derivative positions at the weighted average contract prices summarized below:

Natural Gas Fixed Price Swaps

Period	Volumes (MMBtu/d)	NYMEX Price ($/MMBtu)
March 2018 - December 2018	25,000	$3.01

16. Supplemental Disclosures about Oil and Gas Producing Activities (Unaudited)

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities are summarized below:

	Years Ended December 31,		
	2017	2016	2015
		(In thousands)	
Property acquisition costs			
Proved properties	$303,307	$90,661	$—
Unproved properties	525,061	113,535	63,446
Total property acquisition costs	828,368	204,196	63,446
Exploration costs	91,098	37,508	117,227
Development costs	569,982	374,134	389,396
Total costs incurred	$1,489,448	$615,838	$570,069

Costs incurred exclude capitalized interest on unproved properties of $28.3 million, $17.0 million, and $32.1 million for the years ended December 31, 2017, 2016 and 2015, respectively. Included in exploration and development costs are non-cash additions related to the estimated future asset retirement obligations of the Company's oil and gas properties of $3.5 million, $1.9 million and $4.9 million for the years ended December 31, 2017, 2016 and 2015, respectively. Non-cash additions related to the estimated future asset retirement obligations associated with the ExL Acquisition of $0.1 million and for the Sanchez Acquisition of $2.0 million are included in acquisition costs of proved properties for the year ended December 31, 2017 and 2016, respectively. The internal cost of employee compensation and benefits, including stock-based compensation, capitalized to proved or unproved oil and gas properties of $14.8 million, $10.5 million and $15.8 million for the years ended December 31, 2017, 2016 and 2015, respectively, are included in exploration, development and unproved property acquisition costs.

Proved Oil and Gas Reserve Quantities

Proved oil and gas reserves are generally those quantities of crude oil, NGLs and natural gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and government regulations. Proved developed reserves include reserves that can be expected to be produced through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Proved undeveloped reserves include reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved reserve quantities at December 31, 2017, 2016, and 2015 and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company, L.P. Such estimates have been prepared in accordance with guidelines established by the SEC. All of the Company's proved reserves are attributable to properties within the United States.

The Company's proved reserves and changes in proved reserves are as follows:

	Crude Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Proved Reserves (MBoe)
Proved reserves:				
January 1, 2015	100,704	13,513	221,017	151,053
Extensions and discoveries	26,358	5,292	33,925	37,304
Revisions of previous estimates	(9,059)	2,768	11,808	(4,323)
Production	(8,415)	(1,352)	(21,812)	(13,402)
December 31, 2015	109,588	20,221	244,938	170,632
Extensions and discoveries	40,074	8,612	59,318	58,572
Revisions of previous estimates	(16,731)	(3,230)	1,481	(19,713)
Purchases of reserves in place	4,810	122	7,282	6,145
Production	(9,423)	(1,788)	(25,574)	(15,473)
December 31, 2016	128,318	23,937	287,445	200,163
Extensions and discoveries	50,476	13,781	98,980	80,754
Revisions of previous estimates	(19,838)	(909)	27,774	(16,118)
Purchases of reserves in place	21,634	8,642	94,962	46,103
Sales of reserves in place	(650)	(526)	(170,219)	(29,546)
Production	(12,566)	(2,327)	(28,472)	(19,639)
December 31, 2017	167,374	42,598	310,470	261,717
Proved developed reserves:				
December 31, 2014	35,238	5,294	149,697	65,482
December 31, 2015	42,311	7,933	154,725	76,032
December 31, 2016	51,062	9,387	187,054	91,625
December 31, 2017	69,632	17,447	131,355	108,972
Proved undeveloped reserves:				
December 31, 2014	65,466	8,219	71,320	85,571
December 31, 2015	67,277	12,288	90,213	94,600
December 31, 2016	77,256	14,550	100,391	108,538
December 31, 2017	97,742	25,151	179,115	152,745

Extensions and discoveries

For the year ended December 31, 2017, the Company added 6,473 MBoe of proved developed reserves and 74,281 MBoe of proved undeveloped reserves through its drilling program and associated offset locations. Eagle Ford and Delaware Basin comprised 51% and 48%, respectively, of the total extensions and discoveries.

For the year ended December 31, 2016, the Company added 6,525 MBoe of proved developed reserves and 52,047 MBoe of proved undeveloped reserves through its drilling program and associated offset locations. Eagle Ford and Delaware Basin comprised 79% and 20%, respectively, of the total extensions and discoveries.

For the year ended December 31, 2015, the Company added 5,237 MBoe of proved developed reserves and 32,067 MBoe of proved undeveloped reserves through its drilling program and associated offset locations. Eagle Ford comprised 89% of the total extensions and discoveries.

Revisions of previous estimates

For the year ended December 31, 2017, revisions of previous estimates reduced the Company's proved reserves by 16,118 MBoe. Included in revisions of previous estimates were:

- Positive revisions due to price of 2,684 MBoe.
- Negative revisions due to performance of 4,500 MBoe primarily in the Eagle Ford due to a downward shift of the type curve for certain PUD locations partially offset by positive revisions due to well performance in Marcellus which occurred prior to the sale in November 2017.
- Negative revisions in proved undeveloped reserves of 14,302 MBoe in the Eagle Ford due to changes in the Company's previously approved development plan which resulted in the timing of development for certain PUD locations to move beyond five years from initial booking. The drivers of the changes in the Company's previously approved development plan were the recent ExL Acquisition and the move to a more efficient development plan which includes drilling and completing larger pads.

For the year ended December 31, 2016, revisions of previous estimates reduced the Company's proved reserves by 19,713 MBoe. Included in revisions of previous estimates were:

- Negative revisions due to price of 6,705 MBoe primarily due to the decline in the 12-Month Average Realized price for crude oil, of which 3,228 MBoe related to proved developed and proved undeveloped locations that were no longer economic and 3,477 MBoe related to reductions in the level of economic reserves in proved developed and proved undeveloped reserve locations due to loss of tail reserves;
- Negative revisions due to performance of 6,083 MBoe primarily in Eagle Ford as the EURs for certain PUD locations were reduced as a result of tighter spacing and shorter lateral lengths partially offset by positive revisions in Marcellus;
- Negative revisions in proved undeveloped reserves of 6,925 MBoe in the Eagle Ford due to changes in the Company's previously approved development plan which resulted in the timing of development for certain PUD locations to move beyond five years from initial booking. The drivers of the changes in the Company's previously approved development plan were the move to a more efficient development plan which includes drilling and completing larger pads and the recent Sanchez Acquisition.

For the year ended December 31, 2015, revisions of previous estimates reduced the Company's proved reserves by 4,323 MBoe. Included in revisions of previous estimates were:

- Negative revisions due to price of 15,846 MBoe primarily due to the decline in the 12-Month Average Realized price for crude oil, of which 6,208 MBoe related to proved developed and proved undeveloped locations that were no longer economic and 9,638 MBoe related to reductions in the level of economic reserves in proved developed and proved undeveloped reserve locations resulting in shorter economic lives;
- Positive revisions due to performance of 11,523 MBoe are primarily in Eagle Ford and Marcellus.

Purchases of reserves in place

For the year ended December 31, 2017, purchases of reserves in place included 26,009 MBoe of proved developed reserves and 20,094 MBoe of proved undeveloped reserves associated with the ExL Acquisition.

For the year ended December 31, 2016, purchases of reserves in place included 4,978 MBoe of proved developed reserves and 1,167 MBoe of proved undeveloped reserves associated with the Sanchez Acquisition.

There were no purchases of reserves in place for the year ended December 31, 2015.

Sales of reserves in place

For the year ended December 31, 2017, sales of reserves in place included 22,249 MBoe of proved developed reserves and 7,297 MBoe of proved undeveloped reserves associated with the Marcellus Shale and Utica Shale divestitures.

There were no sales of reserves in place for the years ended December 31, 2016 and 2015.

Standardized Measure

The standardized measure of discounted future net cash flows relating to proved reserves is as follows:

	December 31,		
	2017	**2016**	**2015**
		(In thousands)	
Future cash inflows	$10,109,752	$5,903,629	$5,878,348
Future production costs	(3,202,201)	(2,241,928)	(2,124,059)
Future development costs	(1,699,909)	(1,264,493)	(1,178,773)
Future income taxes (1)	(445,056)	—	—
Future net cash flows	4,762,586	2,397,208	2,575,516
Less 10% annual discount to reflect timing of cash flows	(2,297,544)	(1,093,779)	(1,210,292)
Standard measure of discounted future net cash flows	$2,465,042	$1,303,429	$1,365,224

(1) Future income taxes in the calculation of the standardized measure of discounted future net cash flows were zero as of December 31, 2016 and 2015, as the historical tax basis of proved oil and gas properties, net operating loss carryforwards, and future tax deductions exceeded the undiscounted future net cash flows before income taxes of the Company's proved oil and gas reserves as of December 31, 2016 and 2015.

Proved reserve estimates and future cash flows are based on the average realized prices for sales of crude oil, NGLs and natural gas on the first calendar day of each month during the year. The average realized prices used for 2017, 2016 and 2015 were $49.87, $39.60, and $47.24 per Bbl, respectively, for crude oil, $19.78, $11.66 and $12.00 per Bbl, respectively, for NGLs, and $2.96, $1.89 and $1.87 per Mcf, respectively, for natural gas.

Future operating and development costs are computed primarily by the Company's petroleum engineers by estimating the expenditures to be incurred in developing and producing the Company's proved reserves at the end of the year, based on current costs and assuming continuation of existing economic conditions. Future income taxes, which include the effects of the Tax Cuts and Jobs Act, are based on current statutory rates, adjusted for the tax basis of oil and gas properties and available applicable tax assets. A discount factor of 10% was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair value of the Company's oil and gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in proved reserve estimates.

Changes in Standardized Measure

Changes in the standardized measure of discounted future net cash flows relating to proved reserves are summarized below:

	Years Ended December 31,		
	2017	2016	2015
		(In thousands)	
Standardized measure at beginning of year	$1,303,429	$1,365,224	$2,555,082
Revisions to reserves proved in prior years:			
Net change in sales prices and production costs related to future production	$710,773	($346,763)	($2,547,213)
Net change in estimated future development costs	(51,854)	74,407	342,238
Net change due to revisions in quantity estimates	(42,214)	(150,245)	(157,271)
Accretion of discount	130,343	136,522	326,074
Changes in production rates (timing) and other	(116,056)	(111,137)	(139,533)
Total revisions to reserves proved in prior years	630,992	(397,216)	(2,175,705)
Net change due to extensions and discoveries, net of estimated future development and production costs	597,502	313,201	252,155
Net change due to purchases of reserves in place	452,932	43,426	—
Net change due to divestitures of reserves in place	(106,608)	—	—
Sales of crude oil, NGLs and natural gas produced, net of production costs	(566,258)	(320,272)	(312,213)
Previously estimated development costs incurred	326,383	299,066	340,247
Net change in income taxes	(173,330)	—	705,658
Net change in standardized measure of discounted future net cash flows	1,161,613	(61,795)	(1,189,858)
Standardized measure at end of year	$2,465,042	$1,303,429	$1,365,224

17. Quarterly Financial Data (Unaudited)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2017 and 2016:

Year Ended December 31, 2017	First Quarter	Second Quarter	Third Quarter [2]	Fourth Quarter [3]
	(In thousands, except per share data)			
Total revenues	$151,355	$166,483	$181,279	$246,771
Operating profit [1]	$57,953	$63,147	$69,364	$113,205
(Gain) loss on derivatives, net	($25,316)	($26,065)	$24,377	$86,107
Net income (loss)	$40,021	$56,306	$7,823	($17,040)
Net income (loss) attributable to common shareholders	$40,021	$56,306	$5,574	($23,434)
Net income (loss) attributable to common shareholders per common share [3]				
Basic	$0.61	$0.86	$0.07	($0.29)
Diluted	$0.61	$0.85	$0.07	($0.29)

Year Ended December 31, 2016	First Quarter [4]	Second Quarter [4]	Third Quarter [4]	Fourth Quarter
	(In thousands, except per share data)			
Total revenues	$81,262	$107,324	$111,177	$143,831
Operating profit (loss) [1]	($7,491)	$27,167	$31,634	$55,000
Net loss	($311,395)	($262,126)	($101,174)	($779)
Net loss attributable to common shareholders	($311,395)	($262,126)	($101,174)	($779)
Net loss attributable to common shareholders per common share [3]				
Basic	($5.34)	($4.46)	($1.72)	($0.01)
Diluted	($5.34)	($4.46)	($1.72)	($0.01)

(1) Total revenues less lease operating expense, production taxes, ad valorem taxes and DD&A.

(2) Third quarter of 2017 included the following:

a. $2.2 million of Preferred Stock dividends which reduced net income attributable to common shareholders.

(3) Fourth quarter of 2017 included the following:

a. $4.2 million loss on extinguishment of debt as a result of the redemption of $150.0 million aggregate principal amount of 7.50% Senior Notes.

b. $5.5 million of Preferred Stock dividends which increased net loss attributable to common shareholders.

(4) The sum of quarterly net income (loss) attributable to common shareholders per common share does not agree with the total year net income (loss) attributable to common shareholders per common share as each computation is based on the weighted average of common shares outstanding during the period.

(5) In the first quarter, second quarter, and third quarter of 2016, the Company recognized impairments of proved oil and gas properties of $274.4 million, $197.1 million, and $105.1 million, respectively.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CARRIZO OIL & GAS, INC.

By: /s/ David L. Pitts
David L. Pitts
Vice President and Chief Financial Officer

Date: February 28, 2018

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

Name	Capacity	Date
/s/ S.P. Johnson IV **S. P. Johnson IV**	President, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2018
/s/ David L. Pitts **David L. Pitts**	Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2018
/s/ Gregory F. Conaway **Gregory F. Conaway**	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 28, 2018
/s/ Steven A. Webster **Steven A. Webster**	Chairman of the Board	February 28, 2018
/s/ Thomas L. Carter, Jr. **Thomas L. Carter, Jr.**	Director	February 28, 2018
/s/ Robert F. Fulton **Robert F. Fulton**	Director	February 28, 2018
/s/ F. Gardner Parker **F. Gardner Parker**	Director	February 28, 2018
/s/ Roger A. Ramsey **Roger A. Ramsey**	Director	February 28, 2018
/s/ Frank A. Wojtek **Frank A. Wojtek**	Director	February 28, 2018

COMPANY INFORMATION

OFFICERS

S.P. JOHNSON, IV
President and Chief Executive Officer

BRAD FISHER
Vice President and Chief Operating Officer

DAVID L. PITTS
Vice President and Chief Financial Officer

RICHARD H. SMITH
Vice President of Land

GERALD A. MORTON
Vice President and General Counsel

GREGORY F. CONAWAY
Vice President and Chief Accounting Officer

DIRECTORS

STEVEN A. WEBSTER
Chairman of the Board

THOMAS L. CARTER, JR.
President, Chairman, and Chief Executive Officer
Black Stone Minerals, L.P.

ROBERT F. FULTON
Retired

S.P. JOHNSON, IV
President and Chief Executive Officer

F. GARDNER PARKER
Lead Independent Director

ROGER A. RAMSEY
Retired

FRANK A. WOJTEK
President and Director of
A-Texian Compressor, Inc.

BUSINESS DEVELOPMENT

ANDREW R. AGOSTO
Vice President of Business Development

JAMES K. PRITTS
Vice President of Business Development

GARY W. UHLAND
Vice President of Business Development

INVESTOR RELATIONS

JEFFREY P. HAYDEN, CFA
Vice President of Investor Relations

GENERAL COUNSEL

GERALD A. MORTON
General Counsel and
Vice President of Business Development

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Ernst & Young LLP
5 Houston Center
1401 McKinney Street, Suite 1200
Houston, TX 77010
Phone: 713.750.1500

TRANSFER AGENT

EQ Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120-4101
Phone: 1.800.468.9716

CARRIZO

COMMON STOCK
The Company's common stock trades on the NASDAQ Global Select Market and is quoted under the symbol CRZO. As of February 23, 2018, the number of shares outstanding of the Company's common stock was 81,469,593.

ANNUAL MEETING

May 22, 2018, at 9:00am CDT
Heritage Plaza - The Plaza Conference Room
1111 Bagby Street
1st Floor
Houston, TX 77002

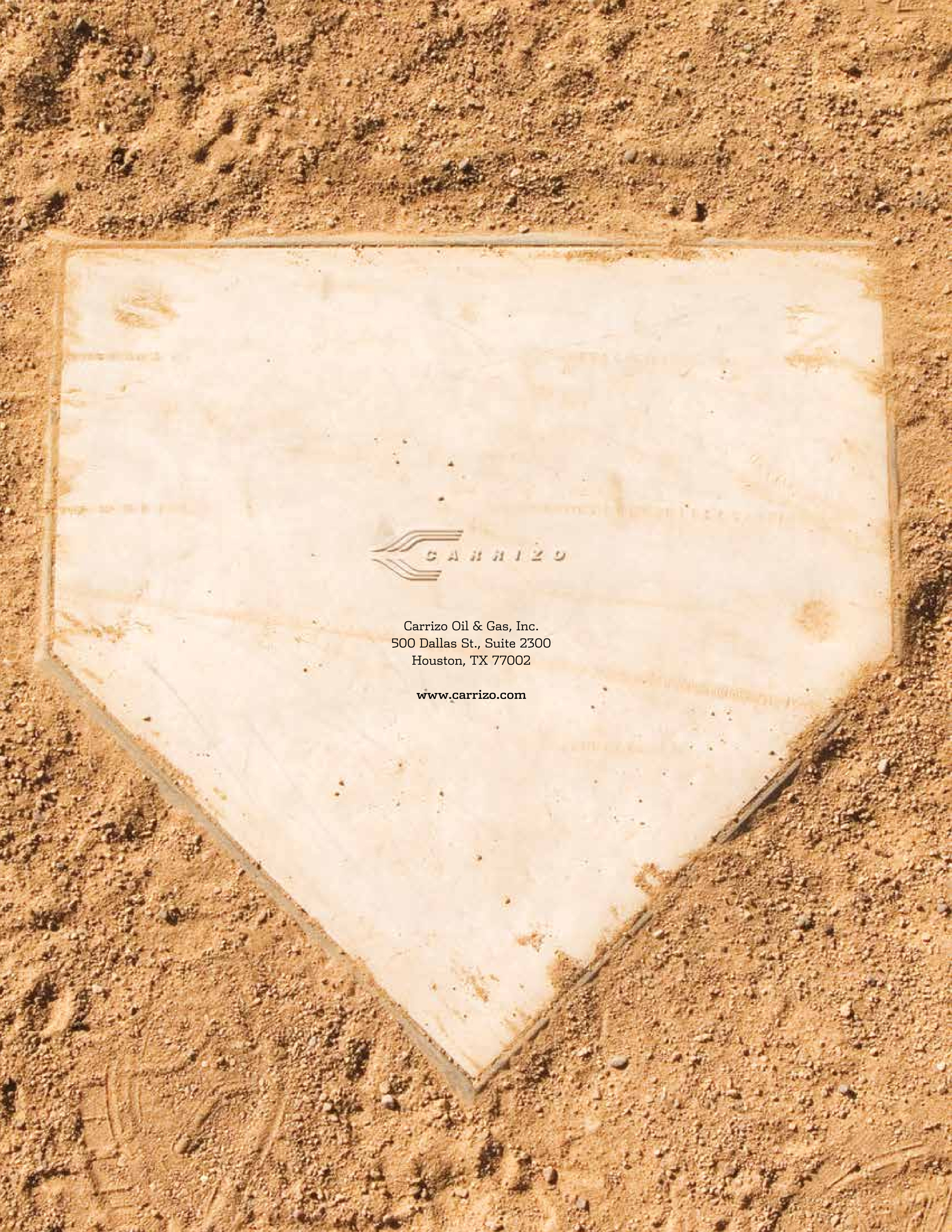
CARRIZO OIL & GAS, INC.

500 Dallas St., Suite 2300
Houston, TX 77002
Phone: 713.328.1000
Fax: 713.358.6437
Website: www.carrizo.com

FORWARD LOOKING STATEMENTS

Any statement herein that is not a historical fact is a forward-looking statement. These projections and statements reflect the Company's current views with respect to future events and financial performance. No assurances can be given, however, that these events will occur or that these projections will be achieved; and actual results may differ materially from those projected as a result of certain factors, including those described in Risk Factors and other sections in the attached Form 10-K and the Company's other SEC filings.

Back row (left to right): Chip Johnson, Jeff Hayden, Gary Uhland, Dick Smith, Greg Conaway, Doug Reid, Rex Bigler, Andy Agosto, Brad Fisher
Front row (left to right): Greg Percival, Jim Pritts, JP Breaux, Scott Hudson, Shaleen Patel, David Pitts, Laura Kinningham, Gerry Morton



CARRIZO

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