CARRIZO OIL & GAS INC
Form 10-K
February 27, 2017

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, 2016
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 þ 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 þ
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 þ 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 þ 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES ¨ NO þ
At June 30, 2016, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $2.0 billion based on the closing price of such stock on such date of $35.85.

At February 24, 2017, the number of shares outstanding of the registrant's Common Stock was 65,140,971.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2017 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, 2016.

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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,” “sc 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

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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 oil and gas primarily from resource plays located in the United States. Our current operations are principally focused in proven, producing oil and gas plays primarily in the Eagle Ford Shale in South Texas, the Delaware Basin in West Texas, the Niobrara Formation in Colorado, the Utica Shale in Ohio, and the Marcellus Shale in Pennsylvania.

Crude oil production in 2016 was 25,745 Bbls/d, an increase of 12% as compared to 23,054 Bbls/d in 2015, primarily driven by strong performance from our wells in the Eagle Ford. We achieved this despite an 18% decrease in drilling and completion capital expenditures in 2016 as compared to 2015. Total production in 2016 increased to 42,276 Boe/d from 36,719 Boe/d in 2015 primarily due to production from our wells in the Eagle Ford and Delaware Basin.

At year-end 2016, our proved reserves of 200.2 MMBoe were 64% crude oil, 12% natural gas liquids and 24% natural gas. Our reserves increased 29.6 MMBoe from our year-end 2015 proved reserves of 170.6 MMBoe primarily as a result of our ongoing drilling program in the Eagle Ford and the Delaware Basin and the Sanchez Acquisition described below. The following is a summary of the Company’s proved reserves as of December 31, 2016 and 2015. See “—Additional Oil and Gas Disclosures—Proved Oil and Gas Reserves” for further details of our proved reserves.

	Proved Reserves	
	December 31, 2016	December 31, 2015
Region	(MMBoe)	
Eagle Ford	162.3	144.0
Delaware Basin	11.7	1.0
Niobrara	2.7	3.9
Marcellus	21.8	19.8
Utica and other	1.7	1.9
Total	200.2	170.6

Our 2017 capital expenditure plan currently includes $530.0 million to $550.0 million for drilling and completion and $20.0 million for leasehold and seismic. This plan incorporates an assumed increase in oilfield service costs during the year and should allow the Company to run three rigs in the Eagle Ford during the year as well as continue to develop its acreage in the Delaware Basin. We intend to finance our 2017 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 2016 and our planned capital expenditures for 2017:

	Capital Expenditures	
	2017 Plan	2016 Actual
	(In millions)	
Drilling and completion		
Eagle Ford	$485.0	$334.5
Delaware Basin	40.0	47.2
All other regions	15.0	24.2
Total drilling and completion [(1)]	540.0	405.9
Leasehold and seismic [(2)]	20.0	26.4
Total [(3)]	$560.0	$432.3

(1)

Represents the midpoint of our 2017 drilling and completion capital expenditure plan of $530.0 million to $550.0 million.

(2) Our 2016 actual leasehold and seismic capital expenditures and our 2017 leasehold and seismic capital expenditure plan exclude amounts related to the Sanchez Acquisition described below.

(3) Our capital expenditure plan and the capital expenditures included above exclude capitalized general and administrative expense, capitalized interest and capitalized asset retirement obligations.

Business Strategy

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 include:

- Utilize our experience as a technical advantage. We believe we have developed a technical advantage from our extensive experience drilling nearly 900 horizontal wells in various resource plays, including the Eagle Ford, Delaware Basin, Utica, Niobrara, Marcellus, and previously, the Barnett, 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 2017 capital expenditures in the Eagle Ford and, to a lesser extent, the Delaware Basin.
- Pursue opportunities to expand core positions. We pursue a growth strategy in crude oil plays primarily driven by the attractive relative economics associated with our core positions. Nearly 100% of our 2017 drilling and completion capital expenditure plan is directed towards opportunities that we believe are predominantly prospective for crude oil development. 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. Additionally, we continue to take advantage of opportunities to expand our core positions through leasehold acquisitions as evidenced by the Sanchez Acquisition described below.
- Control operating and capital costs. 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, after a substantial reduction in our 2016 capital expenditure plan, we have moderately increased our 2017 capital expenditure plan, in response to a more optimistic outlook in commodity prices.
- 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 sale of assets, proceeds from sales of securities, borrowings under our revolving credit facility and proceeds, payments or carried interest from our joint ventures.
- Manage risk exposure. We seek to limit our financial risks, in part by seeking well-funded partners to ensure that we are able to move forward on projects in a timely manner. We also attempt to limit our exposure to volatility in commodity prices by actively hedging production of crude oil. Our current long-term strategy is to manage exposure to commodity price volatility for a portion of our forecasted crude oil and natural gas production to achieve a more predictable level of cash flows to support current and future capital expenditure plans.

Our Competitive Strengths

We believe we have the following competitive strengths that will support our efforts to successfully execute our business strategy:

- Large inventory of oil-focused drilling locations. We have developed a significant inventory of future oil-focused drilling locations, primarily in our well-established positions in the Eagle Ford, Delaware Basin, Niobrara, and Utica. As of December 31, 2016, we owned leases covering approximately 309,200 gross (179,179 net) acres in these areas. See "—Acreage Data" for further details. Approximately 54% of our estimated proved reserves at December 31, 2016 were undeveloped.
- Operational control. As of December 31, 2016, we operated approximately 94% of the wells in Eagle Ford in which we held an interest. We held an average working interest of approximately 85% 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.

- Successful drilling history. 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.

- Experienced management and professional workforce. Our management has transitioned our focus to oil by entering new plays and completed non-core asset sales. 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.
- Financial flexibility. 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 24, 2017, we had $91.0 million of outstanding borrowings under our $600.0 million revolving credit facility, have no near-term debt maturities, and use commodity derivative instruments to reduce our exposure to commodity price volatility for a portion of our forecasted crude oil and natural gas production. We believe that we have the ability and financial flexibility to fund the planned development of our assets. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources” for further details.

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 3-D survey design parameters and drilling and completion methods. As of December 31, 2016, we operated 667 gross (473.7 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 2016, we operated 100% of the wells drilled in the Eagle Ford where we incurred approximately 82% of our 2016 drilling and completion 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 2016 Proved Reserves, Production and Drilling by Area

	Eagle Ford	Delaware Basin	Niobrara	Marcellus	Utica and other	Total
Proved reserves by product						
Crude oil (MMBbls)	120.9	4.9	2.1	—	0.5	128.4
NGLs (MMBbls)	20.5	2.7	0.3	—	0.4	23.9
Natural gas (Bcf)	125.4	24.8	2.0	130.9	4.4	287.5
Total proved reserves (MMBoe)	162.3	11.7	2.7	21.8	1.7	200.2
Proved reserves by classification (MMBoe)						
Proved developed	63.7	3.4	2.7	20.1	1.7	91.6
Proved undeveloped	98.6	8.3	—	1.7	—	108.6
Total proved reserves	162.3	11.7	2.7	21.8	1.7	200.2
Percent of total reserves	81%	6%	1%	11%	1%	100%
2016 production (MMBoe)	11.2	0.4	1.1	2.3	0.5	15.5
Percent of total production	72%	3%	7%	15%	3%	100%

	Eagle Ford		Delaware Basin		Niobrara		Marcellus		Utica and other		Total	
Operated Well Data	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2016												
Drilled	77	73.1	4	4.0	—	—	—	—	—	—	81	77.1
Brought on production	71	67.0	4	3.9	9	5.2	—	—	—	—	84	76.1
December 31, 2016												
Drilled but uncompleted	35	33.4	2	2.0	—	—	11	4.3	—	—	48	39.7
Producing	446	381.5	6	5.6	130	57.9	81	26.0	4	3.1	667	474.1

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. On December 14, 2016, we completed the acquisition of producing wells and acreage primarily in LaSalle, Frio and McMullen counties from Sanchez Energy Corporation and SN Cotulla Assets, LLC, a subsidiary of Sanchez Energy Corporation ("Sanchez Acquisition") for a purchase price of $181.0 million, subject to purchase price adjustments. The acquisition had an effective date of June 1, 2016. We paid $10.0 million as a deposit on October 24, 2016 and $143.5 million at the initial closing on December 14, 2016, which included purchase price adjustments primarily related to net cash flows from the acquired wells from the effective date to the closing date of $10.7 million and adjustments of $16.8 million for leases not conveyed to us at the initial closing. The acquisition added more than 70 net de-risked drilling locations based on our current development spacing assumptions, which include only a single layer of development within the Lower Eagle Ford Shale, but has upside potential from development of additional zones.

As of December 31, 2016, we held interests in approximately 130,114 gross (100,195 net) acres and were operating two rigs in the Eagle Ford. We currently plan for approximately 90% of our 2017 drilling and completion capital expenditure plan to be directed towards opportunities in the Eagle Ford. During 2016, we began to test various completion optimization techniques, such as tighter frac stage spacing, reducing the stage spacing from 240 ft. to 200 ft. We have been pleased with the early results of this testing and plan to test even tighter frac stage spacing in future Eagle Ford wells.

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, 2016, acres included in the GAIL joint venture cover approximately 25% of our total Eagle Ford acreage.

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, 2016, we held interests in approximately 46,157 gross (21,728 net) acres in the Delaware Basin. During 2016, we drilled 4 gross (4.0 net) wells and completed 4 gross (3.9 net) wells. As we have refined our completion techniques, we have seen improved results. The most recent well brought online was the Fortress State 1H, which achieved a peak 30-day rate of 1,520 Boe/d on a restricted choke. We continue to like the potential of the play and look to expand our acreage over time.

Niobrara Formation

As of December 31, 2016, we held interests in approximately 97,314 gross (31,355 net) acres in the Niobrara, primarily in Weld and Adams counties, Colorado, and were not operating any rigs. During 2016, we did not drill any wells as operator, but completed 9 gross (5.2 net) wells and participated in 22 gross (1.6 net) non-operated wells. We currently expect to continue to participate as a non-operator in high-density projects in the Niobrara, but have no current plans to drill any operated wells in Niobrara in 2017. As a result, we have limited capital allocated to Niobrara as part of our 2017 drilling and completion capital expenditure plan. However, given the improving economics in the play, we will continue to evaluate whether to reallocate a portion of the 2017 drilling and completion capital expenditure plan for further operated development in the latter half of the year.

OIL JV Partners Joint Venture. In October 2012, we completed the sale of a portion of our interests in certain oil and gas properties in the Niobrara to OIL India (USA) Inc. and IOCL (USA) Inc., wholly owned subsidiaries of OIL India Ltd. and Indian Oil Corporation Ltd., respectively. For convenience, in this Annual Report on Form 10-K the term “OIL JV Partners” is used to refer collectively to OIL India (USA) Inc. and IOCL (USA) Inc. We also granted an option in favor of the OIL JV Partners to purchase a 30% share of acreage subsequently acquired by us in specified areas of the play.

Haimo Joint Venture. In December 2012, we completed the sale of an additional portion of our remaining interests in the same oil and gas properties sold to the OIL JV Partners in the transaction described above to Haimo Oil & Gas LLC (“Haimo”), a wholly owned subsidiary of Lanzhou Haimo Technologies Co. Ltd. We also granted an option in favor of Haimo to purchase a 10% share of acreage subsequently acquired by us in the same properties as the OIL JV Partners described above. Following the closing of the Haimo transaction in fourth quarter 2012, the joint venture ownership interests in our Niobrara development activities were 60% Carrizo, 30% OIL JV Partners, and 10% Haimo. We serve as operator of a significant percentage of the properties covered by our Niobrara joint venture arrangements.

Marcellus Shale

As of December 31, 2016, we held interests in approximately 36,293 gross (12,425 net) acres in the Marcellus. We will continue to monitor prices and, consistent with our existing contractual commitments, may increase our activity level and capital expenditures, if natural gas prices so warrant. Our activities in the Marcellus are currently conducted through two joint ventures described below. As of December 31, 2016, we were not operating any rigs in the Marcellus.

Reliance Joint Venture. In September 2010, we completed the sale of 20% of our interests in substantially all of our oil and gas properties in Pennsylvania that had been subject to the Avista Marcellus joint venture described in “Avista Marcellus Joint Venture” below to Reliance Marcellus II, LLC (“Reliance”), a wholly owned subsidiary of Reliance Holding USA, Inc. and an affiliate of Reliance Industries Limited. As described in “Avista Marcellus Joint Venture” below, simultaneously with the closing of our transaction with Reliance, ACP II Marcellus LLC (“ACP II”) closed the sale of its entire interest in the same properties to Reliance. In connection with these sale transactions, we and Reliance also entered into agreements to form a new joint venture with respect to the interests purchased by Reliance from us and ACP II. The joint venture properties are generally held 60% by Reliance and 40% by us.

We have agreed to various restrictions on our ability to transfer our properties covered by the Reliance joint venture. Additionally, we are subject to a mutual right of first offer on direct and indirect property transfers for the remainder of a ten-year development period (through September 2020), subject to specified exceptions. We generally serve as operator of the properties covered by the Reliance joint venture, with Reliance having the right to assume operatorship of 60% of undeveloped acreage in portions of central Pennsylvania.

Avista Marcellus Joint Venture. Effective August 2008, our wholly owned subsidiary Carrizo (Marcellus) LLC entered into a joint venture arrangement with ACP II, an affiliate of Avista Capital Partners, LP, a private equity fund (collectively with ACP II and ACP III Utica LLC (“ACP III”), our joint venture partner in the Utica, “Avista”). In September 2010, we completed the sale of 20% of our interests in substantially all of our oil and gas properties in Pennsylvania that had been subject to the Avista Marcellus joint venture to Reliance as described above under “Reliance Joint Venture.” Simultaneously with the closing of this transaction, ACP II closed the sale of its entire interest in the same properties to Reliance. In connection with these sales transactions, we and

Avista amended the participation agreement and other joint venture agreements with Avista to provide that the properties that we and Avista sold to Reliance, as well as the properties we committed to the new joint venture with Reliance, were no longer subject to the terms of the Avista Marcellus joint venture, and that the Avista Marcellus joint venture's area of mutual interest would generally not include Pennsylvania, the state in which those properties were located. Our Marcellus joint venture with Avista continues and covers acreage primarily in West Virginia and New York. Pursuant to the terms of the amended participation agreement, the areas of mutual interest with Avista have been reduced to specified halos around existing properties in New York and West Virginia. We conducted no material activity under this joint venture during 2016 and do not currently expect to conduct any activity in 2017. For further discussion, see "Note 10. Related Party Transactions" of the Notes to our Consolidated Financial Statements.

Utica Shale

As of December 31, 2016, we held interests in approximately 35,615 gross (25,901 net) acres in the Utica. During 2016, we did not drill or complete any operated wells, but have 16 additional operated wells in inventory where we have drilled and cased the upper portions of such wells. As of December 31, 2016, we were not operating any rigs in the Utica.

Avista Utica Joint Venture. Effective September 2011, our wholly-owned subsidiary, Carrizo (Utica) LLC, entered into a joint venture in the Utica with ACP II, and ACP III. During the term of the Avista Utica joint venture, the joint venture partners acquired and sold acreage and we exercised options under the Avista Utica joint venture agreements to acquire acreage from Avista. The Avista Utica joint venture agreements were terminated on October 31, 2013 in connection with our purchase of certain ACP III assets. After giving effect to this transaction, we and Avista remain working interest partners and we will operate the jointly owned properties which are now subject to standard joint operating agreements. The joint operating agreements with Avista provide for limited areas of mutual interest around our remaining jointly owned acreage.

Steven A. Webster, Chairman of our Board of Directors, serves as Co-Managing Partner and President of Avista Capital Holdings, LP, which has the ability to control Avista and its affiliates. ACP II's and ACP III's Boards of Managers have the sole authority for determining whether, when and to what extent any cash distributions will be declared and paid to members of ACP II or ACP III, respectively. Mr. Webster is not a member of either entity's Board of Managers. As previously disclosed, we have been a party to prior arrangements with affiliates of Avista Capital Holdings LP, including our existing joint venture with Avista in the Marcellus. The terms of the joint ventures with Avista in the Utica and the Marcellus and the related transactions that took place were each separately approved by a special committee of the Company's independent, non-employee directors. See also "Note 10. Related Party Transactions" of the Notes to our Consolidated Financial Statements.

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, 2016 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, 2016, 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, 2016 were based on the average realized prices for sales of crude oil, natural gas liquids and natural gas on the first calendar day of each month during the 12-month period prior to December 31, 2016 ("12-Month Average Realized Price") in accordance with SEC rules and were $39.60 per Bbl of crude oil, $11.66 per Bbl of natural gas liquids and $1.89 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 15. 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, 2016

	Crude Oil	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10

	(MBbls)				(In millions)
Proved developed	51,062	9,387	187,054	91,625	$854.3
Proved undeveloped	77,256	14,550	100,391	108,538	$449.1
Total Proved	128,318	23,937	287,445	200,163	$1,303.4

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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, 2016 (In millions)
Standardized measure of discounted future net cash flows (GAAP)	$1,303.4
Add: present value of future income taxes discounted at 10% per annum (1)	—
PV-10 (Non-GAAP)	$1,303.4

(1) Future income taxes in the calculation of the standardized measure of discounted future net cash flows were zero as of December 31, 2016, 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 our proved oil and gas reserves as of December 31, 2016.

Proved Undeveloped Reserves

The following table provides a summary of the changes in our proved undeveloped reserves (“PUDs”) for the year ended December 31, 2016.

	Crude Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
PUDs as of December 31, 2015	67,277	12,288	90,213	94,600
Extensions and discoveries	36,173	7,555	49,915	52,047
Revisions of previous estimates	(5,981)	(2,414)	(22,959)	(12,221)
Purchases of reserves in place	945	113	656	1,167
Removed due to changes in development plan	(4,901)	(1,007)	(6,105)	(6,925)
Converted to proved developed reserves	(16,257)	(1,985)	(11,329)	(20,130)
PUDs as of December 31, 2016	77,256	14,550	100,391	108,538

Extensions and discoveries of 52.0 MMBoe were due to additional offset locations associated with our drilling program, of which 43.8 MMBoe were in the Eagle Ford. We incurred $48.3 million during 2016 for certain of these PUD locations that were drilled but uncompleted as of December 31, 2016.

Revisions of previous estimates included negative revisions of 4.3 MMBoe due to price, primarily due to the decline in the 12-Month Average Realized Price for crude oil from $47.24 per barrel as of December 31, 2015 to $39.60 per barrel as of December 31, 2016, of which 2.4 MMBoe related to PUD locations that were no longer economic and 1.9 MMBoe related to reductions in the level of economic reserves of PUD locations due to loss of tail reserves. Revisions of previous estimates also included negative revisions due to performance of 7.9 MMBoe primarily as a result of tighter spacing and shorter lateral lengths on certain PUD locations in the Eagle Ford, both of which reduced the estimated ultimate recovery for certain PUD locations.

We removed 6.9 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 move to a more efficient development plan which includes drilling and completing larger pads and the recent Sanchez Acquisition.

We converted 20.1 MMBoe of PUD reserves to proved developed during 2016, of which 19.6 MMBoe were in the Eagle Ford, at a total cost of $277.5 million, or $13.81 per Boe. We also incurred $12.2 million during 2016 on PUD locations that were drilled but uncompleted as of December 31, 2016 that were booked as PUDs as of December 31, 2015.

As of December 31, 2016, we had 17.7 MMBoe of PUD reserves associated with wells that were drilled but uncompleted, of which 16.1 MMBoe are attributable to wells drilled during 2016 and scheduled to be completed in the first half of 2017. The remaining 1.6 MMBoe are attributable to wells scheduled to be completed within five years of their initial booking. We expect to incur $129.5 million of capital expenditures to complete these wells.

At December 31, 2016, 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, 2016, 2015, and 2014 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,		
	2016	2015	2014
Total production volumes -			
Crude oil (MBbls)	9,423	8,415	6,906
NGLs (MBbls)	1,788	1,352	926
Natural gas (MMcf)	25,574	21,812	24,877
Total barrels of oil equivalent (MBoe)	15,473	13,402	11,978
Daily production volumes by product -			
Crude oil (Bbls/d)	25,745	23,054	18,921
NGLs (Bbls/d)	4,885	3,705	2,537
Natural gas (Mcf/d)	69,873	59,758	68,156
Total barrels of oil equivalent per day (Boe/d)	42,276	36,719	32,816
Daily production volumes by region (Boe/d) -			
Eagle Ford	30,664	26,377	21,131
Delaware Basin	1,115	104	10
Niobrara	2,931	2,957	2,585
Marcellus	6,329	5,850	8,354
Utica and other	1,237	1,431	736
Total barrels of oil equivalent (Boe/d)	42,276	36,719	32,816
Average realized prices -			
Crude oil ($ per Bbl)	$40.12	$44.69	$88.40
NGLs ($ per Bbl)	$12.54	$11.54	$27.05
Natural gas ($ per Mcf)	$1.69	$1.72	$3.00
Total average realized price ($ per Boe)	$28.67	$32.03	$59.29
Average production costs ($ per Boe) (1)	$6.38	$6.72	$6.19

(1) 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, 2016, 2015 and 2014. 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,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells - Productive	29	4.5	77	19.5	128	23.0
Exploratory Wells - Nonproductive	—	—	—	—	—	—
Development Wells - Productive	81	73.5	65	55.4	77	63.5
Development Wells - Nonproductive	—	—	—	—	—	—

As of December 31, 2016, we had 48 gross (39.7 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, 2016.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	573	437.1	270	20.4	843	457.5
Natural gas	94	36.6	29	1.4	123	38.0
Total	667	473.7	299	21.8	966	495.5

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped acreage as of December 31, 2016. 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		Percent of Net Undeveloped Acreage Expiring		
	Gross	Net	Gross	Net	Gross	Net	2017	2018	2019
Eagle Ford	93,584	76,026	36,530	24,169	130,114	100,195	42 % (1)	8 % (2)	12 % (2)
Delaware Basin	8,087	5,799	38,070	15,929	46,157	21,728	83 % (3)	5 %	10 %
Niobrara	39,436	14,555	57,878	16,800	97,314	31,355	6 %	8 %	10 %
Marcellus	14,153	5,186	22,140	7,239	36,293	12,425	28 %	42 %	1 %
Utica and other (4)	5,676	4,552	88,103	51,029	93,779	55,581	43 %	11 %	11 %
Total	160,936	106,118	242,721	115,166	403,657	221,284	42 %	11 %	10 %

(1) Of the approximate 10,150 net undeveloped acres scheduled to expire in 2017 in Eagle Ford, approximately 9,150 net undeveloped acres will be held due to development activity or extended by lease extension payments. The remaining net undeveloped acres which are scheduled to expire do not have any associated proved undeveloped reserves.

(2) Proved undeveloped reserves associated with the net undeveloped acres scheduled to expire in 2018 and 2019 are scheduled to be developed prior to the acreage expiration.

(3) In January 2017, we paid to extend approximately 4,000 net undeveloped acres in the Delaware Basin that were scheduled to expire in 2017 and plan on extending the remaining net undeveloped acres scheduled to expire in 2017 either through development activity or lease extension payments.

(4) Other includes non-core acreage principally located in Texas, Colorado, Wyoming, West Virginia, Kentucky, Illinois and New York, where the Company does not currently have planned capital expenditures. There are no costs for unproved property or 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 ten years depending on the area). The percentage of net undeveloped acreage expiring in 2017, 2018, and 2019 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.

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Marketing

Typically, our oil and gas 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 (such as Houston Ship Channel, Dominion Transmission, Texas Eastern Zone M-2, Tennessee Gas Pipeline Zone 4-300, and Transco Leidy Hub) 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 oil and gas 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” 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 (including Colorado and Ohio) 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. Some of the delay in bringing our natural gas to market has been the lack of available pipeline systems in the Marcellus and Utica, particularly those that would take natural gas production from the lease to existing infrastructure. In order to partly alleviate this issue, in the past, certain of our wholly owned subsidiaries have constructed non-jurisdictional gathering facilities in cases where we have determined that we can construct those facilities more quickly or more efficiently than waiting on an unrelated third-party pipeline company.

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 natural gas liquids 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 natural gas liquids 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%. A pipeline trade association advocated a higher percentage adjustment and filed a petition for review of the FERC's December 2015 indexing order with the D.C. Circuit, which is now pending before the court. The currently effective annual index adjustment may be impacted by the outcome of that appeal. 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 and is scheduled to make attainment/nonattainment designations for the revised ozone standards by October 1, 2017. 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 natural gas liquids 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. More recently, 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 has also announced that it intends to impose methane emission standards for existing sources and has issued information collection requests for oil and natural gas facilities. 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. Compliance with these requirements 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 Indiana Bat and 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 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. Most recently 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.

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 years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
	2016	2015	2014
Shell Trading (US) Company	56%	65%	44%
Flint Hills Resources, LP [(1)]	15%	9%	26%

(1) Revenues from this customer were below 10% during 2015.

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, 2016, we had 227 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 Us—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.

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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 natural gas liquids, which represents the approximate energy content of oil, condensate and natural gas liquids 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 natural gas liquids, which represents the approximate energy content of oil, condensate and natural gas liquids 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 continued 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, are 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 early 2017 and most would not be economical at the commodity price lows seen in early 2016. In particular, wells drilled on our acreage in the Utica and Marcellus are not expected to be profitable if prices decrease from the more recent higher prices. 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 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, including prevailing and anticipated prices for oil and gas and the availability and prices of drilling rigs and crews; 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. 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

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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, 2016, approximately 54% of our proved reserves were proved undeveloped. Moreover, some of the producing wells included in our reserve reports as of December 31, 2016 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, 2016, 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 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. In addition, the sustained low oil and gas prices and volatility in oil and gas prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. Some of these working interest owners have experienced 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 or term assignments on our undeveloped properties expire and we are unable to renew the leases, we will lose our right to develop the related properties. The primary term of the leases for a majority of our acreage that is not currently held by production will expire at the end of 2018 if such leases are not extended. 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. 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 of the Marcellus 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 Marcellus and 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.

Production in the Marcellus and Utica by oil and gas companies expanded over the last few years and the amount of natural gas currently being produced by us and others exceeds the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. It is necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for the Marcellus and Utica may not occur for lack of financing or regulatory approvals. In addition, capital constraints could limit our ability to build gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity or sell natural gas production at significantly lower prices than those we currently project, which could materially and adversely affect our results of operations.

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 due 2020 and our 6.25% Senior Notes due 2023 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 the recent decline in oil prices.

In addition, the provisions of our revolving credit facility and our 7.50% Senior Notes and 6.25% 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 and 6.25% 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 and restricts us from making borrowings and requires prepayments if our cash balances exceed certain levels. 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 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 oi and natural gas prices used by the banks in calculating the borrowing base remain significantly lower than those used in the last redetermination, including as a result of the 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 2017. 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 Utica Shale and 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 Utica and the Delaware Basin. We have participated in the drilling of only 18 gross (4.6 net) wells and 13 gross (8.2 net) wells in the Utica and the Delaware Basin, respectively. 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 Utica and the Delaware Basin than we have in some other areas 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 April 2011, the Pennsylvania Department of Environmental Protection (“PADEP”) called on all Marcellus natural gas drilling operators to voluntarily cease by May 19, 2011 delivering wastewater to those centralized treatment facilities that were grandfathered from the application of PADEP’s Total Dissolved Solids regulations. Additionally, 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 natural gas liquids.

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 natural gas liquids 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. For example, in January 2016, the Pennsylvania Department of Environmental Protection announced a final-form rulemaking amending Pennsylvania Code Chapter 78 which sets new performance standards for surface activities at conventional and unconventional oil and gas well sites and announced plans to regulate methane emissions from the drilling industry by revising its permitting process for new gas wells and pipelines and proposing new requirements regulating methane from existing sources. These regulations and other future regulations could add costs and cause delays in our operations. In addition, 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 2011-2016 National Enforcement Initiative, “Assuring 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 June 2016, the U.S. District Court of Wyoming struck down the rule, finding that BLM lacked authority to promulgate the rule. That decision is currently being appealed by the federal government. 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, including Pennsylvania. 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. The draft report is expected to be finalized after a public comment period and a formal review by the EPA's Science Advisory Board. 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 the 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 Colorado, Ohio, and 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 2015, the United States Geological Study identified eight states including Colorado, Ohio, and Texas with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. 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 Colorado, Ohio, Pennsylvania, Texas and West Virginia, 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. For example, in October 2016, the PADEP announced final rules requiring notification for new unconventional wells located near public resources and additional post-drilling well-site and water restoration at hydraulic fracturing sites. These rules are currently the subject of a legal challenge before the Pennsylvania Supreme Court. 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, and New York issued a statewide ban on hydraulic fracturing in June 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 states of Colorado, New York, Ohio, Pennsylvania, Texas and West Virginia, 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 joint ventures, which subject 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 joint ventures with third parties, including GAIL, Haimo, the OIL JV Partners and Reliance. 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

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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 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. 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 impairments of proved oil and gas properties for the years ended December 31, 2016 and 2015 of $576.5 million and $1,224.4 million, respectively. We estimate that the first quarter of 2017 cost center ceiling will exceed the net book value of oil and gas properties, less related deferred income taxes, resulting in no impairment of proved oil and gas properties. This estimate of the first quarter of 2017 cost center ceiling is based on the estimated 12-Month Average Realized Price of crude oil of $44.39 per barrel as of March 31, 2017, which is based on the average realized price for sales of crude oil on the first calendar day of each month for the first 11 months and an estimate for the twelfth month based on a quoted forward price. 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 and remain at low levels.

We could lose our ability to use net operating loss carryforwards that we have accumulated over the years.

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 upon the occurrence of certain ownership changes, including the purchase or sale of our stock by 5% shareholders and our offering of stock during any three-year period resulting in an aggregate change of more than 50% in our beneficial ownership. In the event of 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 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, 2016. Subsequent equity transactions involving us or our 5% shareholders (including, potentially, relatively small transactions and transactions beyond our control) could cause ownership changes and therefore a limitation on the annual utilization of our U.S. loss carryforwards.

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 occurred in 2016 and 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 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 would repeal the expensing of intangible drilling costs, repeal the percentage depletion allowance and increase the amortization period of geological and geophysical expenses. In addition, legislative changes to impose additional taxes have been proposed in Pennsylvania. 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 and our indentures governing our senior notes 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, in either event upon a change in control, as determined under the relevant documents relating to such indebtedness. 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 “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 is expected to petition the Texas Supreme Court to accept the case for review. 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

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
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
2015		
First Quarter	$53.65	$38.44
Second Quarter	56.77	48.51
Third Quarter	49.28	27.79
Fourth Quarter	43.97	28.16

The closing market price of our common stock on February 24, 2017 was $31.73 per share. As of February 24, 2017, there were an estimated 96 owners of record of our common stock.

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 and our senior notes 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."

We have no restricted shares outstanding as of December 31, 2016, aside from Rule 144 restrictions on shares held by insiders and shares issued to non-employee directors under our incentive plan.

For the year ended December 31, 2016, there were no purchases by the Company or affiliated purchasers of shares of the Company's common stock.

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, 2011 to December 31, 2016, 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, 2011, 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, 2011	$100	$100	$100
December 31, 2012	$79	$116	$105
December 31, 2013	$170	$154	$138
December 31, 2014	$158	$175	$123
December 31, 2015	$112	$177	$94
December 31, 2016	$142	$198	$117

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, 2016, 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,				
	2016	2015	2014	2013	2012
	(In thousands, except per share data)				
Statements of Operations:					
Total revenues	$443,594	$429,203	$710,187	$520,182	$368,180
Costs and expenses					
Oil and gas operating	123,322	116,990	112,151	75,340	54,826
Depreciation, depletion and amortization	213,962	300,035	317,383	214,291	165,993
General and administrative	74,972	67,224	77,029	77,492	48,708
(Gain) loss on derivatives, net	49,073	(99,261)	(201,907)	18,417	(31,371)
Interest expense, net	79,403	69,195	53,171	54,689	48,158
Impairment of oil and gas properties	576,540	1,224,367	—	—	—
Loss on extinguishment of debt	—	38,137	—	—	—
Loss on sale of oil and gas properties	—	—	—	45,377	—
Other (income) expense, net	1,796	11,276	2,150	(185)	(267)
Total costs and expenses	1,119,068	1,727,963	359,977	485,421	286,047
Income (Loss) From Continuing Operations Before Income Taxes	(675,474)	(1,298,760)	350,210	34,761	82,133
Income tax (expense) benefit	—	140,875	(127,927)	(12,903)	(30,956)
Income (Loss) From Continuing Operations	($675,474)	($1,157,885)	$222,283	$21,858	$51,177
Basic income (loss) from continuing operations per common share	($11.27)	($22.50)	$4.90	$0.54	$1.29
Diluted income (loss) from continuing operations per common share	($11.27)	($22.50)	$4.81	$0.53	$1.28
Basic weighted average common shares outstanding	59,932	51,457	45,372	40,781	39,591
Diluted weighted average common shares outstanding	59,932	51,457	46,194	41,355	40,026
Statements of Cash Flows:					
Net cash provided by operating activities from continuing operations	$272,768	$378,735	$502,275	$367,474	$253,071
Net cash used in investing activities from continuing operations	(619,832)	(673,376)	(940,676)	(509,885)	(465,151)
Net cash provided by financing activities from continuing operations	308,340	330,767	300,290	120,326	237,778
Capital expenditures - oil and gas properties	($480,929)	($674,612)	($860,604)	($786,976)	($735,711)
Proceeds from sales of oil and gas properties, net	15,564	8,047	12,576	238,470	341,597
Proceeds from issuances of senior notes	—	650,000	301,500	—	300,000
Tender and redemption of senior notes and other payments of long-term debt	—	(776,681)	—	(69,325)	(55,228)
Sale of common stock, net of offering costs	223,739	470,158	—	189,686	—
Balance Sheets:					
Working capital	($138,971)	($50,636)	($141,278)	($32,138)	($43,432)
Total property and equipment, net	1,545,760	1,716,861	2,629,253	1,794,215	1,487,674
Total assets	1,626,327	2,007,246	2,962,305	2,094,364	1,730,731

Long-term debt	1,325,418	1,236,017	1,332,175	883,851	949,051
Total shareholders' equity	23,458	444,054	1,103,441	841,604	585,016

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

Operational Results. Total production for the year ended December 31, 2016 increased 15% from 2015 to 42,276 Boe/d primarily due to production from our wells in the Eagle Ford and Delaware Basin. Crude oil production for 2016 was a 25,745 Bbls/d, an increase of 12% from 2015, primarily driven by strong performance from our wells in the Eagle Ford, which averaged 22,670 Bbls/d for 2016. For further discussion of production, see "—Results of Operations" below.

See the table below for details of our operated drilling and completion activity:

	Year Ended December 31, 2016				December 31, 2016				
	Drilled		Wells Brought on Production		Drilled But Uncompleted		Producing		Rig Count
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
Eagle Ford	77	73.1	71	67.0	35	33.4	446	381.5	2
Delaware Basin	4	4.0	4	3.9	2	2.0	6	5.6	—
Niobrara	—	—	9	5.2	—	—	130	57.9	—
Marcellus	—	—	—	—	11	4.3	81	26.0	—
Utica and other	—	—	—	—	—	—	4	3.1	—
Total	81	77.1	84	76.1	48	39.7	667	474.1	2

Approximately 82% of our 2016 drilling and completion capital expenditures were in the Eagle Ford where, as of December 31, 2016, we were operating two rigs. At December 31, 2016, our estimated net proved oil and gas reserves were 200.2 MMBoe, an increase of 29.5 MMBoe, or 17%, from December 31, 2015. Driven by our drilling program as well as the associated offset locations, we added 58.6 MMBoe to our total proved reserves, primarily in Eagle Ford. See "Item 1. Business—Additional Oil and Gas Disclosures—Proved Oil and Gas Reserves" for additional discussion. Our current 2017 capital expenditure plan includes $530.0 million to $550.0 million for drilling and completion and $20 million for leasehold and seismic. This plan incorporates an assumed increase in oilfield service costs during the year and should allow the Company to run three rigs in the Eagle Ford during the year as well as continue to develop its acreage in the Delaware Basin. Approximately 97% of our 2017 drilling and completion capital expenditure plan is allocated to our continued exploration and development of the Eagle Ford and Delaware Basin. See "—Liquidity and Capital Resources—2017 Capital Expenditure Plan and Funding Strategy" for additional details.

Acquisition Activity. On December 14, 2016, we completed the acquisition of producing wells and acreage primarily in LaSalle, Frio and McMullen counties from Sanchez Energy Corporation and SN Cotulla Assets, LLC, a subsidiary of Sanchez Energy Corporation ("Sanchez Acquisition"). We paid $10.0 million as a deposit on October 24, 2016 and $143.5 million at the initial closing on December 14, 2016, which included purchase price adjustments and adjustments for leases not conveyed to us at the initial close. See "Note 3. Acquisitions" of the Notes to our Consolidated Financial Statements for further details.

Common Stock Offerings. In October 2016, we completed a public offering of 6.0 million shares of our common stock for net proceeds of $223.7 million. The net proceeds from the common stock offering were used to fund the Sanchez Acquisition and to repay borrowings under the revolving credit facility. See "Note 9. Shareholders' Equity and Stock Based Compensation Plans" of the Notes to our Consolidated Financial Statements for further details.

Senior Secured Revolving Credit Facility. In May 2016, in connection with the Spring 2016 borrowing base redetermination, we entered into an amendment to the credit agreement which reduced the borrowing base from

$685.0 million to $600.0 million as well as replaced certain covenants, giving us increased flexibility. In October 2016, as a result of the Fall 2016 borrowing base redetermination, the borrowing base was reaffirmed at $600.0 million. See “Note 6. Long-Term Debt” of the Notes to our Consolidated Financial Statements for further details.

Financial Results. We recorded a loss from continuing operations for the years ended December 31, 2016 and 2015 of $675.5 million, or $11.27 per diluted share, and $1,157.9 million, or $22.50 per diluted share, respectively. The loss from continuing operations for the years ended December 31, 2016 and 2015 was driven by impairments of proved oil and gas properties of $576.5 million and $1,224.4 million, respectively, primarily as a result of declines in the 12-Month Average Realized Prices of crude oil.

Additionally, driven by the impairments of proved oil and gas properties, beginning in the third quarter of 2015, we recorded a valuation allowance against our net deferred tax assets reducing them to zero. See “Note 5. Income Taxes” of the Notes to our Consolidated Financial Statements for further details of the valuation allowance and see “—Results of Operations” below for further discussion of the components of income (loss) from continuing operations.

Results of Operations

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.

Depreciation, depletion and amortization ("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
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	$1,224,367
Beginning of period 12-Month Average Realized price ($/Bbl)	$47.24	$92.24
End of period 12-Month Average Realized price ($/Bbl)	$39.60	$47.24
Percent decrease in 12-Month Average Realized Price	(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. The components of our loss on derivatives, net were as follows:

	Year Ended December 31, 2016 (In thousands)
Crude oil derivative positions:	
Loss due to upward shift in forecasted prices during the current year on derivative positions outstanding at the beginning of the year	$9,816
Loss due to new derivative positions executed during the current year [(1)]	19,575

Natural gas derivative positions:	
Loss due to new derivative positions executed during the current year [1]	19,682
Loss on derivatives, net	$49,073

(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.

We recorded a gain on derivatives, net of $99.3 million for 2015. The components of our gain on derivatives, net were as follows:

	Year Ended December 31, 2015 (In thousands)
Crude oil derivative positions:	
Gain due to downward shift in forecasted prices during the current year on derivative positions outstanding at the beginning of the year	$11,462
Gain due to new derivative positions executed during the current year	83,737
Natural gas derivative positions:	
Gain due to downward shift in forecasted prices during the current year on derivative positions outstanding at the beginning of the year	4,062
Gain due to new derivative positions executed during the current year	—
Gain on derivatives, net	$99,261

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.

Year Ended December 31, 2015 Compared to the Year Ended December 31, 2014

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the years ended December 31, 2015 and 2014:

	Years Ended December 31,		2015 Period Compared to 2014 Period	
	2015	2014	Increase(Decrease)	% Increase(Decrease)
Total production volumes -				
Crude oil (MBbls)	8,415	6,906	1,509	22 %
NGLs (MBbls)	1,352	926	426	46 %
Natural gas (MMcf)	21,812	24,877	(3,065)	(12 %)
Total barrels of oil equivalent (MBoe)	13,402	11,978	1,424	12 %
Daily production volumes by product -				
Crude oil (Bbls/d)	23,054	18,921	4,133	22 %
NGLs (Bbls/d)	3,705	2,537	1,168	46 %
Natural gas (Mcf/d)	59,758	68,156	(8,398)	(12 %)
Total barrels of oil equivalent (Boe/d)	36,719	32,816	3,903	12 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	26,377	21,131	5,246	25 %
Delaware Basin	104	10	94	940 %
Niobrara	2,957	2,585	372	14 %
Marcellus	5,850	8,354	(2,504)	(30 %)
Utica and other	1,431	736	695	94 %
Total barrels of oil equivalent (Boe/d)	36,719	32,816	3,903	12 %
Average realized prices -				
Crude oil ($ per Bbl)	$44.69	$88.40	($43.71)	(49 %)
NGLs ($ per Bbl)	11.54	27.05	(15.51)	(57 %)
Natural gas ($ per Mcf)	1.72	3.00	(1.28)	(43 %)
Total average realized price ($ per Boe)	$32.03	$59.29	($27.26)	(46 %)
Revenues (In thousands) -				
Crude oil	$376,094	$610,483	($234,389)	(38 %)
NGLs	15,608	25,050	(9,442)	(38 %)
Natural gas	37,501	74,654	(37,153)	(50 %)
Total revenues	$429,203	$710,187	($280,984)	(40 %)

Revenues for 2015 decreased 40% to $429.2 million compared to $710.2 million in 2014 primarily due to the decrease in crude oil and natural gas prices, partially offset by the significant increase in crude oil production. Production volumes in 2015 and 2014 were 36,719 Boe/d and 32,816 Boe/d, respectively. The increase in production from 2014 to 2015 was primarily due to increased production from new wells in the Eagle Ford, partially offset by normal production declines and voluntary curtailments of natural gas production in the Marcellus due to unfavorable natural gas prices.

Lease operating expenses for 2015 increased to $90.1 million ($6.72 per Boe) from $74.2 million ($6.19 per Boe) in 2014. The increase in lease operating expenses is primarily due to increased production from new wells in the Eagle Ford. The increase in lease operating expense per Boe is primarily due 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 decreased to $17.7 million (or 4.1% of revenues) in 2015 from $29.5 million (or 4.2% of revenues) in 2014 as a result of the decrease in crude oil and natural gas revenues, partially offset by increased crude oil production. The decrease in production taxes as a percentage of revenues is primarily due to a benefit in the third quarter of 2015 of lower actual production taxes than previously estimated in the Niobrara.

Ad valorem taxes increased to $9.3 million in 2015 from $8.5 million in 2014. The increase in ad valorem taxes is primarily due to new wells drilled in Eagle Ford in 2014, partially offset by a decrease in our annual estimate of ad valorem taxes.

DD&A expense for 2015 decreased $17.3 million to $300.0 million ($22.39 per Boe) from the DD&A expense for 2014 of $317.4 million ($26.50 per Boe). The decrease in DD&A expense is attributable to the decrease in the DD&A rate per Boe, which is primarily due to the impairment recorded in the third quarter of 2015 and reductions in estimated future development costs that occurred throughout 2015. The components of our DD&A expense were as follows:

	Years Ended December 31,	
	2015	2014
	(In thousands)	
DD&A of proved oil and gas properties	$295,452	$313,799
Depreciation of other property and equipment	1,932	1,722
Amortization of other assets	1,539	1,152
Accretion of asset retirement obligations	1,112	710
DD&A	$300,035	$317,383

We recognized an after-tax impairment of $795.8 million ($1,224.4 million pre-tax) in 2015 due primarily to declines in the average realized prices for sales of oil and gas on the first calendar day of each month during the trailing 12-month period prior to December 31, 2015. There were no impairments of proved oil and gas properties in 2014.

General and administrative expense decreased to $67.2 million for 2015 from $77.0 million for 2014. The decrease was primarily due to a decrease in stock-based compensation costs resulting from a decrease in the fair value of stock appreciation rights and a decrease in the number of stock appreciation rights and restricted stock outstanding.

We recorded a gain on derivatives, net of $99.3 million for 2015. The components of our gain on derivatives, net were as follows:

	Year Ended December 31, 2015 (In thousands)
Crude oil derivative positions:	
Gain due to downward shift in forecasted prices during the current year on derivative positions outstanding at the beginning of the year	$11,462
Gain due to new derivative positions executed during the current year	83,737
Natural gas derivative positions:	
Gain due to downward shift in forecasted prices during the current year on derivative positions outstanding at the beginning of the year	4,062
Gain due to new derivative positions executed during the current year	—
Gain on derivatives, net	$99,261

We recorded a gain on derivatives, net of $201.9 million for 2014. The components of our gain on derivatives, net were as follows:

	Year Ended December 31, 2014 (In thousands)
Crude oil derivative positions:	

Gain due to downward shift in forecasted prices during the current year on derivative positions outstanding at the beginning of the year	$78,677
Gain due to new derivative positions executed during the current year	112,674
Natural gas derivative positions:	
Gain due to downward shift in forecasted prices during the current year on derivative positions outstanding at the beginning of the year	1,559
Gain due to new derivative positions executed during the current year	8,997
Gain on derivatives, net	$201,907

Interest expense, net for 2015 was $69.2 million as compared to $53.2 million for 2014. The increase was primarily due to the interest expense on the $300.0 million aggregate principal amount of our 7.50% Senior Notes that were issued in October 2014, the interest expense on the $650.0 million aggregate principal amount of our 6.25% Senior Notes that were issued in April 2015 and a decrease in the associated capitalized interest due to a lower average balance of unproved properties and a lower effective interest rate on debt outstanding during 2015 as compared to 2014, partially offset by a reduction in interest expense associated with the $600.0 million aggregate principal amount of our 8.625% Senior Notes that were redeemed and repurchased in April 2015. The components of our interest expense, net were as follows:

	Years Ended December 31,	
	2015	2014
	(In thousands)	
Interest expense on Senior Notes	$90,882	$78,256
Interest expense on revolving credit facility	4,226	3,265
Amortization of debt issuance costs, premiums, and discounts	4,724	4,703
Other interest expense	1,453	1,492
Capitalized interest	(32,090)	(34,545)
Interest expense, net	$69,195	$53,171

The effective income tax rate was 10.8% for 2015 and 36.5% for 2014. The variance from the U.S. Federal statutory rate of 35% for 2015 was primarily due to a valuation allowance of $323.6 million that was recorded against our net deferred tax asset during 2015. The variance from the U.S. Federal statutory rate of 35% for 2014 was due to the impact of state income taxes.

Income from discontinued operations, net of income taxes for 2015 amounted to $2.7 million. The income from discontinued operations, net of income taxes is related to the sale of Carrizo UK. The income was primarily due to decreases in estimated future obligations as a result of the continued downward shift in the futures curve of forecasted commodity prices for Brent crude oil during 2015.

Liquidity and Capital Resources

2017 Capital Expenditure Plan and Funding Strategy. Our 2017 capital expenditure plan includes $530.0 million to $550.0 million for drilling and completion and $20.0 million for leasehold and seismic. We currently intend to finance our 2017 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 the availability and cost of drilling rigs, 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. Our 2016 capital expenditures of $432.3 million were 21% lower than our 2015 capital expenditures of $544.2 million. The following is a summary of our 2016 capital expenditures:

	Capital Expenditures				
	Three Months Ended				Year Ended
	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016	December 31, 2016
	(In thousands)				
Drilling and completion					
Eagle Ford	$72,417	$82,451	$100,820	$78,856	$334,544
Delaware Basin	8,915	15,308	11,664	11,258	47,145
All other regions	3,516	5,506	13,281	1,874	24,177
Total drilling and completion	84,848	103,265	125,765	91,988	405,866
Leasehold and seismic (2)	5,911	6,427	6,190	7,864	26,392
Total (1)	$90,759	$109,692	$131,955	$99,852	$432,258

(1) Our capital expenditure plan and the capital expenditures included above exclude capitalized general and administrative expense, capitalized interest and capitalized asset retirement obligations.

(2)

Leasehold and seismic capital expenditures exclude amounts related to the Sanchez Acquisition described above under "—General Overview."

Sources and Uses of Cash. Our primary use of cash is related to our drilling and completion capital expenditure plan and, to a lesser extent, our leasehold and seismic capital expenditure plan. During 2016, we funded our capital expenditures with cash provided by operations, borrowings under our revolving credit facility and a portion of the net proceeds from our October 2016 equity offering. 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 our revolving credit facility. As of February 24, 2017, our revolving credit facility had a borrowing base of $600.0 million, with $91.0 million of borrowings outstanding and $0.4 million in letters of credit issued, which reduce the amounts available under our revolving credit facility. 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. In October 2016, we sold 6.0 million shares of our common stock in a public offering at a price of $37.32 per share. We used the proceeds of $223.7 million, net of offering costs, to fund the Sanchez Acquisition and to repay borrowings under the revolving credit facility.
- Asset sales. In order to fund our capital expenditure plan, we may consider the sale of 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 sell such assets on terms that are acceptable to us. We continue to explore sales of non-core properties. We may also consider the sale of properties in areas we have viewed as core, such as the Delaware Basin, particularly if we believe that sales prices for such assets would allow us to deploy capital more effectively in other basins or other parts of the same basin. There can be no assurance, however, that any sales will occur on terms we find to be acceptable, or at all.
- 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 $272.8 million, $378.7 million and $502.3 million for the years ended December 31, 2016, 2015 and 2014, respectively. 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. The decrease from 2014 to 2015 was primarily due to a decrease in oil and gas revenues and an increase in operating expenses and working capital requirements, partially offset by an increase in the net cash from derivative settlements.

Net cash used in investing activities from continuing operations was $619.8 million, $673.4 million and $940.7 million for the years ended December 31, 2016, 2015 and 2014, respectively. 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. The decrease from 2014 to 2015 was primarily due to a reduction in our capital expenditures in 2015 as compared to 2014, as well as a decrease related to the Eagle Ford Acquisition in 2014.

Net cash provided by financing activities from continuing operations for the years ended December 31, 2016, 2015 and 2014 was $308.3 million, $330.8 million and $300.3 million, respectively. 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. The increase from 2014 to 2015 was due to the proceeds related to 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 and the payment of the deferred purchase payment in February 2015.

Liquidity/Cash Flow Outlook. 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, commodity prices and settlements of our commodity derivatives. We currently believe that cash flows from operations and borrowings under our revolving credit facility provide adequate financial flexibility and will be sufficient to fund our immediate cash flow requirements.

- Revolving credit facility. As of February 24, 2017, our revolving credit facility had a borrowing base of $600.0 million, with $91.0 million of borrowings outstanding and $0.4 million in letters of credit issued, which reduce the amounts available under our 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.

As a result of our Fall 2016 borrowing base redetermination, our borrowing base was reaffirmed at $600.0 million. The amount we are able to borrow is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility.

- Hedging. To manage our exposure to commodity price risk and to provide a level of certainty in the cash flows to support our drilling and completion capital expenditure plan, we hedge a portion of our forecasted production.

As of February 24, 2017, we had the following crude oil derivative positions:

Period	Type of Contract	Crude Oil Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
Q1 2017	Fixed Price Swaps	12,000	$50.13	
Q2 2017	Fixed Price Swaps	12,000	$50.13	
Q3 2017	Fixed Price Swaps	6,000	$54.15	
Q4 2017	Fixed Price Swaps	3,000	$55.01	
FY 2018	Sold Call Options	2,488		$60.00
FY 2018	Net Sold Call Options	900		$75.00
FY 2019	Sold Call Options	2,975		$62.50
FY 2019	Net Sold Call Options	900		$77.50
FY 2020	Sold Call Options	3,675		$65.00
FY 2020	Net Sold Call Options	900		$80.00

As of February 24, 2017, we had the following natural gas derivative positions:

Period	Type of Contract	Natural Gas Volumes (in MMBtu/d)	Weighted Average Floor Price ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)
FY 2017	Fixed Price Swaps	20,000	$3.30	
FY 2017	Sold Call Options	33,000		$3.00
FY 2018	Sold Call Options	33,000		$3.25
FY 2019	Sold Call Options	33,000		$3.25
FY 2020	Sold Call Options	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 the remainder of our 2017 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 2017 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 asset sales, securities offerings or borrowings to reduce debt prior to scheduled maturities through debt repurchases, either in the open market or in privately negotiated transactions, through debt 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, 2016 (in thousands):

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
Long-term debt (1)	$—	$87,000	$—	$600,000	$—	$654,425	$1,341,425
Cash interest on senior notes and other long-term debt (2)	85,819	85,819	85,819	85,819	40,819	62,180	446,275
Cash interest and commitment fees on revolving credit facility (3)	4,939	2,494	—	—	—	—	7,433
Capital leases	1,856	1,823	1,800	1,050	—	—	6,529
Operating leases	4,438	4,430	4,412	4,463	4,450	1,854	24,047
Drilling rig contracts (4)	23,753	3,957	—	—	—	—	27,710

Delivery commitments [5]	8,134	8,611	7,298	4,826	3,680	291	32,840
Asset retirement obligations and other [6]	2,218	1,098	322	104	270	19,960	23,972
Total Contractual Obligations	$131,157	$195,232	$99,651	$696,262	$49,219	$738,710	$1,910,231

(1) Long-term debt consists of the principal amounts of the 7.50% Senior Notes due 2020, the 6.25% Senior Notes due 2023, other long-term debt due 2028, and borrowings outstanding under our revolving credit facility which matures in 2018.

(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, 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, 2016 of 2.72%. Commitment fees on our revolving credit facility were calculated based on the unused portion of lender commitments as of December 31, 2016, at the commitment fee rate of 0.500%.

(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 throughput commitments. We may incur volume deficiency fees from time to time if we elect to voluntarily curtail production due to market or operational considerations.

(6) Asset retirement obligations and other are based on estimates and assumptions that affect the reported amounts as of December 31, 2016. Certain of such estimates and assumptions are inherently unpredictable and will differ from actuals results. See “Note 2. Summary of Significant Accounting Policies” for further discussion of estimates and assumptions that may affect the reported amounts.

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, 2016, had a borrowing base of $600.0 million, with $87.0 million of borrowings outstanding at a weighted average interest rate of 2.72% and $0.4 million in letters of credit outstanding. The credit agreement governing our senior secured revolving credit facility provides for interest-only payments until July 2, 2018, when the credit agreement matures and any outstanding borrowings are due. 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, in each case which may reduce the amount of the borrowing base.

See “Note 6. Long-Term Debt” for additional details of the senior secured revolving credit facility including 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.

7.50% Senior Notes and 6.25% Senior Notes

As of December 31, 2016, we had $600.0 million aggregate principal amount of 7.50% Senior Notes due 2020 that were issued and outstanding. Since September 15, 2016 we had the right to redeem all or a portion of the 7.50% Senior Notes at redemption prices decreasing from 103.75% to 100% of the principal amount on September 15, 2018, plus accrued and unpaid interest. In connection with any redemption or repurchase of notes, we could enter into other transactions, which include refinancing of the 7.50% Senior Notes. As of December 31, 2016, we had $650.0 million aggregate principal amount of 6.25% Senior Notes due 2023 that were issued and outstanding. As of December 31, 2016, the 7.50% Senior Notes and the 6.25% Senior Notes are guaranteed by the same subsidiaries that guarantee also guarantee the revolving credit facility.

See “Note 6. Long-Term Debt” for additional details of our 7.50% Senior Notes due 2020 and our 6.25% Senior Notes due 2023.

8.625% Senior Notes

On April 14, 2015, we settled a cash tender offer for any or all of the outstanding $600.0 million aggregate principal amount of our 8.625% Senior Notes at a price of 104.613% of the principal amount plus accrued and unpaid interest. In connection with the cash tender offer, we also sent a notice of redemption to the trustee for our 8.625% Senior Notes to conditionally call for redemption on May 14, 2015 all of the 8.625% Senior Notes then outstanding at a price of 104.313% of the principal amount plus accrued and unpaid interest, conditioned upon and subject to our receipt of specified net proceeds from one or more securities offerings, which conditions were satisfied. On April 28, 2015, we made an aggregate cash payment of $276.4 million for the $264.2 million aggregate principal amount of 8.625% Senior Notes validly tendered in the tender offer, which excluded accrued interest paid of $0.8 million. We paid

$352.6 million to redeem the 8.625% Senior Notes that remained outstanding, which represented $335.8 million of outstanding aggregate principal amount of 8.625% Senior Notes, the redemption premium of $14.5 million, and accrued and unpaid interest of $2.3 million from the last interest payment date up to, but not including, the redemption date. The total price to repurchase and redeem all of the outstanding $600.0 million aggregate principal amount of our 8.625% Senior Notes was $629.8 million. As a result of the cash tender offer and the redemption of our 8.625% Senior Notes, we recorded a loss on extinguishment of debt of approximately $38.1 million during the second quarter of 2015.

Common Stock Offerings

In October 2016, we sold 6.0 million shares of our common stock in a public offering at a price of $37.32 per share, for proceeds of $223.7 million, net of offering costs. We used the net proceeds from the common stock offering to fund the purchase price of the Sanchez Acquisition and to repay borrowings under the revolving credit facility.

In October 2015, we sold 6.3 million shares of our common stock in a public offering at a price of $37.80 per share, for proceeds of $238.8 million, net of offering costs. We used the net proceeds from the common stock offering to repay borrowings under our revolving credit facility and for general corporate purposes.

In March 2015, we sold 5.2 million shares of our common stock in a public offering at a price of $44.75 per share, for proceeds of $231.3 million, net of offering costs. We used the net proceeds from the common stock offering to repay borrowings under our revolving credit facility and for general corporate purposes.

Effects of Inflation and Changes in Prices

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 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 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, 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 $10.5 million, $15.8 million and $18.8 million for the years ended December 31, 2016, 2015 and 2014, 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 capitalized 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 $13.50, $22.05 and $26.20 for the years ended December 31, 2016, 2015 and 2014, respectively.

Unproved properties, not being amortized, include unevaluated leasehold and seismic costs associated with specific unevaluated properties, the cost of exploratory wells in progress, and related capitalized interest. Exploratory wells in progress and 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 and completion 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. We capitalized interest costs associated with our unproved properties totaling $17.0 million, $32.1 million and $34.5 million for the years ended December 31, 2016, 2015 and 2014, respectively. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unproved properties using 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, 2016, 2015 and 2014, 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 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.

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

	Years Ended December 31,	
	2016	2015
Impairment of proved oil and gas properties (in thousands)	$576,540	$1,224,367
Beginning of period 12-Month Average Realized price ($/Bbl)	$47.24	$92.24
End of period 12-Month Average Realized price ($/Bbl)	$39.60	$47.24

Percent decrease in 12-Month Average Realized Price	(16%)	(49%)

The decrease in the 12-Month Average Realized price of crude oil was responsible for a negative revision to our proved reserves for 2016 totaling 6.7 MMBoe (7% of December 31, 2016 proved reserves), consisting primarily of 3.5 MMBoe which was attributable to proved developed reserves of producing wells and proved undeveloped reserves with shorter economic lives and 2.4 MMBoe of proved undeveloped reserves that were no longer economic and removed from proved reserves.

The table below presents various pricing scenarios to demonstrate the sensitivity of our December 31, 2016 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, 2016 and, accordingly, does not consider drilling and completion activity, production, changes in crude oil and natural gas prices and changes in development and operating costs occurring subsequent to December 31, 2016 that may require revisions to estimates of proved reserves. See also Part I, "Item 1A. Risk Factors—If 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, 2016 Actual	$39.60	$1.89	$13	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$43.88	$2.13	$369	$356
Crude Oil and Natural Gas -10%	$35.34	$1.66	($343)	($356)
Crude Oil Price Sensitivity				
Crude Oil +10%	$43.88	$1.89	$331	$318
Crude Oil -10%	$35.34	$1.89	($305)	($318)
Natural Gas Price Sensitivity				
Natural Gas +10%	$39.60	$2.13	$51	$38
Natural Gas -10%	$39.60	$1.66	($25)	($38)

We estimate that the first quarter of 2017 cost center ceiling will exceed the net book value of oil and gas properties, less related deferred income taxes, resulting in no impairment of proved oil and gas properties. This estimate of the first quarter of 2017 cost center ceiling is based on the estimated 12-Month Average Realized Price of crude oil of $44.39 per barrel as of March 31, 2017, which is based on the average realized price for sales of crude oil on the first calendar day of each month for the first 11 months and an estimate for the twelfth month based on a quoted forward price. 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.

Oil and Gas Reserve Estimates

The proved oil and gas reserve estimates as of December 31, 2016 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 and natural gas production and thereby achieve a more predictable level of cash flows to support our drilling and completion capital expenditure program. All derivative instruments are recorded on the consolidated balance sheets as either an asset or liability measured at fair value. We net our 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 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 derivative instruments, including volumes, types of instruments and counterparties. These policies require that 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.

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. 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 benefit of 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, 2016, 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 $648.7 million as of December 31, 2016. Beginning in the third quarter of 2015, we concluded in each subsequent quarterly evaluation that it was more likely than not the deferred tax assets will not be realized and based on evaluation of evidence available as of December 31, 2016, our previous conclusion remains unchanged. As a result, the net deferred tax assets at the end of each quarter, including December 31, 2016 were reduced to zero. The valuation allowance at December 31, 2015 of $324.7 million was increased during the year ended December 31, 2016 by $240.8 million, less a $1.1 million reclassification to a stock based compensation deferred tax asset, bringing the valuation allowance against the net deferred tax assets to $564.4 million at December 31, 2016.

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. As long as we continue to conclude that the valuation allowance against its net deferred tax assets is necessary, we may have additional valuation allowance increases with no significant deferred income tax expense or benefit.

We classify interest and penalties associated with income taxes as interest expense. We follow 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.

Recent Accounting Pronouncements

See “Note 2. Summary of Significant Accounting Policies - Recent Accounting Pronouncements” 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 and natural gas, which are affected by changes in market supply and demand, overall economic activity, global political environment, weather, inventory storage levels, basis differentials 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 crude oil and natural gas production and thereby achieve a more predictable level of cash flows to support our drilling and completion capital expenditure program. We do not enter into derivative instruments for speculative or trading purposes. As of December 31, 2016, our commodity derivative instruments consisted of fixed price swaps, costless collars, and purchased and sold call options. See "Note 11. Derivative Instruments" for further details of our crude oil and natural gas derivative positions as of December 31, 2016.

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 $37.8 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 $4.3 million impact on our revenues for the year ended December 31, 2016.

We use commodity derivative instruments to reduce our exposure to commodity price volatility for a portion of our forecasted crude oil and natural gas production and thereby achieve a more predictable level of cash flows to support our drilling and completion capital expenditure program. We do not enter into derivative instruments for speculative or trading purposes. As of December 31, 2016, our commodity derivative instruments consisted of fixed price swaps, costless collars, and purchased and sold call options. For the years ended December 31, 2016, 2015 and 2014, we recorded in the consolidated statements of operations a loss on derivatives, net of $49.1 million and a gain on derivatives, net of $99.3 million and $201.9 million, respectively. We also received net cash on derivative settlements of $119.4 million and $194.3 million for the years ended December 31, 2016 and 2015, respectively, and paid net cash on derivative settlements of $13.5 million for the year ended December 31, 2014, which are presented in the consolidated statements of cash flows.

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, and other long-term debt as of December 31, 2016 were estimated at approximately $624.8 million, $672.8 million, and $4.4 million, respectively, and were based on quoted market prices. As of December 31, 2016, scheduled maturities of debt are
$600.0 million in 2020, $650.0 million in 2023, and $4.4 million in 2028. We had $87.0 million of borrowings outstanding under our revolving credit facility as of December 31, 2016.

Item 8. Financial Statements and Supplementary Data

The financial statements and information required by this Item appears on pages F-1 through F-40 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 KPMG, 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, 2016. 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, 2016.

KPMG 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, 2016, 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, 2016 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 "2017 Proxy Statement") for our 2017 annual meeting of shareholders. The 2017 Proxy Statement will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

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 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

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

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2017 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2016.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a)(1) Financial Statements

The response to this item is submitted in a separate section of this Annual Report on Form 10-K.

(a)(2) Financial Statement Schedules

None.

(a)(3) Exhibits

EXHIBIT INDEX

Exhibit Number	Description
†3.1	Amended and Restated Articles of Incorporation of the Company (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 (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	Amended and Restated Bylaws of the Company (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 among Carrizo Oil & Gas, Inc., the subsidiaries named therein and Wells Fargo Bank, National Association, as trustee, dated May 28, 2008 (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)).

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†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	Officers' Certificate of the Company 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)).
†4.22	Officers' Certificate of the Company 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)).
†4.23	Form of Warrant issued pursuant to Land Agreement dated November 24, 2009 (incorporated herein by reference to Exhibit 4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 000-29187-87)).
*†10.1	Amended and Restated Incentive Plan of the Company effective as of May 15, 2014 (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	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)).
*†10.3	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)).
*†10.4	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)).
*†10.5	Retirement and Consulting Agreement effective as of August 11, 2014 by and between Carrizo Oil & Gas, Inc. and Paul F. Boling (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 000-29187-87)).
*†10.6	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)).
*†10.7	Retirement and Consulting Agreement effective as of December 15, 2014 by and between Carrizo Oil & Gas, Inc. and Gregory E. Evans (incorporated herein by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 100-29187-87)).
*†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 (Filed No. 100-29187-87)).

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*†10.12 —	Form of Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.43 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 000-29187-87)).
*†10.13 —	Form of Director Restricted Stock Unit Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 17, 2013 (File No. 000-29187-87)).
*†10.14 —	Form of 2010 Employee Restricted Stock Unit Award Agreement (with performance-based vesting and time-based vesting) (incorporated herein by reference to Exhibit 10.12 to the Company's Annual Report on Form 10-K for the year ended December 31, 2010 (File No. 000-29187-87)).
*†10.15 —	Form of Employee Restricted Stock Award Agreement (Officer) under the Incentive Plan of Carrizo Oil & Gas, Inc. (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)).
*†10.16 —	Form of Employee Restricted Stock Unit Award Agreement (Officer) under the Incentive Plan of Carrizo Oil & Gas, Inc. (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)).
*†10.17 —	Form of 2009 Employee Cash or Stock Settled Stock Appreciation Rights Award Agreement under the Carrizo Oil & Gas, Inc. Incentive Plan (incorporated herein by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K filed on June 9, 2009 (File No. 000-29187-87)).
*†10.18 —	Form of Employee Stock Appreciation Rights Agreement (Officer) under Incentive Plan of Carrizo Oil & Gas, Inc. (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)).
*†10.19 —	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)).
*†10.20 —	Form of 2009 Employee Cash-Settled Stock Appreciation Rights Award Agreement pursuant to the Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan (incorporated herein by reference to Exhibit 10.11 to the Company's Current Report on Form 8-K filed on June 9, 2009 (File No. 000-29187-87)).
*†10.21 —	Form of Employee Stock Appreciation Rights Agreement (Officer) pursuant to 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)).
*†10.22 —	Form of Employee Performance Share Award Agreement under Incentive Plan of Carrizo Oil & Gas, Inc. (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)).
†10.23 —	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)).

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†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 October 31, 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	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)).
†10.33	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)).
†10.34	Omnibus Amendment among Carrizo (Marcellus) LLC, Carrizo Oil & Gas, Inc., Avista Capital Partners II, L.P. and ACP II Marcellus LLC, dated as of September 10, 2010 (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on September 16, 2010 (File No. 000-29187-87)).
†10.35	Amended and Restated Participation Agreement, dated as of November 16, 2010, and effective as of October 1, 2010, among Carrizo (Marcellus) WV LLC, Carrizo Oil & Gas, Inc., Avista Capital Partners II, L.P. and ACP II Marcellus LLC (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 19, 2010 (File No. 000-29187-87)).
21.1	Subsidiaries of the Company.
23.1	Consent of KPMG LLP.
23.2	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, 2016.
101	Interactive Data Files.

† Incorporated by reference as indicated.

* Management contract or compensatory plan or arrangement.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Carrizo Oil & Gas, Inc. and subsidiaries (the Company) as of December 31, 2016 and 2015, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three 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 2015, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

As discussed in note 2 to the financial statements, the Company changed its method of accounting for deferred income taxes effective January 1, 2016 due to the adoption of FASB ASU 2015-17, Balance Sheet Classification of Deferred Taxes.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2017 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 27, 2017

Report of Independent Registered Public Accounting Firm
The Board of Directors and Shareholders
Carrizo Oil & Gas, Inc.:

We have audited Carrizo Oil & Gas, Inc.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Carrizo Oil & Gas, Inc.'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 Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Carrizo Oil & Gas, Inc.'s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Carrizo Oil & Gas, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Carrizo Oil & Gas, Inc. and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2016, and our report dated February 27, 2017 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 27, 2017

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

	December 31, 2016	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents	$4,194	$42,918
Accounts receivable, net	64,208	54,721
Derivative assets	1,237	131,100
Other current assets	3,349	3,443
Total current assets	72,988	232,182
Property and equipment		
Oil and gas properties, full cost method		
Proved properties, net	1,294,667	1,369,151
Unproved properties, not being amortized	240,961	335,452
Other property and equipment, net	10,132	12,258
Total property and equipment, net	1,545,760	1,716,861
Deferred income taxes	—	46,758
Derivative assets	—	1,115
Other assets	7,579	10,330
Total Assets	$1,626,327	$2,007,246
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable	$55,631	$74,065
Revenues and royalties payable	38,107	67,808
Accrued capital expenditures	36,594	39,225
Accrued interest	22,016	21,981
Accrued lease operating expense	12,377	11,588
Liabilities of discontinued operations	—	2,666
Deferred income taxes	—	46,758
Derivative liabilities	22,601	—
Other current liabilities	24,633	21,393
Total current liabilities	211,959	285,484
Long-term debt	1,325,418	1,236,017
Liabilities of discontinued operations	—	1,088
Asset retirement obligations	20,848	16,183
Derivative liabilities	27,528	12,648
Other liabilities	17,116	11,772
Total liabilities	1,602,869	1,563,192
Commitments and contingencies		
Shareholders' equity		
Common stock, $0.01 par value, 90,000,000 shares authorized; 65,132,499 issued and outstanding as of December 31, 2016 and 58,332,993 issued and outstanding as of December 31, 2015	651	583
Additional paid-in capital	1,665,891	1,411,081
Accumulated deficit	(1,643,084)	(967,610)
Total shareholders' equity	23,458	444,054

Total Liabilities and Shareholders' Equity	$1,626,327	$2,007,246

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 data)

	Years Ended December 31,		
	2016	2015	2014
Revenues			
Crude oil	$378,073	$376,094	$610,483
Natural gas liquids	22,428	15,608	25,050
Natural gas	43,093	37,501	74,654
Total revenues	443,594	429,203	710,187
Costs and Expenses			
Lease operating	98,717	90,052	74,157
Production taxes	19,046	17,683	29,544
Ad valorem taxes	5,559	9,255	8,450
Depreciation, depletion and amortization	213,962	300,035	317,383
General and administrative, net	74,972	67,224	77,029
(Gain) loss on derivatives, net	49,073	(99,261)	(201,907)
Interest expense, net	79,403	69,195	53,171
Impairment of proved oil and gas properties	576,540	1,224,367	—
Loss on extinguishment of debt	—	38,137	—
Other expense, net	1,796	11,276	2,150
Total costs and expenses	1,119,068	1,727,963	359,977
Income (Loss) From Continuing Operations Before Income Taxes	(675,474)	(1,298,760)	350,210
Income tax (expense) benefit	—	140,875	(127,927)
Income (Loss) From Continuing Operations	($675,474)	($1,157,885)	$222,283
Income From Discontinued Operations, Net of Income Taxes	—	2,731	4,060
Net Income (Loss)	($675,474)	($1,155,154)	$226,343
Net Income (Loss) Per Common Share - Basic			
Income (loss) from continuing operations	($11.27)	($22.50)	$4.90
Income (loss) from discontinued operations, net of income taxes	—	0.05	0.09
Net income (loss)	($11.27)	($22.45)	$4.99
Net Income (Loss) Per Common Share - Diluted			
Income (loss) from continuing operations	($11.27)	($22.50)	$4.81
Income (loss) from discontinued operations, net of income taxes	—	0.05	0.09
Net income (loss)	($11.27)	($22.45)	$4.90
Weighted Average Common Shares Outstanding			
Basic	59,932	51,457	45,372
Diluted	59,932	51,457	46,194

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 data)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Shareholders' Equity
	Shares	Amount			
Balance as of January 1, 2014	45,468,675	$455	$879,948	($38,799)	$841,604
Stock options exercised for cash	33,086	1	436	—	437
Stock-based compensation	—	—	30,280	—	30,280
Restricted stock award issuances and restricted stock unit vestings, net of forfeitures	625,301	5	(96)	—	(91)
Other	862	—	4,868	—	4,868
Net income	—	—	—	226,343	226,343
Balance as of December 31, 2014	46,127,924	$461	$915,436	$187,544	$1,103,441
Stock options exercised for cash	2,433	—	46	—	46
Stock-based compensation	—	—	25,707	—	25,707
Restricted stock award issuances and restricted stock unit vestings, net of forfeitures	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	—	—	31,194	—	31,194
Restricted stock award issuances and restricted stock unit vestings, net of forfeitures	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

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,		
	2016	2015	2014
Cash Flows From Operating Activities			
Net income (loss)	($675,474)	($1,155,154)	$226,343
Income from discontinued operations, net of income taxes	—	(2,731)	(4,060)
Adjustments to reconcile income (loss) from continuing operations to net cash provided by operating activities from continuing operations			
Depreciation, depletion and amortization	213,962	300,035	317,383
Impairment of proved oil and gas properties	576,540	1,224,367	—
(Gain) loss on derivatives, net	49,073	(99,261)	(201,907)
Cash received (paid) for derivative settlements, net	119,369	194,296	(13,529)
Loss on extinguishment of debt	—	38,137	—
Stock-based compensation expense, net	36,086	14,729	25,878
Deferred income taxes	—	(140,875)	127,927
Non-cash interest expense, net	4,172	4,289	4,272
Other, net	3,753	5,709	2,379
Changes in components of working capital and other assets and liabilities-			
Accounts receivable	(12,836)	29,781	(1,334)
Accounts payable	(30,130)	(12,617)	27,238
Accrued liabilities	(7,938)	(17,517)	(3,096)
Other assets and liabilities, net	(3,809)	(4,453)	(5,219)
Net cash provided by operating activities from continuing operations	272,768	378,735	502,275
Net cash used in operating activities from discontinued operations	—	(1,368)	(656)
Net cash provided by operating activities	272,768	377,367	501,619
Cash Flows From Investing Activities			
Capital expenditures - oil and gas properties	(480,929)	(675,952)	(861,354)
Acquisitions of oil and gas properties	(153,521)	(1,817)	(92,961)
Proceeds from sales of oil and gas properties, net	15,564	8,047	12,576
Other, net	(946)	(3,654)	1,063
Net cash used in investing activities from continuing operations	(619,832)	(673,376)	(940,676)
Net cash used in investing activities from discontinued operations	—	(2,678)	(7,834)
Net cash used in investing activities	(619,832)	(676,054)	(948,510)
Cash Flows From Financing Activities			
Issuance of senior notes	—	650,000	301,500
Tender and redemption of senior notes	—	(626,681)	—
Payment of deferred purchase payment	—	(150,000)	—
Borrowings under credit agreement	770,291	1,126,860	986,041
Repayments of borrowings under credit agreement	(683,291)	(1,126,860)	(986,041)
Payments of debt issuance costs	(1,330)	(12,420)	(6,510)
Sale of common stock, net of offering costs	223,739	470,158	—
Excess tax benefits from stock-based compensation	—	—	4,863
Proceeds from stock options exercised	—	46	437
Other, net	(1,069)	(336)	—
Net cash provided by financing activities from continuing operations	308,340	330,767	300,290
Net cash provided by financing activities from discontinued operations	—	—	—
Net cash provided by financing activities	308,340	330,767	300,290

Net Increase (Decrease) in Cash and Cash Equivalents	(38,724)	32,080	(146,601)
Cash and Cash Equivalents, Beginning of Year	42,918	10,838	157,439
Cash and Cash Equivalents, End of Year	$4,194	$42,918	$10,838

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

CARRIZO OIL & GAS, INC.
NOTES TO 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 oil, NGLs, and gas primarily 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, the Delaware Basin in West Texas, the Niobrara Formation in Colorado, the Utica Shale in Ohio, and the Marcellus Shale in Pennsylvania.

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, 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 $34.3 million and $49.1 million as of December 31, 2016 and 2015, respectively.

Accounts Receivable

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, 2016 and 2015, the Company’s allowance for doubtful accounts was $0.8 million and $1.0 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 56%, 65%, and 44% of the Company's total revenues in 2016, 2015, and 2014, respectively. Flint Hills Resources, LP, an indirect wholly owned subsidiary of Koch Industries, Inc. accounted for approximately 15%, 9% and 26% of the Company's total revenues in 2016, 2015 and 2014, 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 $10.5 million, $15.8 million and $18.8 million for the years ended December 31, 2016, 2015 and 2014, 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 $13.50, $22.05 and $26.20 for the years ended December 31, 2016, 2015 and 2014, respectively.

Unproved properties, not being amortized, include unevaluated leasehold and seismic costs associated with specific unevaluated properties, the cost of exploratory wells in progress, and related capitalized interest. Exploratory wells in progress and 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 and completion 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. The Company capitalized interest costs associated with its unproved properties totaling $17.0 million, $32.1 million and $34.5 million for the years ended December 31, 2016, 2015 and 2014, 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, natural gas liquids 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.

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, respectively, due primarily to declines in the 12-Month Average Realized Price of crude oil. See “Note 4. Property and Equipment, Net” for further details of the impairments.

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, 2016, 2015 and 2014, the Company did not have any sales of oil and gas properties that significantly altered such relationship.

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. See “—Recently Adopted Accounting Pronouncements” below for discussion of classification debt issuance costs in the consolidated balance sheets.

Financial Instruments

The Company’s financial instruments consist of cash and cash equivalents, receivables, payables, derivative assets and liabilities 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 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 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, 2016 and 2015, 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 and natural gas production and thereby achieve a more predictable level of cash flows to support the Company’s drilling and completion capital expenditure program. All derivative instruments are recorded on the consolidated balance sheets as either an asset or liability measured at fair value. The Company nets its 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 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 derivative instruments, including volumes, types of instruments and counterparties. These policies require that 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 derivative instruments.

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.

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 (using the Black-Scholes-Merton option pricing model) with the liability subsequently remeasured at each reporting period and recognized over the vesting period (generally two or three years) using the graded vesting method. Each award includes a performance condition that must be met in order for that award to vest. For periods subsequent to vesting and prior to exercise, stock-based compensation expense is based on the fair value liability remeasured at each reporting period based on the intrinsic value of the SAR. The liability for SARs is classified as “Other current liabilities” for the value of the awards that are vested or are expected to vest within the next 12 months, 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.

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. Each award includes a performance condition that must be met in order for that award to vest. 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. See "Note 9. Shareholders' Equity and Stock Based Compensation Plans."

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.

Income (Loss) From Continuing Operations Per Common Share

Basic income (loss) from continuing operations per common share is based on the weighted average number of shares of common stock outstanding during the year. Diluted income from continuing operations 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 from continuing operations exists, all potentially dilutive common shares outstanding are anti-dilutive and therefore excluded from the calculation of diluted weighted average shares outstanding.

Supplemental income (loss) from continuing operations per common share information is provided below:

	Years Ended December 31,		
	2016	2015	2014
	(In thousands, except per share amounts)		
Income (Loss) From Continuing Operations	($675,474)	($1,157,885)	$222,283
Basic weighted average common shares outstanding	59,932	51,457	45,372
Effect of dilutive instruments:			
Restricted stock awards and units	—	—	684
Performance share awards	—	—	56
Stock options	—	—	13
Warrants	—	—	69
Diluted weighted average common shares outstanding	59,932	51,457	46,194
Income (Loss) From Continuing Operations Per Common Share			
Basic	($11.27)	($22.50)	$4.90
Diluted	($11.27)	($22.50)	$4.81

For the years ended December 31, 2016 and 2015, the Company reported a loss from continuing operations and therefore the calculation of diluted weighted average common shares outstanding excluded the anti-dilutive effect of 0.7 million and 0.6 million potentially dilutive common shares outstanding, respectively. For the year ended December 31, 2014, the number of potentially dilutive common shares outstanding excluded from the calculation of diluted weighted average shares outstanding was not significant.

Recently Adopted Accounting Pronouncements

In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-17, Balance Sheet Classification of Deferred Taxes ("ASU 2015-17"). ASU 2015-17 requires that all deferred tax liabilities and assets, as well as any related valuation allowance, be classified in the balance sheet as noncurrent rather than presenting the deferred tax liabilities and assets as net current or net noncurrent. Effective January 1, 2016, the Company early adopted ASU 2015-17 which was applied prospectively and therefore the adoption had no impact on the consolidated balance sheet as of December 31, 2015.

In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). ASU 2015-03 simplifies the presentation of debt issuance costs in financial statements by presenting such costs in the balance sheet as a direct deduction from the related debt rather than as an asset. In August 2015, the FASB issued ASU 2015-15, Interest-Imputation of Interest (Subtopic 835-30) ("ASU 2015-15"), which allows debt issuance costs associated with line-of-credit agreements to be deferred and presented as an asset in the balance sheet, subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. Effective January 1, 2016, the Company adopted ASU 2015-03 and ASU 2015-15 and reclassified $19.7 million of unamortized debt issuance costs related to the Company's senior notes from long-term assets to long-term debt in the consolidated balance sheet as of December 31, 2015. Debt issuance costs associated with the Company's revolving credit facility remain classified as a long-term asset in the consolidated balance sheets.

Recently Issued Accounting Pronouncements

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows (Topic 230) ("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. ASU 2016-15 is effective for interim and annual periods beginning after December 15, 2017, with early adoption permitted, provided that it is adopted in its entirety in the same period. The Company is evaluating ASU 2016-15 to determine what impact adoption of the new standard will have on its consolidated statements of cash flows.

In March 2016, the FASB issued 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. The Company adopted ASU 2016-09 effective January 1, 2017. The recognition of previously unrecognized windfall tax benefits is expected to result in a cumulative-effect adjustment of approximately $15.7 million, which would increase net deferred tax assets and increase the valuation allowance by the same amount as of the beginning of 2017, resulting in no impact to the consolidated statements of operations. The remaining provisions of this amendment are not expected to have a material effect on the Company's consolidated financial statements and related disclosures.

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. Lessees and lessors are required 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 evaluating ASU 2016-02 to determine what impact adoption of the new standard will have on its consolidated financial statements and related disclosures.

In May 2014, the FASB issued ASU No. 2014-09, Revenue From Contracts With Customers (Topic 606) ("ASU 2014-09"), which will require entities to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 will supersede most current guidance related to revenue recognition when it becomes effective. The new standard also will require expanded disclosures regarding the nature, timing, amount and certainty of revenue and cash flows from contracts with customers. ASU 2014-09 is effective for interim and annual periods beginning after December 15, 2017 with early adoption permitted for interim and annual periods beginning after December 31, 2016. Companies are permitted to adopt ASU 2014-09 through the use of either the full retrospective approach or a modified retrospective approach. The Company is still in the process of assessing its contracts with customers and assessing their potential impact on the Company's consolidated financial statements and related disclosures. The Company currently plans to apply the modified retrospective method upon adoption and plans to adopt the guidance on the effective date of January 1, 2018.

3. Acquisitions

2016 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 in the Eagle Ford Shale primarily in LaSalle, Frio and McMullen, Texas counties (the “Sanchez Acquisition”) for a purchase price of $181.0 million, subject to customary purchase price adjustments. The transaction had an effective date of June 1, 2016. The Company paid $10.0 million as a deposit upon signing the purchase and sale agreement and $143.5 million at the initial closing on December 14, 2016, which included purchase price adjustments primarily related to net cash flows from the acquired wells from the effective date to the closing date of $10.7 million and adjustments of $16.8 million for leases not conveyed to the Company at the initial closing. The Sanchez Acquisition was funded with of portion of the net proceeds from the October 2016 common stock offering described in “Note 9. Shareholders’ Equity and Stock Based Compensation Plans.”

The Sanchez Acquisition was accounted for under the acquisition method of accounting whereby the purchase price was allocated to the assets acquired and liabilities assumed based on their estimated acquisition date fair values based on currently available information. A combination of a discounted cash flow model and market data was used 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 purchase price allocation for the Sanchez Acquisition is preliminary and subject to change based on subsequent closings related to the leases that were not conveyed to the Company at the initial closing on December 14, 2016 and updates to purchase price adjustments. The following presents the purchase price and the preliminary allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date. These amounts will be finalized as soon as possible, but no later than December 14, 2017.

	December 14, 2016 (In thousands)
Assets	
Other current assets	$477
Oil and gas properties	
Proved properties	90,661
Unproved properties	67,263
Total oil and gas properties	157,924
Total assets acquired	$158,401
Liabilities	
Revenues and royalties payable	$1,442
Other current liabilities	323
Asset retirement obligations	2,037
Other liabilities	1,078
Total liabilities assumed	$4,880
Net Assets Acquired	$153,521

Included in the consolidated statement of operations for the year ended December 31, 2016 are revenues of $1.5 million and income from continuing operations before income taxes of $1.0 million from the Sanchez Acquisition, representing activity of the acquired properties subsequent to the closing of the transaction.

2014 EFM Acquisition

On October 24, 2014, the Company completed the acquisition of interests in oil and gas properties (the “Properties”) from Eagle Ford Minerals, LLC (“EFM”) primarily in LaSalle, Atascosa and McMullen counties, Texas in the Eagle Ford (the “Eagle Ford Shale Acquisition”). The Eagle Ford Shale Acquisition had an effective date of October 1, 2014, with an agreed upon purchase price of $250.0 million, of which the Company paid a total of $241.8 million, net of post-closing and working capital adjustments, which consisted of approximately $93.0 million at closing and $148.8 million on February 13, 2015. Prior to the Eagle Ford Shale Acquisition, the Company and EFM were joint working interest owners in the Properties, for which the Company acted as the operator and owned an approximate 75% working interest in all of such Properties. After giving effect to the Eagle Ford Shale Acquisition, the Company holds an approximate 100% working interest in the Properties. The deferred purchase payment was discounted by $2.6 million to an acquisition date fair value of $147.4 million. For the further discussion of the accounting for the deferred purchase payment, see “Note 6. Long-Term Debt.”

The Eagle Ford Shale Acquisition was accounted for under the acquisition method of accounting whereby the purchase price is allocated to the assets acquired and liabilities assumed based on their estimated acquisition date fair values. Purchase price adjustments of $3.2 million relate to the net operating cash flows and capital expenditures associated with the acquired interests in oil and gas properties for the period from the October 1, 2014 effective date to the October 24, 2014 closing date.

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

	October 24, 2014 (In thousands)
Assets	
Other current assets	$485
Proved and unproved oil and gas properties	244,124
Total assets acquired	$244,609
Liabilities	
Asset retirement obligations	$423
Total liabilities assumed	$423
Net Assets Acquired	$244,186

Included in the consolidated statements of operations for the year ended December 31, 2014 are revenues of $13.1 million and income from continuing operations before income taxes of $11.0 million from the Properties, representing activity 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, 2014, and December 31, 2013, assuming the Eagle Ford Shale Acquisition had been completed as of January 1, 2013, including adjustments to reflect the 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 Eagle Ford Shale Acquisition.

	Year Ended December 31, 2014 (In thousands, except per share data) (Unaudited)
Total revenues	$761,199
Income From Continuing Operations	$264,714
Income From Continuing Operations Per Common Share	
Basic	$5.83
Diluted	$5.73

Weighted Average Common Shares Outstanding	
Basic	45,372
Diluted	46,194

4. Property and Equipment, Net

As of December 31, 2016 and 2015, total property and equipment, net consisted of the following:

	December 31,	
	2016	2015
Oil and gas properties, full cost method	(In thousands)	
Proved properties	$4,687,416	$3,976,511
Accumulated DD&A and impairments	(3,392,749)	(2,607,360)
Proved properties, net	1,294,667	1,369,151
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	211,067	280,263
Exploratory wells in progress	—	9,432
Capitalized interest	29,894	45,757
Total unproved properties, not being amortized	240,961	335,452
Other property and equipment	23,127	22,677
Accumulated depreciation	(12,995)	(10,419)
Other property and equipment, net	10,132	12,258
Total property and equipment, net	$1,545,760	$1,716,861

Costs not subject to amortization totaling $241.0 million at December 31, 2016 were incurred in the following periods: $120.5 million in 2016, $20.7 million in 2015 and $99.8 million in 2014.

Impairment of Proved Oil and Gas Properties

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

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

The Company estimates that the March 31, 2017 cost center ceiling will exceed the net book value of oil and gas properties, less related deferred income taxes and accordingly does not expect an impairment of proved oil and gas properties for the three months ended March 31, 2017. The estimated first quarter of 2017 cost center ceiling is based on the estimated 12-Month Average Realized Price of crude oil of $44.39 per barrel as of March 31, 2017, which is calculated using the average realized price for sales of crude oil on the first calendar day of each month for the first 11 months and an estimate for the twelfth month based on a quoted forward price. 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.

5. Income Taxes

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

	Years Ended December 31,		
	2016	2015	2014
	(In thousands)		
Current income tax (expense) benefit			
U.S. Federal	$—	$—	$—
State	—	—	—
Total current income tax (expense) benefit	—	—	—
Deferred income tax (expense) benefit			
U.S. Federal	—	131,502	(122,342)
State	—	9,373	(5,585)
Total deferred income tax (expense) benefit	—	140,875	(127,927)
Total income tax (expense) benefit from continuing operations	$—	$140,875	($127,927)

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,		
	2016	2015	2014
	(In thousands)		
Income (loss) from continuing operations before income taxes	($675,474)	($1,298,760)	$350,210
Income tax (expense) benefit at the statutory rate	236,416	454,566	(122,574)
State income tax (expense) benefit, net of U.S. Federal income taxes	3,894	9,373	(5,585)
Texas Franchise Tax rate reduction, net of U.S. Federal income tax expense	—	1,671	—
Deferred tax asset valuation allowance	(240,864)	(323,586)	—
Other	554	(1,149)	232
Total income tax (expense) benefit from continuing operations	$—	$140,875	($127,927)

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, 2016 and 2015, deferred tax assets and liabilities are comprised of the following:

	December 31,	
	2016	2015
	(In thousands)	
Deferred income tax assets		
Net operating loss carryforward - U.S. Federal and State	$221,063	$119,783
Oil and gas properties	309,848	232,786
Asset retirement obligations	7,434	5,779
Stock-based compensation	5,238	4,741
Derivative liabilities	17,545	4,433
Other	3,739	3,435
Deferred income tax assets	564,867	370,957
Deferred tax asset valuation allowance	(564,434)	(324,681)
Net deferred income tax assets	433	46,276
Deferred income tax liabilities		
Derivative assets	(433)	(46,276)
Net deferred income tax asset (liability)	$—	$—

All deferred income tax assets, net of related valuation allowances, and liabilities for 2016 are classified as noncurrent in the accompanying consolidated balance sheet upon the Company's early adoption of ASU 2015-17 on a prospective basis. Prior year amounts have not been restated. See "Recently Adopted Accounting Pronouncements" in "Note 2. Summary of Significant Accounting Policies" for additional discussion. At December 31, 2016 and 2015, the net deferred income tax asset (liability) is classified as follows:

	December 31,	
	2016	2015
	(In thousands)	
Net current deferred income tax liability	$—	$(46,758)
Net noncurrent deferred income tax asset	—	46,758
Net deferred income tax asset (liability)	$—	$—

Deferred tax asset valuation allowance. 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, 2016, driven primarily by the recording of 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 the Company's potential for future growth. Beginning in the third quarter of 2015, the Company concluded in each subsequent quarterly evaluation that it was more likely than not the deferred tax assets will not be realized and based on evaluation of evidence available as of December 31, 2016, the Company's previous conclusion remains unchanged. As a result, the net deferred tax assets at the end of each quarter, including December 31, 2016 were reduced to zero. The valuation allowance at December 31, 2015 of $324.7 million was increased during the year ended December 31, 2016 by $240.8 million, less a $1.1 million reclassification to a stock based compensation deferred tax asset, bringing the valuation allowance against the net deferred tax assets to $564.4 million at December 31, 2016.

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 taxable income. As long as the Company continues to conclude that the valuation allowance against its net deferred tax assets is necessary, the Company may have additional valuation allowance increases with no significant deferred income tax expense or benefit.

Net Operating Loss Carryforwards and Other

Net Operating Loss Carryforwards. As of December 31, 2016, the Company had U.S. federal net operating loss carryforwards of approximately $648.7 million. If not utilized in earlier periods, the U.S. federal net operating loss will expire between 2026 and 2036.

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 (a) the fair market value of the equity of the Company 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.

As of December 31, 2016, 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.
The Company receives a tax deduction during the period performance share units, restricted stock awards, and restricted stock units vest, generally equal to the fair value of the awards and units on the vesting date. The Company also receives a tax deduction during the period stock options and SARs are exercised, generally for the excess of the exercise date stock price over the exercise price of the option or SAR. Because these stock-based compensation tax deductions did not reduce current taxes payable as a result of U.S. loss carryforwards, the benefit of these tax deductions has not been reflected in the U.S. loss carryforward deferred tax asset. Stock-based compensation tax deductions included in the U.S. loss carryforwards of $648.7 million but not reflected in the associated deferred tax asset were $44.7 million as of December 31, 2016. The Company expects to recognize the $15.7 million deferred tax asset associated with these stock-based compensation tax deductions under the tax law ordering approach which looks to the provision within the tax law for determining the sequence in which the U.S. loss carryforwards and other tax attributes are utilized. When the stock-based compensation tax deduction related U.S. loss carryforward deferred tax asset is realized, the tax benefit of reducing current taxes payable will be credited directly to additional paid-in capital.
Other. The Company files income tax returns in the U.S. Federal jurisdiction, in various states and previously filed in one foreign jurisdiction, each with varying statutes of limitations. The 1999 through 2016 tax years generally remain subject to examination by federal and state tax authorities. The foreign jurisdiction generally remains subject to examination by the relevant taxing authority for the 2015 and 2016 tax years through 2017 and 2018, respectively.
The Company received notice in January 2015 from the Large Business and International Division of the Internal Revenue Service (the "Service") that the Company's 2012 Federal Tax Return was selected for examination. The examination commenced in February 2015, and the Service concluded the examination of the Company's 2012 Federal Tax Return records in November 2015. The exam concluded with no material adjustments made to the Company's 2012 Federal Tax Return and no open items pending further action between the Company and the Service. As of December 31, 2016, 2015 and 2014, the Company had no uncertain tax positions.

6. Long-Term Debt

Long-term debt consisted of the following as of December 31, 2016 and 2015:

	December 31,	
	2016	2015
	(In thousands)	
Senior Secured Revolving Credit Facility	$87,000	$—
7.50% Senior Notes due 2020	600,000	600,000
Unamortized premium for 7.50% Senior Notes	1,020	1,251
Unamortized debt issuance costs for 7.50% Senior Notes	(7,573)	(9,048)
6.25% Senior Notes due 2023	650,000	650,000
Unamortized debt issuance costs for 6.25% Senior Notes	(9,454)	(10,611)
Other long-term debt due 2028	4,425	4,425
Long-term debt	$1,325,418	$1,236,017

Senior Secured Revolving Credit Facility

The Company has a senior secured revolving credit facility with a syndicate of banks that, as of December 31, 2016, had a borrowing base of $600.0 million, with $87.0 million of borrowings outstanding at a weighted average interest rate of 2.72%. As of December 31, 2016, 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 July 2, 2018, 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, in each case which 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.

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 as set forth in the table below on the unused portion of lender commitments, which are included in interest expense, net.

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%	0.500%
Greater than or equal to 25% but less than 50%	1.25%	2.25%	0.500%
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 Secured Debt to EBITDA of not more than 2.00 to 1.00; and (2) a Current Ratio of not less than 1.00 to 1.00; and (3) a ratio of EBITDA to Interest Expense of not less than 2.50 to 1.00. As of December 31, 2016, the ratio of Total Secured Debt to EBITDA was 0.21 to 1.00, the Current Ratio was 3.27 to 1.00 and the ratio of EBITDA to Interest Expense was 4.58 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 borrowing outstanding under the credit agreement are impacted by the timing of cash flows from operations, capital expenditures, acquisitions and dispositions 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, mergers, asset dispositions, 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).

7.50% Senior Notes due 2020 and 6.25% Senior Notes due 2023

Since September 15, 2016, the Company has had the right to redeem all or a portion of the 7.50% Senior Notes at redemption prices decreasing from 103.75% to 100% of the principal amount on September 15, 2018, plus accrued and unpaid interest.

Before April 15, 2018, the Company may, at its option, redeem all or a portion of 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 7.50% Senior Notes and the 6.25% Senior Notes) occurs, the Company may be required by holders to repurchase the 7.50% Senior Notes and the 6.25% Senior Notes for cash at a price equal to 101% of the principal amount, plus any accrued and unpaid interest.

The indentures governing 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, 2016, the 7.50% Senior Notes and the 6.25% Senior Notes are guaranteed by the same subsidiaries that also guarantee the revolving credit facility.

8.625% Senior Notes due 2018

On April 14, 2015, the Company settled a cash tender offer for any or all of the outstanding $600.0 million aggregate principal amount of its 8.625% Senior Notes, which expired on April 23, 2015. On April 28, 2015, the Company made an aggregate cash payment of $276.4 million for the $264.2 million aggregate principal amount of 8.625% Senior Notes validly tendered in the tender offer. This represented a tender offer premium totaling $12.2 million, equal to $1,046.13 for each $1,000 principal amount of 8.625% Senior Notes validly tendered and accepted for payment pursuant to the tender offer. In addition, all 8.625% Senior Notes accepted for payment received accrued and unpaid interest of $0.8 million from the last interest payment date up to, but not including, the settlement date.

In connection with the cash tender offer, the Company also sent a notice of redemption to the trustee for its 8.625% Senior Notes to conditionally call for redemption on May 14, 2015 all of the 8.625% Senior Notes then outstanding, conditioned upon and subject to the Company receiving specified net proceeds from one or more securities offerings, which conditions were satisfied. On May 14, 2015, the Company paid an aggregate redemption price of $352.6 million, including a redemption premium of $14.5 million, which represented 104.313% of the principal amount of the then outstanding 8.625% Senior Notes (or $1,043.13 for each $1,000 principal amount of the 8.625% Senior Notes) plus accrued and unpaid interest of $2.3 million from the last interest payment date up to, but not including, the redemption date, to redeem the then outstanding $335.8 million aggregate principal amount of 8.625% Senior Notes.

As a result of the cash tender offer and the redemption of the 8.625% Senior Notes, the Company recorded a loss on extinguishment of debt of $38.1 million during the second quarter of 2015, which includes the premium paid to repurchase the 8.625% Senior Notes of $26.7 million and non-cash charges of $11.4 million attributable to the write-off of unamortized debt issuance costs and the remaining discount associated with the 8.625% Senior Notes.

7. Asset Retirement Obligations

The following table sets forth asset retirement obligations for the years ended December 31, 2016 and 2015:

	Years Ended December 31,	
	2016	2015
	(In thousands)	
Beginning of year asset retirement obligations	$16,511	$12,512
Liabilities incurred	2,137	3,227
Increase due to acquisition of oil and gas properties	2,037	—
Liabilities settled	(599)	(1,966)
Accretion expense	1,364	1,112
Revisions to estimated cash flows	(210)	1,626
End of year asset retirement obligations	21,240	16,511
Current asset retirement obligations (included in other current liabilities)	(392)	(328)
Non-current asset retirement obligations	$20,848	$16,183

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 increases, 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, 2016, 2015 and 2014 was $2.0 million, $2.2 million, and $1.9 million, respectively, and includes rent expense for the Company's corporate office and field offices. At December 31, 2016, total minimum commitments from long-term, non-cancelable operating and capital leases, drilling rigs and minimum delivery commitments are as shown in the table below. The total minimum commitments related to the drilling rigs 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. The delivery commitments represent contractual obligations the Company has entered into for certain gathering, processing and transportation throughput commitments. The Company may incur volume deficiency fees from time to time if it elects to voluntarily curtail production due to market or operational considerations.

	2017	2018	2019	2020	2021	2022 and Thereafter	Total
	(In thousands)						
Operating leases	$4,438	$4,430	$4,412	$4,463	$4,450	$1,854	$24,047
Capital leases	1,856	1,823	1,800	1,050	—	—	6,529
Drilling rig contracts	23,753	3,957	—	—	—	—	27,710
Delivery commitments	8,134	8,611	7,298	4,826	3,680	291	32,840
Total	$38,181	$18,821	$13,510	$10,339	$8,130	$2,145	$91,126

9. Shareholders' Equity and Stock Based Compensation Plans

Common Stock Offerings

On October 28, 2016, the Company completed a public offering of 6.0 million shares of its common stock at a price of $37.32 per share, for proceeds of $223.7 million, net of offering costs. The Company used the net proceeds from the common stock offering to fund the Sanchez Acquisition and to repay borrowings under the revolving credit facility.

On October 21, 2015, the Company completed a public offering of 6.3 million shares of its common stock at a price of $37.80 per share, for proceeds of $238.8 million, net of offering costs. The Company used the net proceeds from the common stock offering 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 of $44.75 per share, for proceeds of $231.3 million, net of offering costs. The Company used the net proceeds from the common stock offering to repay a portion of the borrowings under the Company's revolving credit facility and for general corporate purposes.

Exercise of Warrants

On November 24, 2009, the Company entered into an agreement with an unrelated third party and its affiliate under which the Company issued 118,200 warrants to purchase shares of the Company's common stock. In May 2015, the holders of the warrants exercised all warrants outstanding on a "cashless" basis at an exercise price of $22.09 resulting in the issuance of 71,913 shares of the Company's common stock.

Stock-Based Compensation Plans

The Company has established the Incentive Plan of Carrizo Oil & Gas, Inc., as amended (the "Incentive Plan"), which authorizes the granting of stock options, SARs that may be settled in cash or common stock at the option of the Company, restricted stock awards, restricted stock units and performance share awards to employees and independent contractors. The Incentive Plan also authorizes the granting of stock options, restricted stock awards and restricted stock units to non-employee directors. On May 15, 2014, the Incentive Plan was amended and restated, to increase the number of shares available for issuance under the Incentive Plan. The Company may grant awards covering up to 10,822,500 shares (subject to certain limitations) under the Incentive Plan, and at December 31, 2016, there were 2,938,889 common shares remaining available for grant under the Incentive Plan.

The Company has also established the Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan ("Cash SAR Plan"). The Cash SAR Plan authorizes the granting of SARs to employees and independent contractors that may only be settled in cash.

Restricted Stock Awards and Units. The Company grants restricted stock awards and units to employees and independent contractors and grants restricted stock units to non-employee directors. Restricted stock awards are treated as issued and outstanding as of the grant date because the shares of common stock are issued in the name of employees, but held by the Company until the restrictions are satisfied. Rights to dividends or dividend equivalents may be extended to restricted stock awards discretion of the Compensation Committee of the Board of Directors, but are held by the Company during the vesting period and paid, without interest, within 10 days following the vesting. If restricted stock awards are forfeited, any dividends or dividend equivalents paid with respect to those restricted stock awards are also forfeited. Restricted stock units are not considered issued and outstanding until the shares of common stock are issued to the employee upon vesting. Restricted stock units are payable, at the Company’s option, either in shares of common stock or as a cash payment equivalent to the fair market value of a share of common stock on the vesting date.

Most restricted stock awards and units contain a service condition, and certain restricted stock units also contain performance conditions. The performance conditions have been met for all outstanding restricted stock units.
The table below summarizes restricted stock award and unit activity for the years ended December 31, 2016, 2015 and 2014:

	Restricted Stock Awards and Units	Weighted Average Grant Date Fair Value
For the Year Ended December 31, 2014		
Unvested restricted stock awards and units, beginning of period	1,444,867	$28.03
Granted	576,812	$48.64
Vested	(647,306)	$32.64
Forfeited	(38,691)	$32.89
Unvested restricted stock awards and units, end of period	1,335,682	$34.55
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

The aggregate fair value of restricted stock awards and units that vested during the years ended December 31, 2016, 2015 and 2014 was $26.3 million, $32.0 million and $37.3 million, respectively. As of December 31, 2016, unrecognized compensation costs related to unvested restricted stock awards and units was $17.3 million and will be recognized over a weighted average period of 1.8 years.
Stock Appreciation Rights. SARs can be granted to employees and independent contractors under the Incentive Plan or the Cash SAR Plan. SARs granted under the 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. The settlement amount upon exercise is calculated as the difference between the fair market value of common stock on the date of exercise and the fair market value of common stock on the grant date price multiplied by the number of SARs exercised. All SARs contain service and performance conditions. The performance conditions have been met for all outstanding SARs.

The table below summarizes the activity for SARs for the years ended December 31, 2016, 2015 and 2014:

	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, 2014					
Outstanding, beginning of period	1,086,231	$24.78			
Granted	—	—			
Exercised	(321,033)	$30.24			$7.8
Forfeited	—	—			
Outstanding, end of period	765,198	$22.49			
Exercisable, end of period	587,481	$20.78			
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			
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	2.4	$10.1	
Exercisable, end of period	350,840	$19.87	0.5	$6.2	

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. As of December 31, 2015, the liability for SARs outstanding was $7.0 million, which was classified as "Other current liabilities."

As of December 31, 2016, unrecognized compensation costs related to unvested SARs was $3.0 million and will be recognized over a weighted average period of 1.2 years.

The grant date fair value of the SARs was calculated using the Black-Scholes-Merton option pricing model that used the assumptions described below:

- Expected term - The expected term represents the period of time that SARs are expected to be outstanding, which is the grant date to the date of expected exercise. The expected term is based on historical exercises for various groups of employees and independent contractors.
- Expected volatility - The expected volatility represents the extent to which the market price of the Company's common stock price is expected to fluctuate between the grant date and the expected term of the SAR. The volatility of the Company's common stock is based on daily, historical volatility of the market price of the Company's common stock over a period of time equal to the expected term and ending on the grant date.
- Risk-free interest rate - The risk-free interest rate is based on the zero-coupon United States Treasury yield for the expected term at date of grant.
-

Dividend yield - The dividend yield on the Company’s common stock is assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.

No SARs were granted during the years ended December 31, 2015 and 2014. The following table summarizes the assumptions used to calculate the fair value of SARs granted during the year ended December 31, 2016:

	Year Ended December 31, 2016	
Expected term (in years)	3.93	
Expected volatility	45.1	%
Risk-free interest rate	1.3	%
Dividend yield	—	%
Grant date fair value	$9.88	

Performance Share Awards. The Company grants performance share awards to employees and independent contractors, where each performance share represents the value of one share of common stock. Performance share awards are payable, at the Company's option, either in shares of common stock or as a cash payment equivalent to the fair market value of a share of common stock on the vesting date. The number of performance shares that will vest ranges from zero to 200% of the 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 performance share awards also contain service and performance conditions. The performance conditions have been met for all performance share awards. The table below summarizes performance share award activity for the years ended December 31, 2016, 2015 and 2014:

	Performance Share Awards	Weighted Average Grant Date Fair Value
For the Year Ended December 31, 2014		
Unvested performance share awards, beginning of period	—	—
Granted	56,342	$68.15
Vested	—	—
Forfeited	—	—
Unvested performance share awards, end of period	56,342	$68.15
For the Year Ended December 31, 2015		
Unvested performance share awards, beginning of period	56,342	$68.15
Granted	56,517	$65.51
Vested	—	—
Forfeited	—	—
Unvested performance share awards, end of period	112,859	$66.83
For the Year Ended December 31, 2016		
Unvested performance share awards, beginning of period	112,859	$66.83
Granted	41,651	$35.71
Vested	—	—
Forfeited	—	—
Unvested performance share awards, end of period	154,510	$58.44

As of December 31, 2016, unrecognized compensation costs related to unvested performance share awards was $2.9 million and will be recognized over a weighted average period of 1.5 years. 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 Company's TSR relative to the TSR achieved by the specified industry peer group over the performance period results in the vesting of zero performance share awards.

The grant date fair value of the performance share awards was determined using the Monte Carlo simulation. The Monte Carlo simulation is based on random projections of stock price paths that are repeated numerous times to achieve a probabilistic assessment. The assumptions used in the Monte Carlo simulation are described below:

- Expected term - The expected term represents the period of time that the performance share awards will be outstanding, which is the grant date to the end of the performance period.
- Expected volatility - The expected volatility represents the extent to which the market price of the Company’s common stock price is expected to fluctuate between the grant date and the end of the performance period. The volatility of the

Company's common stock and the industry peer group is based on daily, historical volatility of the market price each company's common stock over a period of time equal to the expected term and ending on the grant date.

- Risk-free interest rate - The risk-free interest rate is based on the zero-coupon United States Treasury yield for the expected term at date of grant.
- Dividend yield - The dividend yield on the Company's common stock is assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.

The following table summarizes the assumptions used to calculate the fair value of the performance share awards granted during the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
	2016	2015	2014
Number of simulations	500,000	500,000	500,000
Expected term (in years)	3.01	2.89	2.97
Expected volatility	55.3 %	45.3 %	49.9 %
Risk-free interest rate	1.2 %	0.9 %	0.9 %
Dividend yield	— %	— %	— %
Grant date fair value	$35.71	$53.58	$53.96

Stock Options. The Company may grant stock options to employees, independent contractors and non-employee directors. Stock options can be settled, at the Company's option, either in shares of common stock or as a cash payment equivalent to the fair market value of a share of common stock on the exercise date. The fair market value of common stock on the date of exercise must not be less than the fair market value of the common stock on the date of grant. The table below summarizes the activity for stock options for the years ended December 31, 2016, 2015 and 2014:

	Stock Options	Weighted Average Exercise Prices	Weighted Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)	Cash Received from Exercises (In millions)	Tax Benefit Realized from Exercises (In millions)
For the Year Ended December 31, 2014						
Outstanding, beginning of period	36,353	$13.91				
Granted	—	—				
Exercised	(33,086)	$13.20		$1.3	$0.4	$0.4
Forfeited	—	—				
Expired	(834)	$27.25				
Outstanding, end of period	2,433	$19.02	0.5	$0.1		
Exercisable, end of period	2,433	$19.02	0.5	$0.1		
For the Year Ended December 31, 2015						
Outstanding, beginning of period	2,433	$19.02				
Granted	—	—				
Exercised	(2,433)	$19.02		$0.1	—	$0.1
Forfeited	—	—				
Outstanding, end of period	—	—	0	—		
Exercisable, end of period	—	—	0	—		

The Company last granted stock options in 2005 and the final exercise of outstanding stock options occurred during 2015.

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Stock-Based Compensation Expense, Net

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

	Years Ended December 31,		
	2016	2015	2014
	(In thousands)		
Restricted stock awards and units	$28,196	$23,668	$29,597
Stock appreciation rights	9,675	(6,326)	1,985
Performance share awards	2,806	1,961	1,395
	40,677	19,303	32,977
Less: amounts capitalized to oil and gas properties	(4,591)	(4,574)	(7,099)
Total stock-based compensation expense, net	$36,086	$14,729	$25,878

10. Related Party Transactions

Avista Joint Ventures. Effective August 2008, the Company's wholly owned subsidiary Carrizo (Marcellus) LLC entered into a joint venture arrangement with ACP II Marcellus LLC ("ACP II"), an affiliate of Avista Capital Partners, LP, a private equity fund. Effective September 2011, the Company's wholly-owned subsidiary, Carrizo (Utica) LLC, entered into a joint venture in the Utica with ACP II and ACP III Utica LLC ("ACP III"), an affiliate of ACP II and Avista Capital Partners, LP. (collectively with ACP II and ACP III, "Avista"). During the term of the Avista joint ventures, the joint venture partners acquired and sold acreage and the Company exercised options under the applicable Avista joint venture agreements to acquire acreage from Avista.

The Avista Utica joint venture agreements were terminated on October 31, 2013 in connection with the Company's purchase of certain ACP III assets. After giving effect to such transaction, the Company and Avista remain working interest partners in Utica with the Company acting as the operator of the jointly owned properties which are now subject to standard joint operating agreements. The joint operating agreements with Avista provide for limited areas of mutual interest around properties jointly owned by the Company and Avista.

Carrizo Relationship with Avista. Steven A. Webster, Chairman of the Company's Board of Directors, serves as Co-Managing Partner and President of Avista Capital Holdings, LP, which entity has the ability to control Avista and its affiliates. As previously disclosed, the Company has been and is a party to prior arrangements with affiliates of Avista Capital Holdings, LP.

The terms of the joint ventures with Avista in the Utica and the Marcellus and a related prior acquisition transaction were each separately approved by a special committee of the Company's independent, non-employee directors. In determining whether to approve or disapprove a transaction, such special committee has determined whether the transaction is desirable and in the best interest of the Company and has evaluated such transaction is fair to the Company and its shareholders on the same basis as comparable arm's length transactions. The committee has applied, and may in other transactions also apply, standards under relevant debt agreements if required.

Amounts due from Avista and Affiliates. As of December 31, 2016 and 2015, related party receivable on the consolidated balance sheets included $0.9 million and $2.4 million, respectively, representing the net amounts ACP II and ACP III owes the Company related to activity within the Avista Marcellus and Avista Utica joint ventures.

11. Derivative Instruments

The Company uses commodity derivative instruments to reduce its exposure to commodity price volatility for a portion of its forecasted crude oil and natural gas production and thereby achieve a more predictable level of cash flows to support the Company's drilling and completion capital expenditure program. The Company does not enter into derivative instruments for speculative or trading purposes. The Company's commodity derivative instruments may consist of fixed price swaps, costless collars, 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.

Costless Collars: A collar is a combination of options including a purchased put option (fixed floor price) and a sold call option (fixed ceiling price) and allows the Company to benefit from increases in commodity prices up to the fixed ceiling price and protect the Company from decreases in commodity prices below the fixed floor price. At settlement,

if the market price is below the fixed floor price or is above the fixed ceiling price, the Company receives the fixed price or pays the market price, respectively. If the market price is between the fixed floor price and fixed ceiling price, no payments are due from either party. These contracts are executed contemporaneously with the same counterparties and are premium neutral such that no premiums are paid to or received from the counterparties.
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 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. These contracts are executed contemporaneously with the same counterparties and are premium neutral such that no premiums are paid to or received from the counterparties.
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. In lieu of receiving payments for premiums from the counterparties, the Company uses the associated premium value to obtain a higher fixed price on fixed price swaps which are executed contemporaneously with the sold call options.
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. The payments of the premiums are deferred until the purchased call option contracts settle on a monthly basis. The Company purchases call options contemporaneously with sales of call options to increase the fixed price of existing sold call options and therefore are presented on a net basis in the summary of open crude oil derivative positions below.
The following sets forth a summary of the Company's crude oil derivative positions at average NYMEX prices as of December 31, 2016:

Period	Type of Contract	Crude Oil Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
Q1 2017	Fixed Price Swaps	12,000	$50.13	
Q2 2017	Fixed Price Swaps	12,000	$50.13	
Q3 2017	Fixed Price Swaps	6,000	$54.15	
Q4 2017	Fixed Price Swaps	3,000	$55.01	
FY 2018	Sold Call Options	2,488		$60.00
FY 2018	Net Sold Call Options	900		$75.00
FY 2019	Sold Call Options	2,975		$62.50
FY 2019	Net Sold Call Options	900		$77.50
FY 2020	Sold Call Options	3,675		$65.00
FY 2020	Net Sold Call Options	900		$80.00

The following sets forth a summary of the Company's natural gas derivative positions at average NYMEX prices as of December 31, 2016:

Period	Type of Contract	Natural Gas	Weighted Average	Weighted Average

		Volumes (in MMBtu/d)	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)
FY 2017	Fixed Price Swaps	20,000	$3.30	
FY 2017	Sold Call Options	33,000		$3.00
FY 2018	Sold Call Options	33,000		$3.25
FY 2019	Sold Call Options	33,000		$3.25
FY 2020	Sold Call Options	33,000		$3.50

The Company typically has numerous hedge positions that span several time periods and often result in both fair value asset and liability positions held with that counterparty, which positions are all offset to a single fair value asset or liability at the end of each reporting period, including the deferred premiums associated with its hedge positions. The Company nets its derivative

instrument fair values 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.
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 our 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' 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 or its counterparty parent company.
Derivative Assets and Liabilities
All derivative instruments are recorded on the Company's consolidated balance sheets as either an asset or liability measured at fair value. The combined derivative instrument fair value assets and liabilities recorded in the Company's consolidated balance sheets as of December 31, 2016 and 2015 is summarized below:

	December 31, 2016		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Derivative assets			
Derivative assets-current	$6,507	($5,270)	$1,237
Derivative assets-non current	1,313	(1,313)	—
Derivative liabilities			
Derivative liabilities-current	(27,871)	5,270	(22,601)
Derivative liabilities-non current	(28,841)	1,313	(27,528)
Total	($48,892)	$—	($48,892)

	December 31, 2015		
	Gross Amounts Recognized	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
	(In thousands)		
Derivative assets			
Derivative assets-current	$159,447	($28,347)	$131,100
Derivative assets-non current	10,780	(9,665)	1,115
Derivative liabilities			
Other current liabilities	(28,364)	28,347	(17)
Derivative liabilities-non current	(22,313)	9,665	(12,648)
Total	$119,550	$—	$119,550

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

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(Gain) Loss on Derivatives, Net

The Company has elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment. Therefore, all gains and losses as a result of changes in the fair value of derivative instruments are recognized as (gain) loss on derivatives, net in the Company's consolidated statements of operations in the period in which the changes occur. The effect of derivative instruments on the Company's consolidated statements of operations for the years ended December 31, 2016, 2015, and 2014 by commodity is summarized below:

	Years Ended December 31,		
	2016	2015	2014
	(In thousands)		
(Gain) Loss on Derivatives, Net			
Crude oil	$29,391	($95,199)	($191,351)
Natural gas	19,682	(4,062)	(10,556)
Total (Gain) Loss on Derivatives, Net	$49,073	($99,261)	($201,907)

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, 2016 and 2015:

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

	December 31, 2015		
	Level 1	Level 2	Level 3
	(In thousands)		
Derivative assets	$—	$132,215	$—
Derivative liabilities	$—	($8,239)	$—

The Company uses Level 2 inputs to measure the fair value of the Company's commodity derivative instruments 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 and volatility factors. 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 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. The

Company typically has numerous hedge positions that span several time periods and often result in both derivative assets and liabilities with the same counterparty, which positions are all offset to a single derivative asset or liability in the consolidated balance sheets, including the deferred premiums associated with its hedge positions. The Company nets the fair values of its derivative assets and liabilities associated with derivative instruments 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. The Company had no transfers into Level 1 and no transfers into or out of Level 2 for the years ended December 31, 2016 and 2015.

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

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using a discounted cash flow model based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of 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” for further discussion of the Company’s acquisitions.

The fair value measurements of asset retirement obligations are measured on a nonrecurring basis when a well is drilled or acquired or when production equipment and facilities are installed or acquired using a discounted cash flow model based on inputs that are not observable in the market and therefore represent 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, 2016 and 2015.

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 classified 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 debt premiums and debt issuance costs, with the fair values measured using Level 1 inputs based on quoted secondary market trading prices.

	December 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
7.50% Senior Notes due 2020	$593,447	$624,750	$592,203	$528,000
6.25% Senior Notes due 2023	$640,546	$672,750	$639,389	$533,000
Other long-term debt due 2028	$4,425	$4,419	$4,425	$4,182

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, 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
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

	December 31, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$2,578,034	$52,067	$—	($2,397,919)	$232,182
Total property and equipment, net	44,499	1,671,774	3,059	(2,471)	1,716,861
Investment in subsidiaries	(815,836)	—	—	815,836	—
Other assets	74,679	156	—	(16,632)	58,203
Total Assets	$1,881,376	$1,723,997	$3,059	($1,601,186)	$2,007,246
Liabilities and Shareholders' Equity					
Current liabilities	$161,792	$2,521,572	$3,059	($2,400,939)	$285,484
Long-term liabilities	1,260,200	18,261	—	(753)	1,277,708
Total shareholders' equity	459,384	(815,836)	—	800,506	444,054
Total Liabilities and Shareholders' Equity	$1,881,376	$1,723,997	$3,059	($1,601,186)	$2,007,246

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(In thousands)

	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)

	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)

	Year Ended December 31, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$3,938	$706,121	$128	$—	$710,187
Total costs and expenses	(76,531)	442,343	30	(5,865)	359,977
Income from continuing operations before income taxes	80,469	263,778	98	5,865	350,210
Income tax expense	(28,164)	(92,322)	—	(7,441)	(127,927)
Equity in income of subsidiaries	171,554	—	—	(171,554)	—
Income from continuing operations	$223,859	$171,456	$98	($173,130)	$222,283
Income from discontinued operations, net of income taxes	4,060	—	—	—	4,060
Net income	$227,919	$171,456	$98	($173,130)	$226,343

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

	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

	Year Ended December 31, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($132,683)	$634,970	($12)	$—	$502,275
Net cash used in investing activities from continuing operations	(305,718)	(906,509)	(37,609)	309,160	(940,676)
Net cash provided by financing activities from continuing operations	300,290	271,539	37,621	(309,160)	300,290
Net cash used in discontinued operations	(8,490)	—	—	—	(8,490)
Net decrease in cash and cash equivalents	(146,601)	—	—	—	(146,601)
Cash and cash equivalents, beginning of year	157,439	—	—	—	157,439
Cash and cash equivalents, end of year	$10,838	$—	$—	$—	$10,838

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14. Supplemental Cash Flow Information

Supplemental cash flow disclosures and non-cash investing and financing activities are presented below:

	Years Ended December 31,		
	2016	2015	2014
	(In thousands)		
Supplemental cash flow disclosures:			
Cash paid for interest, net of amounts capitalized	$75,231	$64,692	$49,379
Cash paid for income taxes	—	—	—
Non-cash investing and financing activities:			
Increase (decrease) in capital expenditure payables and accruals	($21,492)	($86,878)	$45,716
Liabilities assumed in connection with the Sanchez Acquisition	4,880	—	—
Stock-based compensation expense capitalized to oil and gas properties	4,591	4,574	7,099
Asset retirement obligations capitalized to oil and gas properties	1,927	4,853	4,545
Purchase price adjustments related to the Eagle Ford Shale Acquisition	—	—	3,197
EFM deferred purchase payment	—	—	148,900
Other non-cash investing activities [1]	10,068	22,562	2,244

(1) Other non-cash investing activities primarily includes property exchanges and capital lease transactions.

15. 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,		
	2016	2015	2014
	(In thousands)		
Property acquisition costs			
Proved properties	$90,661	$—	$183,633
Unproved properties	113,535	63,446	215,021
Total property acquisition costs	204,196	63,446	398,654
Exploration costs	37,508	117,227	194,956
Development costs	374,134	389,396	530,268
Total costs incurred	$615,838	$570,069	$1,123,878

Costs incurred exclude capitalized interest on unproved properties of $17.0 million, $32.1 million, and $34.5 million for the years ended December 31, 2016, 2015 and 2014, 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 $1.9 million, $4.9 million and $4.5 million for the years ended December 31, 2016, 2015 and 2014, respectively. Non-cash additions related to the estimated future asset retirement obligations associated with the Sanchez Acquisition of $2.0 million are included in acquisition costs of proved properties for the year ended December 31, 2016. The internal cost of employee compensation and benefits, including stock-based compensation, capitalized to proved or unproved oil and gas properties of $10.5 million, $15.8 million and $18.8 million for the years ended December 31, 2016, 2015 and 2014, 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, 2016, 2015, and 2014 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, 2014	62,041	8,152	187,957	101,519
Extensions and discoveries	29,793	3,681	30,343	38,531
Revisions of previous estimates	3,046	1,270	18,913	7,469
Purchases of reserves in place	12,730	1,335	8,681	15,512
Production	(6,906)	(925)	(24,877)	(11,978)
December 31, 2014	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
Proved developed reserves:				
December 31, 2013	18,321	2,779	106,976	38,929
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
Proved undeveloped reserves:				
December 31, 2013	43,720	5,373	80,981	62,590
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

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 our 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 our drilling program and associated offset locations. Eagle Ford comprised 89% of the total extensions and discoveries.

For the year ended December 31, 2014, the Company added 5,483 MBoe of proved developed reserves and 33,048 MBoe of proved undeveloped reserves through our drilling program and associated offset locations. Eagle Ford comprised 92% of the total extensions and discoveries.

Revisions of previous estimates

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 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 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.

For the year ended December 31, 2014, revisions of previous estimates increased the Company's proved reserves by 7,469 MBoe. Included in revisions of previous estimates were positive revisions due to price primarily in Marcellus.

Purchases of reserves in place

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.

For the year ended December 31, 2014, purchases of reserves in place included 4,144 MBoe of proved developed reserves and 11,369 MBoe of proved undeveloped reserves associated with the Eagle Ford Shale Acquisition.

Standardized Measure

The standardized measure of discounted future net cash flows relating to proved reserves is as follows:

	December 31,		
	2016	2015	2014
	(In thousands)		
Future cash inflows	$5,903,629	$5,878,348	$10,380,951
Future production costs	(2,241,928)	(2,124,059)	(2,532,106)
Future development costs	(1,264,493)	(1,178,773)	(1,680,795)
Future income taxes (1)	—	—	(1,354,524)
Future net cash flows	2,397,208	2,575,516	4,813,526
Less 10% annual discount to reflect timing of cash flows	(1,093,779)	(1,210,292)	(2,258,444)
Standard measure of discounted future net cash flows	$1,303,429	$1,365,224	$2,555,082

(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 our 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 2016, 2015 and 2014 were $39.60, $47.24, and $92.24 per Bbl, respectively, for crude oil, $11.66, $12.00 and $27.80 per Bbl, respectively, for NGLs, and $1.89, $1.87 and $3.24 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 are based on year-end 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,		
	2016	2015	2014
	(In thousands)		
Standardized measure at beginning of year	$1,365,224	$2,555,082	$1,621,411
Revisions to reserves proved in prior years:			
Net change in sales prices and production costs related to future production	($346,763)	($2,547,213)	($240,533)
Net change in estimated future development costs	74,407	342,238	89,401
Net change due to revisions in quantity estimates	(150,245)	(157,271)	205,166
Accretion of discount	136,522	326,074	202,672
Changes in production rates (timing) and other	(111,137)	(139,533)	(61,099)
Total revisions to reserves proved in prior years	(397,216)	(2,175,705)	195,607
Net change due to extensions and discoveries, net of estimated future development and production costs	313,201	252,155	867,615
Net change due to purchases of reserves in place	43,426	—	352,867
Sales of crude oil, NGLs and natural gas produced, net of production costs	(320,272)	(312,213)	(598,036)
Previously estimated development costs incurred	299,066	340,247	415,963
Net change in income taxes [1]	—	705,658	(300,345)
Net change in standardized measure of discounted future net cash flows	(61,795)	(1,189,858)	933,671
Standardized measure at end of year	$1,303,429	$1,365,224	$2,555,082

(1) Net change in income taxes in the calculation of changes in standardized measure of discounted future net cash flows was zero as of December 31, 2016 as the 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. See discussion in the note above as to why 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.

16. Quarterly Financial Data (Unaudited)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2016 and 2015:

Year Ended December 31, 2016	First Quarter [(2)]	Second Quarter [(2)]	Third Quarter [(2)]	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
Loss from continuing operations	($311,395)	($262,126)	($101,174)	($779)
Net loss	($311,395)	($262,126)	($101,174)	($779)
Net loss per common share - basic				
Loss from continuing operations [(5)]	($5.34)	($4.46)	($1.72)	($0.01)
Net loss [(5)]	($5.34)	($4.46)	($1.72)	($0.01)
Net loss per common share - diluted				
Loss from continuing operations [(5)]	($5.34)	($4.46)	($1.72)	($0.01)
Net loss [(5)]	($5.34)	($4.46)	($1.72)	($0.01)

Year Ended December 31, 2015	First Quarter	Second Quarter [(3)]	Third Quarter [(4)]	Fourth Quarter [(4)]
	(In thousands, except per share data)			
Total revenues	$100,050	$123,494	$106,237	$99,422
Operating profit (loss) [(1)]	($2,588)	$14,034	($3,752)	$4,484
Loss from continuing operations	($21,476)	($46,970)	($708,768)	($380,671)
Net loss	($21,210)	($46,132)	($707,647)	($380,165)
Net loss per common share - basic				
Loss from continuing operations [(5)]	($0.46)	($0.92)	($13.75)	($6.73)
Net loss [(5)]	($0.46)	($0.90)	($13.73)	($6.72)
Net loss per common share - diluted				
Loss from continuing operations [(5)]	($0.46)	($0.92)	($13.75)	($6.73)
Net loss [(5)]	($0.46)	($0.90)	($13.73)	($6.72)

(1) Total revenues less lease operating expense, production taxes, ad valorem taxes and DD&A.

(2) 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.

(3) In the second quarter of 2015, the Company recognized a loss on extinguishment of debt of $38.1 million as a result of the cash tender offer and redemption of the 8.625% Senior Notes.

(4) In the third quarter and fourth quarter of 2015, the Company recognized impairments of proved oil and gas properties of $812.8 million and $411.6 million, respectively. Primarily as a result of the impairments of proved oil and gas properties, since the third quarter of 2015, the Company recorded a valuation allowance against its net deferred tax assets reducing them to zero.

(5) The sum of quarterly net loss per common share does not agree with the total year net loss per common share as each computation is based on the weighted average of common shares outstanding during the period.

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 27, 2017

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 27, 2017
/s/ David L. Pitts David L. Pitts	Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2017
/s/ Gregory F. Conaway Gregory F. Conaway	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2017
/s/ Steven A. Webster Steven A. Webster	Chairman of the Board	February 27, 2017
/s/ Thomas L. Carter, Jr. Thomas L. Carter, Jr.	Director	February 27, 2017
/s/ Robert F. Fulton Robert F. Fulton	Director	February 27, 2017
/s/ F. Gardner Parker F. Gardner Parker	Director	February 27, 2017
/s/ Roger A. Ramsey Roger A. Ramsey	Director	February 27, 2017
/s/ Frank A. Wojtek Frank A. Wojtek	Director	February 27, 2017