CARRIZO OIL & GAS INC
Form 10-K
February 25, 2015

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, 2014
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, 2014, the aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $2.9 billion based on the closing price of such stock on such date of $69.26.

At February 20, 2015, the number of shares outstanding of the registrant’s Common Stock was 46,133,626.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant's 2015 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, 2014.

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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 and results of wells we expect to drill and other exploration activities;
- our estimates regarding timing and levels of production;
- changes in reserves, acreage and working capital requirements;
- 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;
- the effects of competition on us;
- our future results of operations;
- our liquidity and our ability to finance our exploration and development activities, including accessibility of borrowings under our revolving credit facility, our borrowing base, and the result of any borrowing base redetermination;
- our planned expenditures, prospects budgeted 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, results, effects, availability of and results of new and existing joint ventures and sales transactions;
- 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 involve risks and uncertainties, including, but not limited to, those relating to the 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, 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, 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 our midstream and other industry partners, weather, actions by lenders, 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 partners, results of exploration activities, the availability and completion of land acquisitions, 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 Utica Shale in Ohio, the Niobrara Formation in Colorado and the Marcellus Shale in Pennsylvania.

The Company achieved record total production in 2014 of 12.0 MMBoe, a 20% increase from 2013. At year-end 2014, our U.S. proved reserves of 151.1 MMBoe were 67% crude oil, 9% natural gas liquids and 24% natural gas, as compared to 61%, 8% and 31% at year-end 2013, respectively. Our reserves increased primarily as a result of our ongoing drilling program, as well as the acquisition of additional leasehold and producing interests primarily in LaSalle, Atascosa, and McMullen counties, Texas in the Eagle Ford Shale.

The following table provides details about the Company’s proved reserves as of the dates indicated.

	Proved Reserves (MMBoe)	
	December 31, 2014	December 31, 2013
Eagle Ford	122.5	73.9
Niobrara	5.6	5.3
Utica	0.6	—
Marcellus	22.3	22.2
Other	0.1	0.1
Total	151.1	101.5

Our 2015 capital expenditure plan currently includes $450.0 million to $470.0 million for drilling and completion and $35.0 million for leasehold and seismic. This plan represents a decrease of approximately 42% from our 2014 capital expenditures and reflects our strategy of controlling capital costs and maintaining financial flexibility in a low commodity price environment. As discussed in this Annual Report on Form 10-K, our 2015 capital expenditure plan and our 2014 capital expenditures do not include amounts for the Eagle Ford Shale Acquisition described in “Crude Oil Plays and Projects—Eagle Ford” below. We currently expect to commit the majority of our 2015 capital expenditure plan to the continued development of our properties in the Eagle Ford, and to a lesser extent, Niobrara and Utica. We intend to finance our 2015 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.” Other available sources of funding include proceeds from the possible selective sale of assets, joint ventures and offerings of securities. Our capital expenditure plan has the flexibility to adjust should the low commodity price environment change. The table below summarizes our actual capital expenditures for 2014 and our planned capital expenditures for 2015:

	Capital Expenditures (In millions)	
	2015 Plan	2014 Actual
Drilling and completion		
Eagle Ford (1)	$377.0	$518.7
Niobrara	37.0	108.4
Utica	30.0	48.3
Marcellus	7.0	23.4
Other	9.0	16.6
Total drilling and completion (2)	460.0	715.4
Leasehold and seismic (1)	35.0	142.9
Total	$495.0	$858.3

(1) Does not include the Eagle Ford Shale Acquisition (as defined below).
(2) Represents the midpoint of our 2015 drilling and completion capital expenditure plan of $450.0 million to $470.0 million.

Summary of 2014 Proved Reserves, Drilling and Production by Area

	Eagle Ford	Niobrara	Utica	Marcellus	Other	Total
Proved reserves by product						
Crude oil (MMBbls)	96.0	4.4	0.2	—	0.1	100.7
NGLs (MMBbls)	12.8	0.6	0.1	—	—	13.5
Natural gas (Bcf)	81.8	3.8	1.7	133.5	0.2	221.0
Total proved reserves (MMBoe)	122.5	5.6	0.6	22.3	0.1	151.1
Proved reserves by classification (MMBoe)						
Proved developed	41.7	4.0	0.6	19.1	0.1	65.5
Proved undeveloped	80.8	1.6	—	3.2	—	85.6
Total proved reserves	122.5	5.6	0.6	22.3	0.1	151.1
Percent of total reserves	81%	4%	—	15%	—	100%
2014 production (MMBoe)	7.7	0.9	0.1	3.1	0.2	12.0
Percent of total production	64%	8%	1%	26%	1%	100%

	Eagle Ford		Niobrara		Utica		Marcellus		Other		Total	
Operated Well Data	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2014												
Wells drilled	69	58.0	32	13.0	3	2.2	3	1.2	1	1.0	108	75.4
Wells brought on production	73	58.7	38	15.1	2	1.4	19	5.1	1	1.0	133	81.3
As of December 31, 2014												
Wells waiting on completion	25	22.5	7	3.7	2	1.7	11	4.3	—	—	45	32.2
Wells producing	193	170.9	112	47.7	1	0.9	82	26.3	—	—	388	245.8

Crude Oil Plays and Projects

At December 31, 2014, our crude oil and NGL proved reserves were 114.2 MMBoe, a 63% increase from 70.2 MMBoe at December 31, 2013. The significant increase in crude oil and NGL reserves was primarily due to the execution of our ongoing drilling program in the Eagle Ford, as well as the Eagle Ford Shale Acquisition described in further detail below, together adding 43.4 MMBoe of crude oil and NGLs to our proved reserves (48.6 MMBoe including associated gas) during 2014.

Eagle Ford

The Eagle Ford Shale is our most significant operational area. Our core Eagle Ford properties are located in LaSalle County and, to a lesser extent, in McMullen, Frio and Atascosa counties in Texas. As of December 31, 2014, we held interests in approximately 111,539 gross (80,983 net) acres and we were operating three rigs in the Eagle Ford Shale. We currently expect to operate three rigs in the Eagle Ford throughout most of 2015. We are pleased with the performance of downspacing tests in the Eagle Ford and, as of December 31, 2014, approximately 65% of the approximately 936 net future oil-focused drilling locations in the Eagle Ford are 330-ft.-spaced locations. Based on our current estimates of drilling and completion costs, ultimate recoveries per well, differentials and operatingcosts, approximately 80% of our drilling locations are profitable at an oil price of $45.00 per Bbl.

On October 24, 2014, we completed the acquisition of approximately 6,820 net acres primarily in LaSalle, Atascosa, and McMullen counties, Texas from Eagle Ford Minerals, LLC (“EFM”) (such acquisition, the “Eagle Ford Shale Acquisition”). This acquisition had an effective date of October 1, 2014, with an adjusted purchase price of $241.8 million, which represents an agreed upon purchase price of $250.0 million, less working capital adjustments. We paid EFM approximately $93.0 million in cash at closing and $148.8 million on February 13, 2015. Prior to the acquisition, the Company and EFM were joint working interest owners in the acquired properties, for which we acted as the operator and owned an approximate 75% working interest. After giving effect to the acquisition, we hold an approximate 100% working interest in the acquired properties. For additional information see “Note 4. Eagle Ford Shale Acquisition” of the Notes to our Consolidated Financial Statements.

GAIL Joint Venture. As of December 31, 2014, approximately 27,009 net acres are subject to our September 2011 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 Shale 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. The consideration paid by GAIL at closing was $63.7 million in cash and a commitment, since satisfied, to pay 50% of certain of our development costs totaling approximately $31.3 million net to our interest. We generally serve as operator of the GAIL joint venture properties.

Niobrara

As of December 31, 2014, we held interests in approximately 101,730 gross (35,940 net) acres in the Niobrara, primarily in Weld and Adams counties, Colorado, and were operating one rig. During 2014, we participated in 71 gross (4.0 net) additional wells as a non-operator. We currently expect to continue to participate as a non-operator in high-density projects in the Niobrara. Based on our current estimates of drilling and completion costs, ultimate recoveries per well, differentials and operating costs, locations in the core portion of our Niobrara acreage position are profitable at an oil price of $57.00 per Bbl.

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.

During 2012 and 2013, the OIL JV Partners paid $41.3 million in cash at closing and $41.3 million of our development costs on certain properties in which such partners acquired interests from us. We 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% the OIL JV Partners, and 10% Haimo.

We serve as operator of the properties covered by our Niobrara joint venture arrangements. As of December 31, 2014, approximately 56,368 acres (net to the joint venture) in the Niobrara Formation were subject to our Niobrara joint venture arrangements.

Utica

We continued our emphasis in exploring for and developing crude oil and NGL plays through our acquisition of interests in the Utica Shale. As of December 31, 2014, we held interests in approximately 40,699 gross (27,140 net) acres in the Utica. In the first quarter of 2014, we brought our initial Utica well, the Rector 1H in Guernsey County, Ohio, online, and subsequently shut-in the well pending completion of pipeline facilities. We expect to bring the Rector 1H back online in 2015 once midstream infrastructure is in place. The second Utica well, the Brown 1H in Guernsey County, Ohio, was brought online in the first quarter of 2015. After an extended well test we intend to also shut-in this well until midstream infrastructure is completed. We have also drilled an additional two wells in the Utica and completed hydraulically fracturing them in the first quarter of 2015. These wells are currently “resting” and we expect to put on extended well tests later in 2015. In addition, we have drilled and cased the upper portions of 16 additional wells. We do not expect to complete the drilling of these wells until oil prices recover and midstream infrastructure is under construction. As of December 31, 2014, we were operating one rig in the Utica, which was released in the first quarter of 2015. During 2014, we participated in 9 gross (0.3 net) additional wells as a non-operator.

Avista Utica Joint Venture. Effective September 2011, our wholly-owned subsidiary, Carrizo (Utica) LLC, entered into a joint venture in the Utica Shale with ACP II Marcellus LLC (“ACP II”), which is also one of our joint venture partners in the Marcellus Shale, and ACP III Utica LLC (“ACP III”), both affiliates of Avista Capital Partners, LP, a private equity fund (collectively with ACP II and ACP III, “Avista”). 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 discussed below.
On October 31, 2013, we completed the acquisition of approximately 5,900 net acres located primarily in Guernsey and Noble counties, Ohio from Avista. This transaction had an effective date of July 1, 2013, and we paid Avista approximately $77.1 million in cash. Prior to the acquisition from ACP III, the properties in the Avista Utica joint venture were held on an equal basis by us and Avista. This transaction was initially funded with proceeds from the sale of our remaining oil and gas properties in the Barnett Shale. See also “Natural Gas Plays—Barnett” below. In connection with this transaction, we terminated the Avista Utica joint venture agreements described above. After giving effect to this transaction, we and Avista remain working interest partners in approximately 10,000 acres in the Utica net to us, 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 joint venture 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 acquisition of certain ACP III assets described above were each separately approved by a special committee of the Company's independent directors. See also "Natural Gas Plays—Marcellus—Avista Marcellus Joint Venture" below and "Note 11. Related Party Transactions" of the Notes to our Consolidated Financial Statements.

Delaware Basin

During 2014, we began to build an acreage position in the Delaware Basin in Culberson and Reeves counties, Texas, targeting the Wolfcamp Shale formation. As of December 31, 2014, we held interests in approximately 33,839 gross (17,371 net) acres in the Delaware Basin. During 2014, we participated in 4 gross (0.2 net) wells as a non-operator. We are not currently operating any rigs in the Delaware Basin and have allocated only a minimal amount of capital to the play during 2015.

U.K. North Sea

We used a low cost entry business model in the U.K. North Sea that allowed us to acquire prospective acreage without initially making material capital commitments. This strategy led directly to the acquisition of our interest in the Huntington Field discovery located primarily on block 22/14b, where our wholly-owned subsidiary Carrizo UK Huntington Ltd ("Carrizo UK") owned a 15% non-operated working interest and certain overriding royalty interests. On February 22, 2013, we closed the sale of Carrizo UK to Iona Energy Inc. ("Iona Energy") for an agreed-upon price of $184.0 million, including the assumption and repayment by Iona Energy of the $55.0 million of borrowings outstanding under Carrizo UK's senior secured multicurrency credit facility as of the closing date. As of January 31, 2015, we held interests in three licenses in the U.K. North Sea and had no material committed work obligations for which we were obligated to expend funds associated with these three licenses.

Natural Gas Plays

At December 31, 2014, our natural gas proved reserves were 221.0 Bcf, an 18% increase from 188.0 Bcf at December 31, 2013. The increase in natural gas proved reserves was primarily related to the Eagle Ford Shale Acquisition in the fourth quarter of 2014 and the continued success of our Eagle Ford drilling program in 2014. Our natural gas production decreased to 24.9 Bcf (68.2 MMcf/d) in 2014, a 21% decrease from the 31.4 Bcf (86.1 MMcf/d) in 2013. The decrease in natural gas production was primarily related to the sale of oil and gas properties in the Barnett Shale in the fourth quarter of 2013, and partially offset by natural gas production from new wells in Eagle Ford and Marcellus in 2014. See "Barnett" below for additional information.

Marcellus

We began active participation in the Marcellus Shale in 2007. We leveraged the knowledge and experience that we gained in the Barnett Shale to effectively explore for and develop natural gas in the Marcellus. Our activities in the Marcellus are currently conducted through two joint ventures described below.

As of December 31, 2014, we held interests in approximately 99,639 gross (33,451 net) acres in the Marcellus Shale. As a result of the material decline in natural gas prices, we and our joint venture partners are carefully reviewing our development program and have reduced our planned spending in the Marcellus during 2015. We will continue to monitor prices and, consistent with our existing contractual commitments, may decrease our activity level and capital expenditures further, or may increase such activity, if natural gas prices so warrant. As of December 31, 2014, 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, for $13.1 million in cash and a commitment by Reliance to pay 75% of certain of our future drilling and completion costs up to approximately $52.0 million. As of

December 31, 2012, the development carry had been fully utilized. As described in "Avista Marcellus Joint Venture" below, simultaneously with the closing of our transaction with Reliance, 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 Avista. The joint venture properties are generally held 60% by Reliance and 40% by us. The Carrizo/Reliance joint venture agreement included approximately 28,451 net acres in northern and central Pennsylvania as of December 31, 2014. We have agreed to various restrictions on our ability to transfer our properties covered by the Reliance joint venture. Additionally, since the expiration of the Reliance development carry, 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 have also granted an option in favor of Reliance to purchase a 60% share of acreage purchased directly or indirectly by us after the closing. This option, which covers substantially all of Pennsylvania, is exercisable at our cost plus, in the case of direct property sales, a specified premium, and is subject to specified exceptions. We 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. Operations under the Reliance joint venture will generally be required to conform to a budget approved by an operating committee that includes representatives of both parties, subject to exceptions, including those for sole risk operations and in the event of defaults by the parties. The parties have also generally agreed to certain restrictions regarding sole risk operations and other operations.

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. 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 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 for a purchase price of approximately $327.0 million. 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 joint venture with Avista continues and now covers approximately 14,052 net acres, 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 serve as operator of the properties covered by the Avista Marcellus joint venture. An operating committee composed of one representative of each party provides overall supervision and direction of joint operations. We conducted no material activity under this joint venture during 2014 and do not currently expect to conduct any activity in 2015. Avista or its designee has the right to become a co-operator of the Avista Marcellus joint venture properties if all of its membership interests or substantially all of its assets are sold to an unaffiliated third party or if we default under the terms of any pledge of our interest in the properties.

Each party has the ability to transfer its interest in the Avista Marcellus joint venture to third parties; subject in most instances to preferential purchase rights for transfers of less than 10% of a party's interest in joint venture properties, and to "tag along" rights for most other transfers. See "Note 11. Related Party Transactions" of the Notes to our Consolidated Financial Statements.

Barnett

We operated in the Barnett Shale from 2003 until the fourth quarter of 2013. In April 2012, we sold a substantial portion of our Barnett properties to an affiliate of Atlas Resource Partners, L.P. ("Atlas"). Net proceeds received from the sale were approximately $187.1 million, which represents an agreed upon purchase price of approximately $190.0 million less net purchase price adjustments.

On October 31, 2013, we sold substantially all of our remaining oil and gas properties in the Barnett to EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., EnerVest Energy Institutional Fund XIII-WIC, L.P., and EV Properties, L.P., (collectively, "EnerVest"). Net proceeds received from the sale were approximately $191.8 million, which represents an agreed upon purchase price of approximately $218.0 million less net purchase price adjustments.

Business Strategy

Measured Growth Through the Drillbit

Our objective is to increase value through the execution of a business strategy focused on organic growth through the drillbit. Key elements of our business strategy include:

- Grow primarily through drilling. We pursue a manufacturing-style development drilling program. We seek to identify resource plays through our extensive experience with the help of geological and geophysical analysis of 3-D seismic and other data and then accumulate sizeable acreage positions in high-quality areas. This provides us with the scale to drive efficiencies through our operations and improve our margins. Our ability to successfully identify, define and develop resource plays is demonstrated by our consistent success in rapidly growing oil and gas reserves and production in our oil and gas focused plays.

- 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, proceeds, payments or carried interest from our joint ventures and borrowings under our revolving credit facility.

- 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, the majority of our capital expenditure plan is discretionary allowing us the ability to reduce or reallocate our spending in response to changes in market conditions. For example, we have reduced our 2015 capital expenditure plan by approximately 42% from our 2014 capital expenditures, which reflects our strategy of maintaining financial flexibility in a low commodity price environment.
- 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 reductions in commodity prices by actively hedging production of both crude oil and natural gas. Our current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 36 months.
- Pursue growth in crude oil plays. Since April 2010, we have pursued a growth strategy in crude oil plays driven by the attractive relative economics associated with this commodity. By focusing on and implementing this strategy, our crude oil production as a percentage of total production has increased significantly from 3% for the year ended December 31, 2010 to 58% for the year ended December 31, 2014, which resulted in a significant increase in crude oil revenue as a percentage of total revenues from 10% for the year ended December 31, 2010 to 86% for the year ended December 31, 2014. Additionally, over 95% of our 2015 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.
- Utilize our experience as a technical advantage. We believe we have developed a technical advantage from our extensive experience drilling over 700 horizontal wells in various resource plays, including the Eagle Ford, 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. We now leverage this advantage in our existing as well as prospective shale trends. We plan to focus substantially all of our capital expenditures in these resource plays, particularly during 2015, in the Eagle Ford where we have acquired, or are acquiring significant acreage positions and hold a large prospect inventory.

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, Niobrara, and Utica. As of December 31, 2014, we owned leases covering approximately 253,968 gross (144,063 net) acres in these areas. Approximately 57% of our estimated U.S. proved reserves at December 31, 2014 were undeveloped.
- 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 executed multiple joint ventures, 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.
- Operational control. As of December 31, 2014, we operated approximately 90% of the wells in Eagle Ford in which we held an interest. We held an average interest of approximately 89% in these operated wells. Our significant operational control 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. We are generally able to adjust drilling plans in response to changes in commodity prices.

- Financial flexibility to fund expansion. We maintain a financial profile that provides operational flexibility, and our capital structure provides us with the ability to execute our business plan. We believe that we have the ability and financial flexibility to fund the planned development of our assets through 2015.

Exploration 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.

Primarily due to the depressed levels of natural gas prices and the recent significant decline in oil prices, we sometimes seek to reduce costs by deferring drilling or completion activity or drilling more wells on units where we hold a lower working interest than our historic average. In addition, we have sought to enter into joint ventures with well-funded partners that will pay a disproportionate share of the drilling and completion costs of wells that we drill. In certain instances we may also seek to maximize the acreage that we can hold by drilling and producing by temporarily drilling fewer wells on each drilling unit in order to permit us to develop more drilling units with comparatively fewer rigs. Where possible, we also seek to maximize our liquidity, while increasing profitability of our projects through timing the completion and pipeline connection costs of our horizontal wells to coincide with periods of lower services costs.

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 frequently vertical wells, or 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, we have also shifted our focus toward crude oil to take advantage of 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 project generation and typically retain operator rights. Specific drill-sites are typically chosen by our own geoscientists or, in highly populated or environmentally sensitive areas, are dictated by available leases.

Operating Approach

Our management team has extensive experience in the development and management of exploration and development projects. We believe that the experience we have gained in the Barnett, Eagle Ford, Niobrara and Marcellus, along with our extensive experience in hydraulic fracturing and horizontal drilling technologies and the experience of our management 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 lease operator status 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, 2014, we operated 388 gross (245.8 net) productive oil and gas wells. We generally seek to control operations for most new exploration and development, taking advantage of our technical staff experience in horizontal drilling and hydraulic fracturing. For example, during 2014, we operated 69 of the 80 gross wells drilled in the Eagle Ford where we spent 73% of our 2014 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 depth, cost and 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.
Additional Oil and Gas Disclosures
Proved Oil and Gas Reserves
The following table sets forth our estimated net proved oil and gas reserves and the PV-10 value of such reserves as of December 31, 2014. The reserve data and the present value as of December 31, 2014 were prepared by Ryder Scott Company, L.P. For further information concerning the independent third party engineer’s estimates of our proved reserves at December 31,

2014, see the reserve report included as an exhibit to this Annual Report on Form 10-K. The PV-10 value was prepared using an unweighted arithmetic average of the first day of the month oil and gas prices for each month in the prior twelve-month period ended December 31, 2014, discounted at 10% per annum on a pre-tax basis, and is not intended to represent the current market value of the estimated oil and gas reserves owned by us. For further information concerning the present value of future net revenues from these proved reserves, see “Note 2. Summary of Significant Accounting Policies” and “Note 17. Supplemental Disclosures About Oil and Gas Producing Activities (Unaudited)” of the Notes to our Consolidated Financial Statements. As part of the Eagle Ford Shale Acquisition, we acquired approximately 15.5 MMBoe of proved reserves in the Eagle Ford.

Summary of Proved Oil and Gas Reserves as of December 31, 2014
Based on Average 2014 Prices
(Dollars in millions)

	Crude Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Total (MBoe) (1)	PV-10 Value (2)
Developed	35,238	5,294	149,697	65,482	$1,616.2
Undeveloped	65,466	8,218	71,320	85,571	$1,644.5
Total Proved	100,704	13,512	221,017	151,053	$3,260.7

(1) Barrel of oil equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or one Bbl of natural gas liquids which represents their approximate energy content. Despite holding this ratio constant at six Mcf to one Bbl, current prices are 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.

(2) The PV-10 value as of December 31, 2014 is pre-tax and was determined by using the average of oil and gas prices at the beginning of each month in the twelve-month period prior to December 31, 2014, which averaged $92.24 per Bbl of oil, $27.80 per Bbl of natural gas liquids, and $3.24 per Mcf of natural gas. We believe that the presentation of a pre-tax PV-10 value provides relevant and useful information because it 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. Because many factors that are unique to each individual company may impact the amount and timing of future income taxes, the use of a pre-tax PV-10 value provides greater comparability when evaluating oil and gas companies. The PV-10 value is not a measure of financial or operating performance under U.S. GAAP, nor is it intended to represent the current market value of proved oil and gas reserves. The definition of PV-10 value 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, the PV-10 value as defined may not be comparable to similar measures provided by other companies. The most comparable U.S. GAAP financial measure, the standardized measure of future net cash flows, and information reconciling the U.S. GAAP and non-U.S. GAAP measures are included in the table below.

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

	As of December 31, 2014 (In millions)
Standardized measure of discounted future net cash flows (U.S. GAAP)	$2,555.1
Add: present value of future income taxes discounted at 10% per annum	$705.6
PV-10 value (Non-U.S. GAAP)	$3,260.7

Proved Undeveloped Reserves

At December 31, 2014 and 2013, we had 85.6 MMBoe and 62.6 MMBoe of proved undeveloped reserves, respectively. In 2014, we added 33.0 MMBoe of proved undeveloped reserves, of which approximately 88% were crude oil and NGLs, which included 32.3 MMBoe and 0.7 MMBoe of proved undeveloped reserves as a result of drilling and additional offset locations in the Eagle Ford and Marcellus, respectively. During 2014, we converted 22.0

MMBoe of reserves from proved undeveloped to proved developed, primarily in the Eagle Ford and Marcellus at a cost of approximately $416.0 million compared to 11.9 MMBoe converted during 2013 at a cost of approximately $217.4 million. We spent an additional $67.0 million on proved undeveloped reserves that were added in 2014, $45.7 million of which was spent on locations that were converted within the year and $21.3 million of which was spent on locations that were drilled but waiting on completion. Revisions of proved undeveloped reserves totaled 0.6 MMBoe, primarily due to an increase in the estimated ultimate recovery of our Eagle Ford proved undeveloped reserves due to longer estimated laterals. As part of the Eagle Ford Shale Acquisition, we acquired approximately 11.4 MMBoe of proved undeveloped reserves in the Eagle Ford.

At December 31, 2014, we did not have any reserves that have remained undeveloped for five or more years and all proved undeveloped reserves drilling locations are currently scheduled to be drilled within three to five years of their initial booking.

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 Securities and Exchange Commission (“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.” All of our proved reserves as of December 31, 2014, have been determined by Ryder Scott Company, L.P., independent third party reserve engineers.

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.”

In accordance with SEC regulations, Ryder Scott Company, L.P. and our internal reserve engineer each used the price based on the unweighted average of benchmark oil and gas prices at the beginning of each month in the twelve-month period ended December 31, 2014, adjusted for basis and quality differentials. 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 subsequent to December 31, 2014. As a result of significant decreases in commodity prices, the average prices used to calculate PV-10 value as of December 31, 2014 are significantly higher than recent prices. 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.

Qualifications of Third Party Reserve Engineers

As discussed above, we engaged Ryder Scott Company, L.P., independent third party reserve engineers, to perform independent estimates of our proved reserves. The technical person responsible for review of our reserve estimates meets 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 Company, L.P. does not own an interest in our properties and is not employed on a contingent fee basis.

Internal Controls

A significant component of our internal controls in our reserve estimation effort is our practice of using an independent third party reserve engineering firm to determine our year-end reserves. The qualifications of this firm are discussed above under “Qualifications of Third Party Reserve Engineers.”

Our internal reserve engineer is an individual at the Company who is primarily responsible for reviewing the reserves estimates prepared by our third party engineering firm. This individual has 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.

This individual, along with other Company personnel, review the inputs and assumptions made in the reserve estimates prepared by the independent third party reserve engineering firm and assess them for reasonableness. 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 from the University of Colorado, and the Chief Operating Officer, who holds a B.S. in Petroleum Engineering from Texas A&M University.

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.

	Year Ended December 31,		
	2014	2013	2012
Total production volumes -			
Crude oil (MBbls)	6,906	4,231	2,862
NGLs (MBbls)	926	531	305
Natural gas (MMcf)	24,877	31,422	37,612
Total Natural gas and NGLs (MMcfe)	30,433	34,608	39,442
Total barrels of oil equivalent (MBoe)	11,978	9,999	9,436
Daily production volumes by product -			
Crude oil (Bbls/d)	18,921	11,592	7,820
NGLs (Bbls/d)	2,537	1,455	833
Natural gas (Mcf/d)	68,156	86,088	102,765
Total Natural gas and NGLs (Mcfe/d)	83,378	94,816	107,765
Total barrels of oil equivalent per day (Boe/d)	32,816	27,395	25,781
Daily production volumes by region (Boe/d) -			
Eagle Ford	21,131	12,628	7,950
Niobrara	2,585	1,724	1,259
Barnett	—	6,625	11,614
Marcellus	8,354	6,139	3,608
Utica and other	746	279	1,350
Total barrels of oil equivalent (Boe/d)	32,816	27,395	25,781
Average realized prices -			
Crude oil ($ per Bbl)	$88.40	$99.58	$99.97
NGLs ($ per Bbl)	$27.05	$29.25	$34.86
Natural gas ($ per Mcf)	$3.00	$2.65	$1.90
Total Natural gas and NGLs ($ per Mcfe)	$3.28	$2.86	$2.08
Total average realized price ($ per Boe)	$59.29	$52.02	$39.02
Average production costs ($ per Boe)(1)	$6.19	$4.68	$3.34

(1) Includes lease operating costs but excludes production tax and ad valorem tax.

Drilling Activity

The following table sets forth our drilling activity for the years ended December 31, 2014, 2013 and 2012 by geographical area. 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.

	Year Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
U.S.						
Exploratory Wells - Productive	128	23.0	75	13.9	69	31.8
Exploratory Wells - Nonproductive	—	—	2	2.0	1	0.5
Development Wells - Productive	77	63.5	119	64.6	60	37.7
Development Wells - Nonproductive	—	—	—	—	—	—
U.K. North Sea						
Exploratory Wells - Productive	—	—	—	—	—	—
Exploratory Wells - Nonproductive	—	—	—	—	1	0.2
Development Wells - Productive	—	—	—	—	2	0.3
Development Wells - Nonproductive	—	—	—	—	—	—
Worldwide						
Exploratory Wells - Productive	128	23.0	75	13.9	69	31.8
Exploratory Wells - Nonproductive	—	—	2	2.0	2	0.7
Development Wells - Productive	77	63.5	119	64.6	62	38.0
Development Wells - Nonproductive	—	—	—	—	—	—

The wells are in various stages of development or stages of production.

As of December 31, 2014, we were in the process of drilling 7 gross (5.7 net) wells in the United States that are not included in the table above.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned an interest as of December 31, 2014.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	297	212.3	144	11.0	441	223.3
Natural gas	91	33.5	27	3.0	118	36.5
Total	388	245.8	171	14.0	559	259.8

As of December 31, 2014, we did not have any producing wells in the U.K. North Sea. For further information concerning the sale of the U.K. North Sea assets see “Note 3. Discontinued Operations” of the Notes to our Consolidated Financial Statements.

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2014. Developed acreage refers to acreage on which wells have been drilled or 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	
	Gross	Net	Gross	Net	Gross	Net
U.S.						
Eagle Ford - Texas	57,010	47,674	54,529	33,309	111,539	80,983
Niobrara - Colorado	34,948	12,975	66,782	22,965	101,730	35,940
Utica - Ohio	716	503	39,983	26,637	40,699	27,140
Delaware Basin - Texas	960	120	32,879	17,251	33,839	17,371
Marcellus						
Pennsylvania	14,030	5,250	45,369	14,557	59,399	19,807
Other-Marcellus	2,303	236	37,937	13,408	40,240	13,644
Marcellus Total	16,333	5,486	83,306	27,965	99,639	33,451
Other U.S. (1)	5,461	3,995	167,024	126,259	172,485	130,254
Total U.S.	115,428	70,753	444,503	254,386	559,931	325,139
U.K. North Sea (discontinued operations)	—	—	139,924	103,227	139,924	103,227
Worldwide	115,428	70,753	584,427	357,613	699,855	428,366

(1) "Other U.S." includes acreage principally located in Colorado, Wyoming, Texas and Appalachia, where the Company does not currently intend to spend material sums.

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). If no production is established on our leases that are in their primary term, approximately 16% of our acreage will expire in 2015, 21% will expire in 2016 and 27% will expire in 2017. The reserves associated with the acreage expiring over the next three years are not material to the Company.

Marketing

Our production is marketed to third parties consistent with industry practices. Typically, our oil and gas is sold at the wellhead to unaffiliated third parties. Oil is sold at field-posted prices plus or minus a bonus or at a price based on NYMEX plus or minus a differential for the area. Natural gas is 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-3, 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 sales point, 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 in natural gas pipeline operation, natural gas marketing and sales. In each case, we sell at competitive market prices based on a differential to several sales points. 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 production 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 lower oil and gas prices 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. We also conduct an active hedging program at a corporate level which generally is undertaken in order to ensure stable cash flow to fund our exploration and production activities. All of these hedging transactions provide for financial rather than physical settlement. For a discussion of these matters, our hedging policy and recent hedging positions, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Summary of Critical Accounting Policies—Derivative Instruments,” “Item 7A. Qualitative and Quantitative Disclosures About Market Risk—Commodity Risk,” “Item 1A. Risk Factors—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” 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.”

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 transportation and processing 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 Marcellus, 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.

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 2010, to implement the third of the required five-yearly re-determinations, the FERC established an upward adjustment in the index to track oil pipeline cost changes. For the five-year period beginning July 1, 2011, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. 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, in 2012 the Texas Commission on Environmental Quality revised certain air permit programs by significantly increasing the air permitting requirements for new and certain existing oil and gas production and gathering sites for 23 counties in the Barnett Shale production area. 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 finalized rules that establish new air emission control requirements for natural gas and natural gas liquids production, processing and transportation activities, including New Source Performance Standards (“NESHAPS”) to address emissions of sulfur dioxide and volatile organic compounds, and National Emission Standards for Hazardous Air Pollutants to address hazardous air pollutants frequently associated with gas production and processing activities. Among other things, these final rules require the reduction of volatile organic compound emissions from natural gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells constructed or refractured after January 1, 2015. In addition, gas wells are required to use completion combustion device equipment (i.e., flaring) by October 15, 2012 if emissions cannot be directed to a gathering line. Further, the final rules under NESHAPS include maximum achievable control technology (“MACT”) standards for “small” glycol dehydrators that are located at major sources of hazardous air pollutants and modifications to the leak detection standards for valves. In January 2015, the EPA announced that it plans to issue a rule governing methane emissions from oil and gas sources in Summer 2015. Compliance with these requirements, especially the imposition of these green completion 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 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.

Our historical and any future offshore operations in the U.K. North Sea are subject to similar regulations covering permit requirements and the discharge of oil and other contaminants in connection with drilling 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. On December 15, 2009, the EPA published a Final Rule, also known as the EPA's Endangerment Finding, finding that current and projected concentrations of six key GHGs in the atmosphere threaten the environment and public health and the welfare of current and future generations. Based on these findings, the EPA adopted two sets of regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another that 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, the EPA has announced its intention to issue a proposed rule in the summer of 2015 and a final rule in 2016 setting standards for methane and VOC emissions from new and modified oil and gas production sources.

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. Moreover, in 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for GHGs, became binding on all those countries that had ratified it. Ongoing international discussions following the United Nations Climate Change Conference in Doha, Qatar in December 2012 explored options to replace the Kyoto Protocol. The most recent United Nations Climate Change Conference was held in Lima, Peru, in December 2014, and discussed the development of a new agreement on climate change in late 2015.

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 or the North Sea 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; Acquisition Risks

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 at least 10% of our oil and gas revenues for each respective year:

	Year Ended December 31,		
	2014	2013	2012
Shell Trading (US) Company	44%	47%	(a)
Flint Hills Resources, LP	26%	23%	53%
Enterprise Products Operating, L.L.C.	(a)	(a)	10%

(a) Revenues from the customer were below 10% during the year.

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, 2014, we had 247 full-time employees. We believe that our relationships with our employees are satisfactory.

In order to optimize prospect generation and development, we utilize the services of independent consultants and contractors to perform various professional services, particularly in the areas of 3-D seismic data mapping, acquisition of leases and lease options, construction, design, well site surveillance, permitting and environmental assessment. Independent contractors generally provide field and on-site production operation services, such as pumping, maintenance, dispatching, inspection and testing. We believe that this use of third-party service providers has enhanced our ability to manage general and administrative expenses.

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. We make available on our website, through a direct link to the SEC’s website at www.sec.gov, free of charge, our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file such materials with, or furnish them 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.

You may also find information related to our corporate governance, board committees and company code of ethics at our website. Among the information you can find there is 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.”

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Glossary of Certain Industry Terms

The definitions set forth below shall apply to the indicated terms as used herein. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest multiple or power of ten.

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. Barrel of oil equivalent. A Boe is determined using the ratio of 6,000 cubic feet of natural gas to one Bbl of oil, condensate or natural gas liquids, which approximates the relative 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.

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 from 58.5 to 59.5 degrees 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 (i) recovered 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.

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Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.
Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.
Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition, or both. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.
Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.
Hydraulic fracturing. Hydraulic fracturing is a well stimulation process using a liquid (usually water with an amount of chemicals mixed in) that is forced into an underground formation under high pressure to open or enlarge fractures in reservoirs with low permeability to stimulate and improve the flow of hydrocarbons from these reservoirs. As the formation is fractured, a proppant (usually sand or ceramics) is pumped into the fractures to “prop” or keep them from closing after they are opened by the liquid. Hydraulic fracturing is an essential technology in shale reservoirs and other unconventional resource plays where nearly all wells are fractured 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 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.

PV-10 value. When used with respect to oil and gas reserves, present value, or PV-10, means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices calculated as the average oil and gas price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date, and without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted to a present value using an annual discount rate of 10%.

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.
"Tag along" rights. An agreement may provide that if one or more persons owning a majority (or some other specified portion) of certain interests desires to sell all (or some specified portion) of their interests in one or more related transactions, other owners of the same or similar interests have the "tag along" right to join in the sale.
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.
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.
Undeveloped oil and gas reserves. Reserves of any category 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 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 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.
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 lower oil and gas prices 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 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 natural gas prices led us to suspend or curtail drilling and other exploration activities for natural gas. More recently, oil prices have declined significantly. We are particularly dependent on the production and sale of oil and this recent 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:

- 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;
- 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. Recent price declines have caused us to significantly reduce our new 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. 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 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. Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Reserve estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Additionally, in recent years, there has been increased debate and disagreement over the classification of reserves, with particular focus on proved undeveloped reserves. The interpretation of SEC rules regarding the classification of reserves and their applicability in different situations remain unclear in many respects. Changing interpretations of the classification standards of reserves or disagreements with our interpretations could cause us to write-down reserves.

As of December 31, 2014, approximately 57% of our proved reserves were proved undeveloped. Moreover, some of the producing wells included in our reserve reports as of December 31, 2014 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 in the applicable year, with costs determined as of the date of the estimate. As a result of significant recent declines in commodity prices, such average sales prices are significantly in excess of more recent prices. Unless commodity prices or reserves increase, the estimated discounted future net cash flows from our proved reserves would generally be expected to decrease as additional months with lower commodity sales prices will be included in 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.
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 recent declines in oil 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.
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, development and acquisition programs. 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 Eagle Ford and Marcellus where we operate. See “—Interruption to crude oil and natural gas gathering systems, pipelines 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. Due to the limited available pipeline capacity in the Eagle Ford and Marcellus, 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 by oil and gas companies continues to expand 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 may not occur for lack of financing. In addition, capital constraints could limit our ability to build intrastate 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 onshore and offshore 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 may have impacts on our liquidity and financial condition that we currently cannot predict.
Instability in the global financial system 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 8.625% Senior Notes due 2018 and our 7.50% Senior Notes due 2020 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 8.625% Senior Notes and 7.50% 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 or redeeming our common stock, 8.625% Senior Notes and 7.50% Senior Notes, making investments, acquisitions, mergers and asset dispositions, entering into hedging transactions and other matters. Our revolving credit facility also requires compliance with covenants to maintain specified financial ratios. Our business plan and our compliance with these covenants are based on a number of assumptions, the most important of which is relatively stable oil and gas prices at economically sustainable levels. If the price that we receive for our oil and gas production further deteriorates from current levels or continues for an extended period, 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. 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. A prolonged period of decreased oil and gas prices or a further decline 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 recent 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 prevailing oil and gas prices. A negative adjustment could occur if the estimates of future 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 recent decline in oil prices or an expectation that such reduced prices will continue. The next redetermination of our borrowing base is scheduled to occur in Spring 2015. 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, without limitation, 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 less information regarding reserves and decline rates in this shale formation than in some other areas of our operations.

We have limited exploration and development experience in the Utica Shale. We have participated in the drilling of only 16 gross (4.1 net) wells in this area. Other operators in this area 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 Shale than we have in some other areas in which we operate.

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

We have limited exploration and development experience in the Delaware Basin. We have participated in the drilling of only 4 gross (0.2 net) wells in this area. Other operators in this area have significantly more experience in the drilling of wells, including the drilling of horizontal wells. As a result, we have less information with respect to the ultimate recoverable reserves, the production decline rate and other matters relating to the exploration, drilling and development of the Delaware Basin than we have in 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 treat and dispose of water after drilling, 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 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 October 2011, the EPA announced that it plans to develop standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works, which will be proposed in the first half of 2015. The regulations will be developed under the EPA’s Effluent Guidelines Program under the authority of the Clean Water Act. 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, Delaware Basin, Niobrara or Utica, 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 recent decline in oil prices, 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 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.

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

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and materials produced or used in connection with oil and gas operations, including drilling fluids and wastewater. 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 EPA's 2011-2016 National Enforcement Initiative, "Assuring Energy Extraction Activities Comply with Environmental Laws," through which 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 being paid 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 draft permitting guidance for hydraulic fracturing operations that use diesel fuel in fracturing fluids in those states where EPA is the permitting authority. 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, the EPA is conducting a comprehensive research study to investigate the potential adverse environmental impacts of hydraulic fracturing, including on water quality and public health. The EPA released a progress report outlining work currently underway on December 21, 2012 and is expected to release results of the study in early 2015. 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. President Obama has created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

Several other states, including states where we operate such as Colorado, Ohio, and Texas, have proposed or adopted legislative or regulatory restrictions on hydraulic fracturing through additional permit requirements, public disclosure of fracturing fluid contents, water sampling requirements, and operational restrictions. Further, some cities and municipalities have adopted or are considering adopting bans on drilling, including in Colorado, West Virginia, Texas and Pennsylvania. At the international level, the U.K. and EU Parliaments have each in the past discussed implementing a drilling moratorium in the U.K. North Sea. 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, Texas and Pennsylvania, 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 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 US. 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 offshore drilling, 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 onshore and offshore 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.

Offshore operations are subject to a variety of operating risks in addition to the hazards described above, such as capsizing and collisions. The occurrence of other events such as blowouts and oil spills in marine environments can make containment and remediation more difficult and costly than on land. These conditions can and have caused substantial damage to facilities and interrupted production in the past. Additionally, offshore operations generally involve increased costs and more expansive regulatory requirements as compared to onshore operations.

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 substantial 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 substantial 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 substantial 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 substantially 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 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. 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.

Our business may suffer if we lose key personnel.

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

We may experience difficulty in achieving and managing future growth.

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

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

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- 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, 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. 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. For example, we recently entered into derivative transactions offsetting our existing crude oil derivative positions covering the periods from March 2015 through December 2016. As a result, we locked in the cash flows to be received from those crude oil derivatives. Subsequently, we entered into costless collars for the periods from March 2015 through December 2016. As a result, we may not be as protected from further declines in oil prices as had been the case prior to such transactions. 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.

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.

During periods when oil and gas prices are relatively high, 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.

We may record impairments of oil and gas properties that would reduce our shareholders' equity.

We use the full cost method of accounting for our oil and gas properties. Accordingly, we capitalize all productive and nonproductive costs directly associated with property acquisition, exploration and development activities to cost centers established on a country-by-country basis. Under the full cost method, the capitalized cost of oil and gas properties, less accumulated amortization and related deferred income taxes may not exceed the "cost center ceiling" which is equal to the sum of the present value of estimated future net revenues from proved reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, plus the costs of properties not subject to amortization, plus the lower of the cost or estimated fair value of unproved properties included in the costs being amortized, less related income tax effects. If the net capitalized costs exceed the cost center ceiling, we recognize the excess as an impairment of oil and gas properties. This evaluation is performed on a quarterly basis. This impairment does not impact cash flows from operating activities but does reduce earnings and our shareholders' equity. The risk that we will be required to recognize impairments of our oil and gas properties increases during periods of low oil or gas prices. As a result, there is an increased risk that we will incur an impairment in 2015. 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." An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices increase the cost center ceiling applicable to the subsequent period. We have in the past and could in the future incur additional impairments of oil and gas properties, particularly as a result of a further decline in oil or gas prices. A continuation of the recently depressed levels of commodity prices or additional commodity price decreases will increase the likelihood of an impairment.

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. As of December 31, 2014, we believe an ownership change occurred in February 2005, which imposed an annual limitation of approximately $12.6 million of the Company's taxable income that can be offset by the pre-change carryforwards. Subsequent equity transactions involving us or our 5% shareholders (including, potentially, relatively small transactions and transactions beyond our control) could cause further ownership changes and therefore a limitation on the annual utilization of our U.S. loss carryforwards.

Enactment of proposed impact fees on natural gas wells could adversely impact our results of operations and the economic viability of exploiting natural gas drilling and production opportunities in Pennsylvania.

Legislation has been enacted in Pennsylvania, that authorizes counties to impose fees on certain natural gas wells in Pennsylvania. If a county elects to impose a fee, the fee will apply to any "unconventional gas well," which is generally defined as a well using hydraulic fracture treatments or multilateral well bores. Any county that elects not to impose the fee can be overruled by the municipalities within that county. The fee would be imposed over a fifteen year period, starting with the year the well is actually drilled and declining thereafter, and is based on natural gas prices and the Consumer Price Index. Unconventional gas wells drilled before the fee is imposed would still be subject to the fee and, for purposes of calculating the amount of the fee, will be considered to have been drilled in the calendar year prior to the imposition of the fee. A substantial portion of our Marcellus acreage and a portion of our Utica acreage is located in the Commonwealth of Pennsylvania. To the extent such fees are ultimately enacted by counties in which we now or may in the future operate, or if Pennsylvania adopts severance taxes or additional fees (such as a recent proposal of a five percent severance tax on national gas extraction operations), such actions could adversely impact our results of operations and the economic viability of exploiting natural gas drilling and production opportunities in Pennsylvania.

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.

We have risks associated with our foreign operations.

We currently own international property interests and we continue to evaluate and pursue new opportunities for international expansion in select areas. Ownership of property interests and production operations in areas outside the United States is subject to the various risks inherent in foreign operations. These risks may include:

- currency restrictions and exchange rate fluctuations;
- loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrection;
- increases in taxes and governmental royalties;
- renegotiation of contracts with governmental entities and quasi-governmental agencies;
- changes in laws and policies governing operations of foreign-based companies;
- labor problems; and
- other uncertainties arising out of foreign government sovereignty over our international operations.

Our international operations also may be adversely affected by the laws and policies of the United States affecting foreign trade, taxation and investment. In addition, if a dispute arises with respect to our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts of the United States.

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

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 hostilities may affect our operations in unpredictable ways, including the possibility that infrastructure facilities, including pipelines and gathering systems, production facilities, processing plants and refineries, could be targets of, or indirect casualties of, an act of terror, a cyber attack or electronic security breach, or an act of war.

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 4. Eagle Ford Shale Acquisition” and “Note 5. 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. The Company strongly disagrees with the verdict, believes that the plaintiffs’ claims are without merit, and has filed post-trial motions in the trial court. If necessary, the Company intends to appeal the judgment to the Twelfth Court of Appeals at Tyler, Texas and ultimately the Texas Supreme Court. The payment of damages per the judgment has been superseded by posting a bond in the amount of $25.0 million pending resolution of the appeals process (which could take an extended period of time).

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 a

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greement 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.

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 sales prices per share of our common stock on the NASDAQ Global Select Market for the periods indicated.

	High	Low
2013		
First Quarter	$27.33	$19.49
Second Quarter	29.89	22.90
Third Quarter	37.52	28.39
Fourth Quarter	47.87	37.42
2014		
First Quarter	$54.94	$39.78
Second Quarter	69.39	50.29
Third Quarter	70.49	53.05
Fourth Quarter	54.92	31.70

The closing market price of our common stock on February 20, 2015 was $52.26 per share. As of February 20, 2015, there were an estimated 153 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."

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 or Securities Exchange Act of 1934, except to 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, 2009 to December 31, 2014, 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, 2009, 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, 2009	$100	$100	$100
December 31, 2010	$130	$115	$116
December 31, 2011	$99	$117	$110
December 31, 2012	$79	$136	$115
December 31, 2013	$169	$180	$152
December 31, 2014	$157	$205	$135

We made no repurchases of our common stock in 2014.

On November 24, 2009, we entered into an agreement with an unrelated third party and its affiliate, which expired by its terms on May 31, 2011. Under such agreement, we issued warrants to purchase 31,983 shares of common stock in 2012. The warrants have an expiration date of August 21, 2017, an exercise price of $22.09, which may be exercised on a “cashless” basis and are subject to anti-dilution adjustments. The warrants were issued pursuant to an exemption from registration under §4(2) of the Securities Act of 1933, as amended.

See “Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder 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, 2014, has been derived from continuing operations 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."

	Year Ended December 31,				
	2014	2013	2012	2011	2010
	(In thousands, except per share data)				
Statements of Operations from Continuing Operations Data:					
Total revenues	$710,187	$520,182	$368,180	$202,167	$138,123
Costs and expenses					
Oil and gas operating	112,151	75,340	54,826	37,636	31,014
Depreciation, depletion and amortization	317,383	214,291	165,993	84,841	47,246
General and administrative	77,029	77,492	48,708	41,539	35,906
(Gain) loss on derivatives, net	(201,907)	18,417	(31,371)	(48,423)	(47,782)
Loss on extinguishment of debt	—	—	—	897	31,023
Interest expense, net	53,171	54,689	48,158	27,629	22,518
Loss on sale of oil and gas properties	—	45,377	—	—	—
Other (income) expense, net	2,150	(185)	(267)	(97)	(212)
Total costs and expenses	359,977	485,421	286,047	144,022	119,713
Income from continuing operations before income taxes	350,210	34,761	82,133	58,145	18,410
Income tax expense	(127,927)	(12,903)	(30,956)	(25,611)	(6,685)
Income from continuing operations	$222,283	$21,858	$51,177	$32,534	$11,725
Basic income from continuing operations per common share	$4.90	$0.54	$1.29	$0.83	$0.34
Diluted income from continuing operations per common share	$4.81	$0.53	$1.28	$0.82	$0.34
Basic weighted average common shares outstanding	45,372	40,781	39,591	39,077	33,861
Diluted weighted average common shares outstanding	46,194	41,355	40,026	39,668	34,305
Statements of Cash Flows from Continuing Operations Data:					
Net cash provided by operating activities from continuing operations	$502,275	$367,474	$253,071	$155,511	$94,416
Net cash used in investing activities from continuing operations	(940,676)	(509,885)	(465,151)	(250,068)	(264,115)
Net cash provided by financing activities from continuing operations	300,290	120,326	237,778	116,826	169,990
Other Cash Flows from Continuing Operations Data:					
Capital expenditures - oil and gas properties	($860,604)	($786,976)	($735,711)	($516,004)	($340,784)
Proceeds from sales of oil and gas properties, net	12,576	238,470	341,597	167,265	54,217
Proceeds from borrowing and issuances (repayments of debt), net (1)	301,500	(69,325)	244,772	126,401	(7,021)
	—	189,686	—	—	188,534

Proceeds from common stock offerings, net of offering costs					
Balance Sheets from Continuing Operations Data:					
Working deficit	($141,278)	($32,138)	($43,432)	($150,559)	($58,672)
Total property and equipment, net	2,629,253	1,794,215	1,487,674	1,240,917	960,393
Total assets	2,981,476	2,110,760	1,749,488	1,445,075	1,121,470
Long-term debt	1,351,346	900,247	967,808	711,486	558,254
Total shareholders' equity	1,103,441	841,604	585,016	509,855	456,636

(1) Repayments include amounts refinanced.

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

General Overview

Our crude oil production increased as a percentage of total production from 3% for the year ended December 31, 2010 to 58% for the year ended December 31, 2014. Total production for the year ended December 31, 2014 was a record 12.0 MMBoe, or 32,816 Boe/d, as compared to10.0 MMBoe, or 27,395 Boe/d for the year ended December 31, 2013. In 2014, we recognized record total revenues of $710.2 million, as compared to $520.2 million in 2013. Average realized oil and natural gas prices for 2014 were $88.40 per Bbl and $3.00 per Mcf, respectively.

Operations. See the table below for details of our operated drilling and completion activity in our primary areas of activity:

	For the Year Ended December 31, 2014				As of December 31, 2014				
	Drilled		Wells Brought on Production		Waiting on Completion		Producing		Rig Count
Region	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
Eagle Ford	69	58.0	73	58.7	25	22.5	193	170.9	3
Niobrara	32	13.0	38	15.1	7	3.7	112	47.7	1
Marcellus	3	1.2	19	5.1	11	4.3	82	26.3	—
Utica	3	2.2	2	1.4	2	1.7	1	0.9	1
Other	1	1.0	1	1.0	—	—	—	—	—
Total	108	75.4	133	81.3	45	32.2	388	245.8	5

At December 31, 2014, our estimated net proved oil and natural gas reserves were 151.1 MMBoe, an increase of 49.6 MMBoe from December 31, 2013. During 2014, net proved crude oil reserves increased by 38.7 MMBbls, net proved NGL reserves increased by 5.4 MMBbls and net proved natural gas reserves increased by 33.1 Bcf. Our reserves increased as a result of our ongoing drilling program as well as the acquisition of oil and gas properties in the Eagle Ford Shale Acquisition.

Production for the year ended December 31, 2014 increased 20% as compared to the year ended December 31, 2013 primarily driven by increased crude oil production in Eagle Ford, which attributed 64% to the total production for the year. In 2014, our net Eagle Ford production averaged 21,131 Bbls/d of crude oil as compared to 12,628 Bbls/d in 2013.

Acquisition. In October 2014, we completed the Eagle Ford Shale Acquisition for an agreed upon purchase price of $250.0 million, subject to post-closing and working capital adjustments. We paid EFM a total of $241.8 million, of which we paid approximately $93.0 million at closing, which represented $100.0 million of the agreed upon purchase price less working capital adjustments of $7.0 million, and $148.8 million on February 13, 2015, which represented the deferred purchase payment of the remaining $150.0 million of the agreed upon purchase price, less working capital adjustments of $1.2 million.

Financing Activities and Capital Structure. We have a senior secured revolving credit facility with a syndicate of banks that, as of December 31, 2014, had a borrowing base of $800.0 million, of which $685.0 million has been committed by the lenders with no borrowings and $0.6 million in letters of credit outstanding. In October 2014, we completed a private placement of $300.0 million aggregate principal amount of our 7.50% Senior Notes due 2020. We used the net proceeds of this offering to fund the Eagle Ford Shale Acquisition, repay amounts outstanding under our revolving credit facility and for general corporate purposes.

Our initial 2015 drilling and completion capital expenditure plan is $450.0 million to $470.0 million, a decrease of approximately 36% compared to actual 2014 drilling and completion capital expenditures (exclusive of the Eagle Ford Shale Acquisition). Our 2015 leasehold and seismic capital expenditure plan is $35.0 million, a decrease of 76% compared to actual 2014 leasehold and seismic capital expenditures (exclusive of the Eagle Ford Shale Acquisition). We expect to allocate the majority of our 2015 drilling and completion capital expenditure plan to the continued development of our properties in the Eagle Ford.

Results of Operations

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the years ended December 31, 2014 and 2013:

	Year Ended December 31,		2014 Period Compared to 2013 Period	
	2014	2013	Increase(Decrease)	% Increase(Decrease)
Total production volumes -				
Crude oil (MBbls)	6,906	4,231	2,675	63 %
NGLs (MBbls)	926	531	395	74 %
Natural gas (MMcf)	24,877	31,422	(6,545)	(21 %)
Total Natural gas and NGLs (MMcfe)	30,433	34,608	(4,175)	(12 %)
Total barrels of oil equivalent (MBoe)	11,978	9,999	1,979	20 %
Daily production volumes by product -				
Crude oil (Bbls/d)	18,921	11,592	7,329	63 %
NGLs (Bbls/d)	2,537	1,455	1,082	74 %
Natural gas (Mcf/d)	68,156	86,088	(17,932)	(21 %)
Total Natural gas and NGLs (Mcfe/d)	83,378	94,816	(11,438)	(12 %)
Total barrels of oil equivalent (Boe/d)	32,816	27,395	5,421	20 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	21,131	12,628	8,503	67 %
Niobrara	2,585	1,724	861	50 %
Barnett	—	6,625	(6,625)	(100 %)
Marcellus	8,354	6,139	2,215	36 %
Utica and other	746	279	467	167 %
Total barrels of oil equivalent (Boe/d)	32,816	27,395	5,421	20 %
Average realized prices -				
Crude oil ($ per Bbl)	$88.40	$99.58	($11.18)	(11 %)
NGLs ($ per Bbl)	27.05	29.25	(2.20)	(8 %)
Natural gas ($ per Mcf)	3.00	2.65	0.35	13 %
Total Natural gas and NGLs ($ per Mcfe)	$3.28	$2.86	$0.42	15 %
Total average realized price ($ per Boe)	$59.29	$52.02	$7.27	14 %
Revenues (In thousands) -				
Crude oil	$610,483	$421,311	$189,172	45 %
NGLs	25,050	15,530	9,520	61 %
Natural gas	74,654	83,341	(8,687)	(10 %)
Total revenues	$710,187	$520,182	$190,005	37 %

Revenues for 2014 increased 37% to $710.2 million compared to $520.2 million in 2013 primarily due to the significant increase in oil production, partially offset by the significant decrease in oil prices. Production volumes in 2014 and 2013 were 12.0 MMBoe and 10.0 MMBoe, respectively. The increase in production from 2013 to 2014 was primarily due to increased production from new wells in Eagle Ford, Niobrara, and Marcellus, partially offset by normal production declines and the sale of our remaining Barnett oil and gas properties to EnerVest. See "Item 1. Business—Natural Gas Plays—Barnett" for additional information. Average realized oil prices decreased 11% to $88.40 per Bbl in 2014 from $99.58 per Bbl in 2013. Average realized natural gas prices increased 13% to $3.00 per Mcf in 2014 from $2.65 per Mcf in 2013. Average realized NGL prices decreased 8% to $27.05 per Bbl in 2014 from $29.25 per Bbl in 2013.

Lease operating expenses for 2014 increased to $74.2 million ($6.19 per Boe) from $46.8 million ($4.68 per Boe) in 2013. The increase in lease operating expense is primarily due to increased operating costs associated with increased production from new wells in the Eagle Ford, partially offset by the sale of our Barnett properties to EnerVest. The increase in lease operating expense per Boe is primarily due to the sale of lower operating cost per Boe gas properties in the Barnett as well as increased production from higher operating cost per Boe oil properties in the Eagle Ford.

Production taxes increased to $29.5 million (or 4.2% of revenues) in 2014 from $19.8 million (or 3.8% of revenues) in 2013 as a result of increased production, primarily in the Eagle Ford, partially offset by normal production declines. The increase in production taxes as a percentage of revenues was primarily due to increased oil production, which has a higher effective production tax rate as compared to natural gas production.

Ad valorem taxes decreased to $8.5 million ($0.71 per Boe) in 2014 from $8.7 million ($0.87 per Boe) in 2013. The decrease in ad valorem taxes is due primarily to lower actual ad valorem taxes than previously estimated for the year ended December 31, 2013 and the sale of our Barnett properties to EnerVest, partially offset by an increase in ad valorem taxes for new wells drilled in Eagle Ford in 2013.

Depreciation, depletion and amortization ("DD&A") expense for 2014 increased $103.1 million to $317.4 million ($26.50 per Boe) from the DD&A expense for 2013 of $214.3 million ($21.43 per Boe). The increase in DD&A is attributable to both the increase in production and an increase in the DD&A rate per Boe. The increase in the DD&A rate per Boe is largely due to the impact of the significant decrease in natural gas reserves in the Barnett as a result of the sale to EnerVest as well as the increase in crude oil reserves, primarily in the Eagle Ford, which have a higher finding cost per Boe than our natural gas reserves. The components of our DD&A expense were as follows:

	Year Ended December 31,	
	2014	2013
	(In thousands)	
DD&A of proved oil and gas properties	$313,799	$211,157
Depreciation of other property and equipment	1,722	1,693
Amortization of other assets	1,152	970
Accretion of asset retirement obligations	710	471
Total DD&A	$317,383	$214,291

General and administrative expense decreased to $77.0 million for 2014 from $77.5 million for 2013. The decrease was primarily due to decreases in stock-based compensation costs related to the decrease in the fair value of stock appreciation rights, partially offset by higher compensation costs resulting from an increase in personnel for 2014 compared to 2013.

The gain on derivatives, net for 2014 amounted to $201.9 million primarily due to new hedge positions in 2014 and the significant downward shift in the futures curve of forecasted commodity prices for crude oil and natural gas during the fourth quarter of 2014. The loss on derivatives, net for 2013 amounted to $18.4 million primarily due to the upward shift in the futures curve of forecasted commodity prices for crude oil and natural gas from January 1, 2013 (or the subsequent date prior year contracts were entered into) to December 31, 2013.

Interest expense, net for 2014 was $53.2 million as compared to $54.7 million for 2013. The decrease was primarily due to the repurchase of the 4.375% convertible senior notes in June 2013 as well as an increase in the amount of interest that was capitalized due to a higher average balance of unproved properties, partially offset by an increase in interest expense attributable to interest on the $300.0 million aggregate principal amount of our 7.50% Senior Notes that were issued in October 2014 as well as an increase in borrowings under our revolving credit facility.

The effective income tax rate was 36.5% for 2014 and 37.1% for 2013. The rates are higher than the U.S. federal statutory rate of 35% primarily due to the impact of state income taxes.

Income from discontinued operations, net of income taxes for 2014 amounted to $4.1 million. The income from discontinued operations, net of income taxes is related to the sale of Carrizo UK. The income was primarily due to the fluctuation in fair value of the accrual for estimated future obligations as a result of the significant downward shift in the futures curve of forecasted commodity prices for Brent crude oil during the fourth quarter of 2014.

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the years ended December 31, 2013 and 2012:

	Year Ended December 31,		2013 Period Compared to 2012 Period	
	2013	2012	Increase(Decrease)	% Increase(Decrease)
Total production volumes -				
Crude oil (MBbls)	4,231	2,862	1,369	48 %
NGLs (MBbls)	531	305	226	74 %
Natural gas (MMcf)	31,422	37,612	(6,190)	(16 %)
Total Natural gas and NGLs (MMcfe)	34,608	39,442	(4,834)	(12 %)
Total barrels of oil equivalent (MBoe)	9,999	9,436	563	6 %
Daily production volumes by product -				
Crude oil (Bbls/d)	11,592	7,820	3,772	48 %
NGLs (Bbls/d)	1,455	833	622	75 %
Natural gas (Mcf/d)	86,088	102,765	(16,677)	(16 %)
Total Natural gas and NGLs (Mcfe/d)	94,816	107,765	(12,949)	(12 %)
Total barrels of oil equivalent (Boe/d)	27,395	25,781	1,614	6 %
Daily production volumes by region (Boe/d) -				
Eagle Ford	12,628	7,950	4,678	59 %
Niobrara	1,724	1,259	465	37 %
Barnett	6,625	11,614	(4,989)	(43 %)
Marcellus	6,139	3,608	2,531	70 %
Utica and other	279	1,350	(1,071)	(79 %)
Total barrels of oil equivalent (Boe/d)	27,395	25,781	1,614	6 %
Average realized prices -				
Crude oil ($ per Bbl)	$99.58	$99.97	($0.39)	— %
NGLs ($ per Bbl)	29.25	34.86	(5.61)	(16 %)
Natural gas ($ per Mcf)	2.65	1.90	0.75	39 %
Total Natural gas and NGLs ($ per Mcfe)	$2.86	$2.08	$0.78	38 %
Total average realized price ($ per Boe)	$52.02	$39.02	$13.00	33 %
Revenues (In thousands) -				
Crude oil	$421,311	$286,119	$135,192	47 %
NGLs	15,530	10,631	4,899	46 %
Natural gas	83,341	71,430	11,911	17 %
Total revenues	$520,182	$368,180	$152,002	41 %

Revenues for 2013 increased 41% to $520.2 million compared to $368.2 million in 2012. Production volumes in 2013 were 10.0 MMBoe, an increase of 6%, compared to production of 9.4 MMBoe in 2012. The increase in production was primarily due to increased production from new wells, partially offset by normal production decline and the Atlas and EnerVest sales. See “Item 1. Business—Natural Gas Plays—Barnett” for additional information. Average realized oil prices remained relatively flat at $99.58 per Bbl in 2013 compared to $99.97 per Bbl in 2012. Average realized natural gas prices increased 39% to $2.65 per Mcf in 2013 from $1.90 per Mcf in 2012. Average realized NGL prices decreased 16% to $29.25 per Bbl in 2013 from $34.86 per Bbl in 2012.

Lease operating expenses for 2013 increased to $46.8 million ($4.68 per Boe) from $31.5 million ($3.34 per Boe) in 2012. Lease operating expenses increased primarily due to new wells brought on production, partially offset by the Atlas and EnerVest sales. The increase in lease operating expense per Boe is primarily due to the higher operating cost per Boe associated with the increased oil production.

Production taxes increased to $19.8 million (or 3.8% of revenues) in 2013 from $13.5 million (or 3.7% of revenues) in 2012 as a result of increased oil production in 2013. The increase in production taxes as a percentage of revenues was primarily due to increased oil production, which has a higher effective production tax rate as compared to our natural gas production.

Ad valorem taxes decreased to $8.7 million ($0.87 per Boe) in 2013 from $9.8 million ($1.04 per Boe) in 2012. The decrease in ad valorem taxes is due primarily to the sale of our Barnett properties to Atlas and EnerVest and the Commonwealth of Pennsylvania's February 2012 enactment of an "impact fee" on the drilling of unconventional natural gas wells. Because of the retroactive nature of the impact fee, approximately $1.0 million of ad valorem taxes recognized during the first half of 2012 was attributable to wells drilled prior to 2012.

DD&A expense for 2013 increased to $214.3 million ($21.43 per Boe) from $166.0 million ($17.59 per Boe) in 2012. The increase in DD&A is attributable to both the increase in production and an increase in the DD&A rate per Boe. The increase in the DD&A rate per Boe is largely due to the impact of the significant decrease in natural gas reserves in the Barnett as a result of the EnerVest sale as well as the increase in crude oil reserves, primarily in the Eagle Ford, which have a higher finding cost per Boe than our natural gas reserves. The components of our DD&A expense were as follows:

	Year Ended December 31,	
	2013	2012
	(In thousands)	
DD&A of proved oil and gas properties	$211,157	$163,542
Depreciation of other property and equipment	1,693	1,543
Amortization of other assets	970	536
Accretion of asset retirement obligations	471	372
Total DD&A	$214,291	$165,993

General and administrative expense for 2013 increased to $77.5 million from $48.7 million in 2012. The increase was primarily due to increased stock-based compensation costs related to an increase in the fair value of stock appreciation rights due to an increase in stock price during 2013 as compared 2012, and an increase in compensation costs generally, largely due to an increase in personnel in 2013 as compared to 2012.

Included in income from continuing operations in 2013 is a loss on the sale of oil and gas properties of $45.4 million due to the sale of our remaining oil and gas properties in the Barnett to EnerVest during the fourth quarter of 2013. Because the sale resulted in a significant alteration of the relationship between capitalized costs and proved reserves of oil and gas attributable to our U.S. cost center, the sale was recognized as a component of income from continuing operations rather than recording the proceeds as a reduction of proved oil and gas properties.

The loss on derivatives, net for 2013 amounted to $18.4 million primarily due to an upward shift in the futures curve of forecasted commodity prices for crude oil and natural gas from January 1, 2013 (or the subsequent date prior year contracts were entered into) to December 31, 2013. The gain on derivatives, net for 2012 amounted to $31.4 million primarily due to a downward shift in the futures curve of forecasted commodity prices for crude oil and natural gas from January 1, 2012 (or the subsequent date prior year contracts were entered into) to December 31, 2012.

Interest expense, net for 2013 was $54.7 million as compared to $48.2 million for 2012. The increase in interest expense was primarily due to interest on the $300.0 million aggregate principal amount of our 7.50% Senior Notes that were issued in the third quarter of 2012 partially offset by a decrease in interest expense attributable to reduced borrowings under our revolving credit facility and the repurchase of the 4.375% convertible senior notes during the second quarter of 2013.

Our effective income tax rate was 37.1% for 2013 and 37.7% for 2012 which is higher than the statutory rate due primarily to the effect of state income taxes.

Included in net income of $43.7 million for 2013 was $23.7 million, net of income taxes, related to a gain on the sale of Carrizo UK, which is included in income from discontinued operations, net of income taxes in the accompanying consolidated statements of income.

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Liquidity and Capital Resources

2015 Capital Expenditure Plan and Funding Strategy. Our initial 2015 drilling and completion capital expenditure plan is $450.0 million to $470.0 million (at the midpoint, approximately $377.0 million for the Eagle Ford Shale, $30.0 million for the Utica Shale, $37.0 million for the Niobrara Formation, $7.0 million for the Marcellus Shale, and $9.0 million in other areas) and $35.0 million for leasehold and seismic. We currently intend to finance our 2015 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 capital expenditure plan and the expenditures included above exclude capitalized general and administrative expense, capitalized interest and capitalized asset retirement obligations.

Sources and Uses of Cash. Our primary use of cash is capital expenditures related to our drilling and completion programs and, to a lesser extent, our leasehold and seismic data acquisition programs. For the year ended December 31, 2014, capital expenditures and acquisitions of oil and gas properties, net of proceeds from sales of oil and gas properties exceeded our net cash provided by operations for continuing operations. During 2014, we funded our capital expenditures with cash provided by operations, cash on hand, net proceeds from the offering of our 7.50% Senior Notes that were issued in October 2014 and borrowings under our revolving credit facility. In October 2014, we completed the acquisition of additional interests in oil and gas properties from EFM for approximately $241.8 million, net of working capital adjustments. We paid $93.0 million at closing and $148.8 million on February 13, 2015 with borrowings under our revolving credit facility. Potential sources of future liquidity include the following:

- Cash provided by operations. Cash flows from operations are highly dependent on commodity prices. As such, we hedge a portion of our forecasted production to mitigate the risk of a decline in oil and gas prices.
- Borrowings under our revolving credit facility. At February 20, 2015, we had $210.0 million of borrowings outstanding and $0.6 million in letters of credit outstanding under our revolving credit facility, 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.
- 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.
- Securities offerings. In October 2014, we issued $300.0 million aggregate principal amount of 7.50% Senior Notes due 2020 in a private placement for net proceeds of $299.8 million. As situations or conditions arise, we may choose to issue debt, equity or other instruments 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.
- 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.
- Other sources. We may consider sale/leaseback transactions of certain capital assets, such as our remaining pipelines and compressors, which are not part of our core oil and gas exploration and production business.

Overview of Cash Flow Activities. Net cash provided by operating activities from continuing operations was $502.3 million, $367.5 million and $253.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. The increase from 2013 to 2014 was primarily due to increased crude oil revenues partially offset by increased operating expenses and net cash from derivative settlements. The increase from 2012 to 2013 was primarily due to increased crude oil revenues partially offset by increased operating expenses and a decrease in the net cash from derivative settlements.

Net cash used in investing activities from continuing operations was $940.7 million, $509.9 million and $465.2 million for the years ended December 31, 2014, 2013 and 2012, respectively. The increase from 2013 to 2014 related primarily to increased capital expenditures in the Eagle Ford, Niobrara and Utica and the acquisition of additional interests in oil and gas properties associated with the Eagle Ford Shale Acquisition as well as lower proceeds from sales of oil and gas properties. The increase from 2012 to 2013 related primarily to increased capital expenditures in the Eagle Ford, Niobrara and Marcellus as well as lower proceeds received from sales of oil and gas properties, offset by the utilization of advances received for joint operations.

Net cash provided by financing activities from continuing operations for the years ended December 31, 2014, 2013 and 2012 was $300.3 million, $120.3 million and $237.8 million, respectively. The increase from 2013 to 2014 was primarily due to proceeds of $299.8 million related to the issuance of the $300.0 million aggregate principal amount of 7.50% Senior Notes received in October 2014 compared to proceeds of $189.7 million related to the issuance of common stock in November 2013 less the $69.3 million repurchase of convertible senior notes in June 2013. The decrease from 2012 to 2013 was primarily due to proceeds of

$294.2 million from the issuance of $300.0 million aggregate principal amount of 7.50% Senior Notes received in September 2012 as compared to proceeds of $189.7 million related to the issuance of common stock in November 2013 less the $69.3 million repurchase of convertible senior notes in June 2013.

Liquidity/Cash Flow Outlook

Economic downturns may adversely affect our ability to access capital markets in the future. We currently believe that cash flows from operations and borrowings under our revolving credit facility will be sufficient to fund our immediate cash flow requirements. Cash flows from operations are primarily driven by production and commodity prices. Crude oil prices have declined significantly since July 2014. 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 program, we hedge a portion of our forecasted production and, as of December 31, 2014, our hedge positions for 2015 were comprised of 30,000 MMBtu/d of natural gas and 12,070 Bbls/d of crude oil. On February 11, 2015, we entered into derivative transactions offsetting our existing crude oil derivative positions covering the periods from March 2015 through December 2016, which locked in $166.4 million of cash flows which will be received in 2015 and 2016 as the derivative contracts settle. Additionally, on February 13, 2015, we entered into costless collars for the periods from March 2015 through December 2016 which will continue to provide us with solid downside protection on 12,200 Bbls/d in 2015 and 4,000 Bbls/d in 2016 of crude oil at prices below the floor of $50.00 per Bbl yet allow us to benefit from an increase in crude oil prices up to the ceiling of $66.46 per Bbl in 2015 and $76.50 per Bbl in 2016. See "Note 16. Subsequent Events (Unaudited)" for additional information regarding our derivative instruments.

As of February 20, 2015, we had $210.0 million of borrowings outstanding under our revolving credit facility and had issued $0.6 million in letters of credit, which reduce the amounts available under our revolving credit facility. The amounts 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. The borrowing base under our revolving credit facility is affected by our lenders' assumptions with respect to future oil and gas prices. Our borrowing base may decrease if our lenders reduce their expectations with respect to future oil and gas prices from those assumptions used to determine our existing borrowing base. Crude oil prices have declined significantly since our Fall 2014 borrowing base redetermination. The next borrowing base redetermination is expected to occur in the Spring of 2015 and as a result of that redetermination, based on the currently available bank pricing assumptions, drilling and completion plans and reserves assumptions, we expect our borrowing base to decrease to an amount that approximates our $685.0 million commitment amount. Looking forward to the Fall 2015 borrowing base redetermination, based on currently available bank pricing assumptions, drilling and completion plans and reserve assumptions, we currently expect the redetermination to result in a borrowing base of approximately $725.0 million.

If cash flows from operations and borrowings under our revolving credit facility and the other sources of cash described under "—Sources and Uses of Cash" are insufficient to fund our 2015 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 our planned 2015 capital expenditure plan, thereby adversely affecting the recoverability and ultimate value of our oil and gas properties. Subject in each case to then existing market conditions and to our then 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, 2014 (in thousands):

	2015	2016	2017	2018	2019	2020 and Thereafter	Total
Debt (1)	$150,000	$—	$—	$600,000	$—	$604,425	$1,354,425
Interest on debt (2)	96,944	96,944	96,944	96,944	45,194	46,627	479,597
Operating leases	3,795	3,773	3,902	3,975	4,103	10,139	29,687
Drilling and completion services (3)	44,155	27,923	20,057	4,702	—	—	96,837
Pipeline volume commitments	7,485	4,324	2,465	2,464	2,390	6,795	25,923
Asset retirement obligations and other (4)	4,730	5,369	2,649	385	23	12,156	25,312
Total Contractual Obligations	$307,109	$138,333	$126,017	$708,470	$51,710	$680,142	$2,011,781

(1) Debt consists of the principal amounts of the 8.625% Senior Notes due 2018, the 7.50% Senior Notes due 2020, other long-term debt due 2028 and the deferred purchase payment due EFM on or before February 16, 2015.

(2) Interest on debt includes cash payments for interest on the 8.625% Senior Notes due 2018, the 7.50% Senior Notes due 2020 and other long-term debt due 2028. There were no borrowings outstanding under our revolving credit facility as of December 31, 2014, therefore no interest was computed for our revolving credit facility as it relates to the table above.

(3) Drilling and completion services 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.

(4) Asset retirement obligations and other are based on estimates and assumptions that affect the reported amounts as of December 31, 2014. Certain of such estimates and assumptions are inherently unpredictable and will differ from actuals results. See "Note 2. Summary of Significant Accounting Policies-Use of Estimates" for further discussion of estimates and assumptions that may affect the reported amounts.

(5) This table does not include deferred income tax liabilities or share-based payments classified as liabilities, as we cannot reasonably determine the timing of such payments.

Off Balance Sheet Arrangements

We currently do not have any off balance sheet arrangements.

Financing Arrangements

8.625% Senior Notes and 7.50% Senior Notes

As of December 31, 2014, we had $600.0 million aggregate principal amount of 8.625% Senior Notes due 2018 issued and outstanding. The 8.625% Senior Notes are guaranteed by all of our existing Material Domestic Subsidiaries (as defined in the credit agreement governing our revolving credit facility).

The 8.625% Senior Notes mature on October 15, 2018, with interest payable semi-annually. Since October 15, 2014, we had the right to redeem all or a portion of our 8.625% Senior Notes at redemption prices decreasing from 104.313% to 100% of the principal amount on October 15, 2017, plus accrued and unpaid interest. Holders of the 8.625% Senior Notes may require us to repurchase some or all of their 8.625% Senior Notes for cash in the event of a Change of Control (as defined in the indenture governing the 8.625% Senior Notes), at 101% of the principal amount plus accrued and unpaid interest. We could seek to refinance the 8.625% Senior Notes in connection with such redemption or a repurchase of notes.

As of December 31, 2014, we had $600.0 million aggregate principal amount of 7.50% Senior Notes due 2020 that were issued and outstanding. The 7.50% Senior Notes are guaranteed by the same subsidiaries that guarantee our 8.625% Senior Notes.

The 7.50% Senior Notes mature on September 15, 2020, with interest payable semi-annually. We may redeem all or a portion of the 7.50% Senior Notes at any time on or after September 15, 2016 at redemption prices decreasing from 103.750% to 100% of the principal amount on September 15, 2018, plus accrued and unpaid interest. In addition, prior to September 15, 2015, we may, at our option, redeem up to 35% of the aggregate principal amount of the 7.50%

Senior Notes with the proceeds of certain equity offerings at a redemption price of 107.50%, of the principal amount, plus accrued and unpaid interest. Prior to September 15, 2016, we may redeem all or part of the 7.50% Senior Notes at 100% of the principal amount thereof, plus accrued and unpaid interest and a make whole premium (as defined in the indenture governing the 7.50% Senior Notes). Holders of the 7.50% Senior Notes may require us to repurchase some or all of their 7.50% Senior Notes for cash in the event of a Change of Control (as defined in the indenture governing the 7.50% Senior Notes), at 101% of the principal amount plus accrued and unpaid interest.

The indentures governing the 8.625% Senior Notes and the 7.50% Senior Notes contain covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: pay distributions on, purchase or redeem our common stock or other capital stock or redeem our 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 our assets; enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us; engage in transactions with affiliates; and create unrestricted subsidiaries.

The indentures governing the 8.625% Senior Notes and the 7.50% Senior Notes are subject to customary events of default, including those relating to failures to comply with the terms of the notes and the indentures, certain failures to file reports with the SEC, certain cross defaults of other indebtedness and mortgages and certain failures to pay final judgments.

Senior Secured Revolving Credit Facility

We have a senior secured revolving credit facility with a syndicate of banks that, as of December 31, 2014, had a borrowing base of $800.0 million, of which $685.0 million has been committed by the lenders with no borrowings and $0.6 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. A portion of the lender commitments under the credit agreement, in an aggregate amount not to exceed $30.0 million, may be used to issue letters of credit for the account of the Company or certain of its subsidiaries.

Our obligations under the credit agreement are guaranteed by our material domestic subsidiaries and are secured by liens on substantially all of our assets, including a mortgage lien on oil and gas properties having at least 80% of the proved reserve value of the oil and gas properties included in the determination of the borrowing base.

Amounts outstanding under the credit agreement bear interest at our 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. We also incur commitment fees as set forth in the table below on the unused portion of lender commitments, and which are included as a component of interest expense.

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%	0.50%	1.50%	0.375%
Greater than or equal to 25% but less than 50%	0.75%	1.75%	0.375%
Greater than or equal to 50% but less than 75%	1.00%	2.00%	0.500%
Greater than or equal to 75% but less than 90%	1.25%	2.25%	0.500%
Greater than or equal to 90%	1.50%	2.50%	0.500%

We are subject to certain covenants under the terms of the credit agreement, which include the maintenance of the following financial covenants determined as of the last day of each quarter: (1) a ratio of Total Debt to EBITDA (as defined in the credit agreement) of not more than 4.00 to 1.00; and (2) a Current Ratio (as defined in the credit agreement) of not less than 1.00 to 1.00. As defined in the credit agreement, Total Debt is net of cash and cash equivalents, EBITDA is for the last four quarters after giving pro forma effect to certain material acquisitions and dispositions of oil and gas properties, and the Current Ratio includes an add back of the unused portion of lender commitments. As of December 31, 2014, the ratio of Total Debt to EBITDA was 2.33 to 1.00 and the Current Ratio was 2.35 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 amounts outstanding under the credit agreement are dependent on the timing of cash flows from operations, capital expenditures, acquisitions and dispositions of oil and gas properties and securities offerings.

Our revolving credit facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our 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).

Deferred Purchase Payment

On October 24, 2014, we agreed to pay EFM, no later than February 16, 2015, $150.0 million for the remaining portion of the agreed upon purchase price of $250.0 million, less working capital adjustments, associated with the Eagle Ford Shale Acquisition. We have the intent and ability to refinance the deferred purchase payment with available capacity under our revolving credit facility, and accordingly, the deferred purchase payment has been classified as long-term debt in the consolidated balance sheets as of December 31, 2014. The deferred purchase payment was paid on February 13, 2015 with borrowings under the revolving credit facility. See “Note 4. Eagle Ford Shale Acquisition” for further discussion.

Huntington Field Development Project Credit Facility

On January 28, 2011, we and Carrizo UK, as borrower, entered into the Huntington Facility. The Huntington Facility was secured by substantially all of Carrizo UK’s assets and was limited recourse to us. The Huntington Facility provided financing for a substantial portion of Carrizo UK’s share of costs associated with the Huntington Field development project in the U.K. North Sea.

The sale of Carrizo UK, and all of its interest in the Huntington Field discovery, closed on February 22, 2013. The Huntington facility that was secured by substantially all of Carrizo UK’s assets with limited recourse to us was repaid by Iona Energy in connection with the close of the sales transaction.

Securities Offerings in 2014, 2013 and 2012

In October 2014, we issued in a private placement $300.0 million aggregate principal amount of 7.50% Senior Notes due 2020. We used the net proceeds of approximately $299.8 million, net of offering costs, to fund the Eagle Ford Shale Acquisition, repay amounts outstanding under our revolving credit facility and for general corporate purposes.

In February 2015, we completed an exchange offer registered under the Securities Act of 1933, as amended, whereby new 7.50% Senior Notes registered with the SEC were exchanged for such privately placed 7.50% Senior Notes. The privately placed 7.50% Senior Notes have substantially identical terms, other than with respect to certain transfer restrictions and registration rights, as the exchanged 7.50% Senior Notes and our 7.50% Senior Notes that were issued on September 10, 2012, as described below. The new 7.50% Senior Notes registered with the SEC were issued as “additional notes” under the indenture governing our 7.50% Senior Notes that were issued on September 10, 2012 and will be treated as a single series of debt securities with such 7.50% Senior Notes.

In November 2013, we sold 4.5 million shares of our common stock in an underwritten public offering at a price to the underwriter of $42.24 per share. We used the net proceeds of approximately $189.7 million, net of offering costs, to fund a portion of our increased capital expenditure plan and for other general corporate purposes.

In September 2012, we issued in a public offering $300.0 million aggregate principal amount of 7.50% Senior Notes. We used the net proceeds of approximately $294.2 million after deducting the underwriters’ discount and our estimated expenses to repay borrowings outstanding under our revolving credit facility. Holders of all $600.0 million aggregate principal amount of 7.50% Senior Notes will vote as one series under the indenture governing the original 7.50% Senior Notes.

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 July 2014 and began to adversely affect our results of operations in the latter part of 2014. If crude oil prices continue to weaken or do not rebound, 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 U.S. generally accepted accounting principles 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 of proved oil and gas property costs, the present value of 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, drilling requirements and royalty obligations. 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 impairments of unevaluated leasehold costs, fair values of derivative assets and liabilities, stock-based compensation expense, collectability of receivables, and in evaluating disputed claims, interpreting contractual arrangements (including royalty obligations and notional interest calculations) 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, counterparty creditworthiness, interest rates and the market value and volatility of the Company's common stock.

Discontinued Operations

On February 22, 2013, we closed on the sale of Carrizo UK, a wholly owned subsidiary of the Company, and all of its interest in the Huntington Field discovery, including a 15% non-operated working interest and certain overriding royalty interests, to a subsidiary of Iona Energy for an agreed-upon price of $184.0 million, including the assumption and repayment by Iona Energy of the $55.0 million of borrowings outstanding under Carrizo UK's senior secured multicurrency credit facility as of the closing date. The liabilities, results of operations and cash flows associated with Carrizo UK have been classified as discontinued operations in our consolidated financial statements. Unless otherwise indicated, the information included relates to our continuing operations. Information related to discontinued operations is included in "Note 3. Discontinued Operations," "Note 14. Condensed Consolidating Financial Information" and "Note 17. Supplemental Disclosures about Oil and Gas Producing Activities (Unaudited)" of the Notes to our Consolidated Financial Statements.

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 and totaled $18.8 million, $15.0 million and $11.8 million for the years ended December 31, 2014, 2013 and 2012, 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 $26.20, $21.38 and $17.55 for the years ended December 31, 2014, 2013 and 2012, 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 added to the oil and gas property costs subject to amortization. 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. We expect to complete the evaluation of the majority of our unevaluated leaseholds within the next five years and exploratory wells in progress within the next year. Individually insignificant unevaluated leaseholds are grouped by major area and added to the oil and gas property costs subject to amortization based on the average primary lease term of the properties. We capitalized interest costs associated with our unproved properties totaling $34.5 million, $29.9 million and $24.8 million for the years ended December 31, 2014, 2013 and 2012, respectively. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unproved properties using a weighted-average interest rate based on outstanding borrowings.

Proceeds from the sale of proved and unproved oil and gas properties are recognized as a reduction of capitalized 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 2014, we did not have any sales of oil and gas properties that significantly altered such relationship. On February 22, 2013, we closed the sale of Carrizo UK, which included all of our proved reserves in our U.K. cost center. As a result, in the first quarter of 2013, we recognized a $37.3 million pre-tax gain in “Net income from discontinued operations, net of income taxes” in the consolidated statements of income. Further, on October 31, 2013, we closed the sale of our remaining oil and gas properties in the Barnett Shale. The proved reserves attributable to the Barnett Shale sale represented 40% of our proved reserves as of October 31, 2013, which significantly altered the relationship between capitalized costs and proved reserves of oil and gas attributable to our U.S. cost center. As a result, we recognized a pre-tax loss on the sale of $45.4 million in “Loss on sale of oil and gas properties” in the consolidated statements of income in the fourth quarter of 2013. Other than the sales noted above, we have not had any sales that significantly altered the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center through December 31, 2014.

Capitalized costs, less accumulated amortization and 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.

If the net capitalized costs exceed the cost center ceiling, the excess is recognized as an impairment of oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices in the future increase the cost center ceiling applicable to the subsequent period.

The table below presents results of the full cost ceiling test as of December 31, 2014, along with various pricing scenarios to demonstrate the sensitivity of our cost center ceiling to changes in 12 month average benchmark oil and gas prices underlying our average realized prices. Prices do not include the impact of crude oil and natural gas derivative instruments. This sensitivity analysis is as of December 31, 2014 and, accordingly, does not consider drilling results, production and prices subsequent to December 31, 2014 that may require revisions to our proved reserve estimates. See also Part I, “Item 1A. Risk Factors—We may record impairments of oil and gas properties that would reduce our shareholders’ equity.”

	12 Month Average Realized Prices		Excess of cost center ceiling over net capitalized costs	Increase/(Decrease) in excess of cost center ceiling over net capitalized costs
Full Cost Pool Scenarios	Crude Oil ($/Bbl)	Natural Gas ($/Mcf)	(In millions)	(In millions)
December 31, 2014 Actual	$92.24	$3.24	$747	
Oil and Gas Price Sensitivity				
Oil and Gas +10%	$101.72	$3.68	$1,103	$356
Oil and Gas -10%	$82.74	$2.80	$391	($356)
Oil Price Sensitivity				
Oil +10%	$101.72	$3.24	$1,073	$326
Oil -10%	$82.74	$3.24	$421	($326)
Gas Price Sensitivity				
Gas +10%	$92.24	$3.68	$778	$31
Gas -10%	$92.24	$2.80	$716	($31)

Oil and Gas Reserve Estimates

The proved oil and gas reserve estimates as of December 31, 2014 included in this document have been prepared by Ryder Scott Company, L.P., 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 oil and gas prices and the discount rate.

Proved oil and gas reserve estimates prepared by others may be substantially higher or lower than our estimates. Significant assumptions used by the independent third party reserve engineers are assessed by our internal reserve team. All reserve reports prepared by the independent third party reserve engineers 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.

You should not assume 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. A 10% increase or decrease in our estimates of total proved reserves at December 31, 2014, would have decreased or increased our DD&A expense of proved oil and gas properties by approximately 8.9% or 10.8%, respectively, for the fourth quarter of 2014.

Derivative Instruments

We use commodity derivative instruments, primarily fixed price swaps and costless collars, to reduce our exposure to commodity price volatility for a substantial, but varying, portion of our forecasted oil and gas production up to 36 months 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. Although the derivative instruments provide an economic hedge of our exposure to commodity price volatility, because we 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 income 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 reviews derivative instruments, including volumes, types of instruments and counterparties, on a quarterly basis. 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 routinely assess the realizability of our deferred tax assets by taxing jurisdiction and consider our estimate of future taxable income based on production of proved reserves at estimated future pricing in making such assessments. If we conclude that it is more likely than not that some portion or all of the benefit from deferred tax assets will not be realized, the deferred tax assets are reduced by a valuation allowance. 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

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry specific guidance in Subtopic 932-605, Extractive Activities- Oil and Gas- Revenue Recognition. This ASU requires entities to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods and services. This ASU is effective for annual and interim periods beginning in 2017, and is required to be adopted either retrospectively or as a cumulative-effect adjustment as of the date of adoption, with no early adoption permitted. We are currently evaluating the impact of the adoption of this ASU on our consolidated financial statements.

Volatility of Oil and 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 oil and gas, which are affected by changes in market demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. In 2014, average realized oil prices decreased 11% to $88.40 per Bbl from $99.58 per Bbl in 2013. Average natural gas prices increased 13% to $3.00 per Mcf in 2014 from $2.65 per Mcf in 2013.

We review the carrying value of our oil and gas properties on a quarterly basis using the full cost method of accounting. See "—Summary of Critical Accounting Policies—Oil and Gas Properties." See also Part I, "Item 1A. Risk Factors—We may record impairments of oil and gas properties that would reduce our shareholders' equity."

We use commodity derivative instruments, primarily fixed price swaps and costless collars, to reduce our exposure to commodity price volatility for a substantial, but varying, portion of our forecasted oil and gas production up to 36 months and thereby achieve a more predictable level of cash flows to support our drilling and completion capital expenditure program. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. We do not enter into derivative instruments for speculative or trading purposes.

We typically have 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. 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. The fair value of derivative instruments where we are in a net asset position with our counterparties as of December 31, 2014 and 2013 totaled $214.8 million and $9.3 million, respectively, and is summarized by counterparty in the table below:

Counterparty	December 31, 2014		December 31, 2013	
Wells Fargo	37	%	23	%
Societe Generale	26	%	31	%
Credit Suisse	24	%	46	%
Regions	8	%	—	%
Union Bank	4	%	—	%
Royal Bank of Canada	1	%	—	%
Total	100	%	100	%

The counterparties to our derivative instruments are lenders under our credit agreement. Because each of the lenders have investment grade credit ratings, we believe we have minimal credit risk and accordingly do not currently require our counterparties to post collateral to support the net asset positions of our derivative instruments. As such, we are exposed to credit risk to the extent of nonperformance by the counterparties to our derivative instruments. Although we do not currently anticipate such nonperformance, we continue to monitor the financial viability of our counterparties.

For the years ended December 31, 2014, 2013 and 2012, we recorded in the consolidated statements of income a gain on derivatives, net of $201.9 million, a loss on derivatives, net of $18.4 million, and a gain on derivatives, net of $31.4 million, respectively.

The following sets forth a summary of our crude oil derivative positions at average NYMEX prices as of December 31, 2014.

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Weighted Average Short Put Price ($/Bbl)	Weighted Average Put Spread ($/Bbl)
January - December 2015	Fixed Price Swaps	10,370	$92.97			
	Costless Collars	700	$90.00	$100.65		
	Three-way Collars	1,000	$85.00	$105.00	$65.00	$20.00
January - December 2016	Fixed Price Swaps	3,000	$91.09			
	Three-way Collars	667	$85.00	$104.00	$65.00	$20.00

The following sets forth a summary of our natural gas derivative positions at average NYMEX prices as of December 31, 2014.

Period	Type of Contract	Volumes (in MMBtu/d)	Weighted Average Floor Price ($/MMBtu)
January - December 2015	Fixed Price Swaps	30,000	$4.29

On February 11, 2015, we entered into derivative transactions offsetting our existing crude oil derivative positions covering the periods from March 2015 through December 2016. Additionally, on February 13, 2015, we entered into costless collars for the periods from March 2015 through December 2016 which will continue to provide us with solid downside protection on 12,200 Bbls/d in 2015 and 4,000 Bbls/d in 2016 of crude oil at prices below the floor of $50.00 per Bbl yet allow us to benefit from an increase in crude oil prices up to the ceiling of $66.46 per Bbl in 2015 and $76.50 per Bbl in 2016. See “Note 16. Subsequent Events (Unaudited)” for additional information regarding our derivative instruments.

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 and gas production would have an approximate $71.0 million impact on our revenues for the year ended December 31, 2014.

We use various types of derivative instruments, primarily fixed price swaps and costless collars, to manage our exposure to commodity price risk and to provide a level of certainty in our forward cash flows supporting our capital expenditure program. Our current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 36 months. We do not enter into derivative instruments for speculative or trading purposes. For the years ended December 31, 2014, 2013 and 2012, we recorded in the consolidated statements of income a gain on derivative instruments, net of $201.9 million, a loss on derivative instruments, net of $18.4 million, and a gain on derivative instruments, net of $31.4 million, respectively.

Financial Instruments and Debt Maturities

In addition to our derivative instruments, our other financial instruments include 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 borrowings under our revolving credit facility approximate the carrying amounts as of December 31, 2014, and were based upon interest rates currently available to us for borrowings with similar terms. The fair values of our 8.625% Senior Notes, 7.50% Senior Notes, and other long-term debt as of December 31, 2014 were estimated at approximately $597.0 million, $573.0 million, and $4.1 million, respectively, and were based on quoted market prices. As of December 31, 2014, the fair value of the deferred purchase payment due to EFM was $148.6 million based on indirect observable market rates. As of December 31, 2014, scheduled maturities of debt are $150.0 million in 2015, $600.0 million in 2018, $600.0 million in 2020, and $4.4 million in 2028.

Item 8. Financial Statements and Supplementary Data

The financial statements and information required by this Item appears on pages F-1 through F-38 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 Securities and Exchange Commission (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, 2014. In making this evaluation, management used the Internal Control – Integrated Framework (1992) 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, 2014.

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, 2014, 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, 2014 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 “2015 Proxy Statement”) for our 2015 annual meeting of shareholders. The 2015 Proxy Statement will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2015 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

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 2015 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

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

The information required by this item is incorporated herein by reference to the 2015 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the 2015 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2014.

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
†2.1	—	Asset Purchase Agreement dated October 24, 2014 by and between Eagle Ford Minerals, LLC and Carrizo (Eagle Ford) LLC (incorporated herein by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on October 27, 2014 (File No. 000-29187-87)).
†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	—	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)).
†4.5	—	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)).
†4.6	—	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)).
†4.7	—	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)).
†4.8	—	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)).

†4.9	—	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)).
†4.10	—	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)).
†4.11	—	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)).
†4.12	—	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)).
†4.13	—	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)).
†4.14	—	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)).
†4.15	—	Fifteenth Supplemental Indenture dated November 6, 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 November 17, 2011 (File No. 000-29187-87)).
†4.16	—	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)).
4.17	—	Officers' Certificate of the Company dated as of February 23, 2015.
†4.18	—	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)).
†4.19	—	Registration Rights Agreement, dated October 30, 2014, among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Securities, LLC, RBC Capital Markets, LLC and Citigroup Global Markets, Inc., as representatives of the several Initial Purchasers (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 30, 2014 (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	—	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)).
*†10.3	—	Amended and Restated Employment Agreement between the Company and Paul F. Boling (incorporated herein by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on June 9, 2009 (File No. 000-29187-87)).

*†10.4	—	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)).
*†10.5	—	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)).

*†10.6	—	Amended and Restated Employment Agreement between the Company and Gregory E. Evans (incorporated herein by reference to Exhibit 10.5 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 August 11, 2014 by and between Carrizo Oil & Gas, Inc. and Gregory E. Evans.
*†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.
*†10.11	—	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)).
*†10.12	—	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)).
*†10.13	—	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)).
*†10.14	—	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)).
*†10.15	—	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)).
*†10.16	—	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)).
*†10.17	—	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)).
*†10.18	—	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)).
*†10.19	—	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)).
*†10.20	—	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)).
*†10.21	—	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)).
†10.22	—	S Corporation Tax Allocation, Payment and Indemnification Agreement among the Company and Messrs. Loyd, Webster, Johnson, Hamilton and Wojtek (incorporated herein by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).

†10.23	—	S Corporation Tax Allocation, Payment and Indemnification Agreement among Carrizo Production, Inc. and Messrs. Loyd, Webster, Johnson, Hamilton and Wojtek (incorporated herein by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 (Registration No. 333-29187)).

†10.24	—	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)).
†10.25	—	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)).
†10.26	—	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)).
†10.27	—	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 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)).
†10.28	—	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 by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 11, 2013 (File No. 000-29187-87)).
†10.29	—	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 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)).
†10.30	—	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)).
†10.31	—	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)).
†10.32	—	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)).
†10.33	—	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, 2014.

† Incorporated by reference as indicated.
* Management contract or compensatory plan or arrangement.

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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, 2014 and 2013, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Carrizo Oil & Gas, Inc. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 24, 2015

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, 2014, based on criteria established in Internal Control – Integrated Framework (1992) 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 as presented within Item 9A. Controls and Procedures. 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, 2014, based on criteria established in Internal Control – Integrated Framework (1992) issued by the 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, 2014 and 2013, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 24, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 24, 2015

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

	December 31, 2014	2013
Assets		
Current assets		
Cash and cash equivalents	$10,838	$157,439
Accounts receivable, net	92,946	111,195
Derivative assets	171,101	—
Deferred income taxes	—	4,201
Other current assets	3,736	6,926
Total current assets	278,621	279,761
Property and equipment		
Oil and gas properties, full cost method		
Proved properties, net	2,086,727	1,408,484
Unproved properties, not being amortized	535,197	377,437
Other property and equipment, net	7,329	8,294
Total property and equipment, net	2,629,253	1,794,215
Derivative assets	43,684	9,284
Debt issuance costs	25,403	22,899
Other assets	4,515	4,601
Total Assets	$2,981,476	$2,110,760
Liabilities and Shareholders’ Equity		
Current liabilities		
Accounts payable	$106,819	$57,146
Revenues and royalties payable	66,954	79,136
Accrued capital expenditures	106,149	87,031
Accrued interest	21,149	17,430
Advances for joint operations	8,814	19,967
Liabilities of discontinued operations	4,405	10,936
Deferred income taxes	61,258	—
Other current liabilities	48,756	51,189
Total current liabilities	424,304	322,835
Long-term debt	1,351,346	900,247
Liabilities of discontinued operations	8,394	17,336
Deferred income taxes	77,349	16,856
Asset retirement obligations	12,187	6,576
Other liabilities	4,455	5,306
Total liabilities	1,878,035	1,269,156
Commitments and contingencies		
Shareholders’ equity		
Common stock, $0.01 par value, 90,000,000 shares authorized; 46,127,924 issued and outstanding as of December 31, 2014 and 45,468,675 issued and outstanding as of December 31, 2013	461	455
Additional paid-in capital	915,436	879,948
Retained earnings (Accumulated deficit)	187,544	(38,799)
Total shareholders’ equity	1,103,441	841,604

Total Liabilities and Shareholders' Equity	$2,981,476	$2,110,760

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

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

	For the Years Ended December 31,		
	2014	2013	2012
Revenues			
Crude oil	$610,483	$421,311	$286,119
Natural gas liquids	25,050	15,530	10,631
Natural gas	74,654	83,341	71,430
Total revenues	710,187	520,182	368,180
Costs and Expenses			
Lease operating	74,157	46,828	31,471
Production taxes	29,544	19,811	13,542
Ad valorem taxes	8,450	8,701	9,813
Depreciation, depletion and amortization	317,383	214,291	165,993
General and administrative	77,029	77,492	48,708
(Gain) loss on derivatives, net	(201,907)	18,417	(31,371)
Interest expense, net	53,171	54,689	48,158
Loss on sale of oil and gas properties	—	45,377	—
Other (income) expense, net	2,150	(185)	(267)
Total costs and expenses	359,977	485,421	286,047
Income From Continuing Operations Before Income Taxes	350,210	34,761	82,133
Income tax expense	(127,927)	(12,903)	(30,956)
Income From Continuing Operations	$222,283	$21,858	$51,177
Income From Discontinued Operations, Net of Income Taxes	4,060	21,825	4,310
Net Income	$226,343	$43,683	$55,487
Net Income Per Common Share - Basic			
Income from continuing operations	$4.90	$0.54	$1.29
Income from discontinued operations, net of income taxes	0.09	0.53	0.11
Net income	$4.99	$1.07	$1.40
Net Income Per Common Share - Diluted			
Income from continuing operations	$4.81	$0.53	$1.28
Income from discontinued operations, net of income taxes	0.09	0.53	0.11
Net income	$4.90	$1.06	$1.39
Weighted Average Common Shares Outstanding			
Basic	45,372	40,781	39,591
Diluted	46,194	41,355	40,026

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

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

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Shareholders' Equity
	Shares	Amount			
Balance as of January 1, 2012	39,562,676	$395	$647,429	($137,969)	$509,855
Stock options exercised for cash	20,500	1	106	—	107
Stock-based compensation	—	—	17,396	—	17,396
Common stock activity, net of forfeitures	488,052	5	(85)	—	(80)
Other	93,289	1	2,250	—	2,251
Net income	—	—	—	55,487	55,487
Balance as of December 31, 2012	40,164,517	$402	$667,096	($82,482)	$585,016
Stock options exercised for cash	206,501	2	1,251	—	1,253
Stock-based compensation	—	—	19,531	—	19,531
Common stock activity, net of forfeitures	552,831	6	(539)	—	(533)
Sale of common stock, net of offering costs	4,500,000	45	189,641	—	189,686
Other	44,826	—	2,968	—	2,968
Net income	—	—	—	43,683	43,683
Balance as of December 31, 2013	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
Common stock activity, 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

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

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

	For the Years Ended December 31,		
	2014	2013	2012
Cash Flows From Operating Activities			
Net income	$226,343	$43,683	$55,487
Income from discontinued operations, net of income taxes	(4,060)	(21,825)	(4,310)
Adjustments to reconcile income from continuing operations to net cash provided by operating activities from continuing operations			
Depreciation, depletion and amortization	317,383	214,291	165,993
Non-cash (gain) loss on derivatives, net	(215,436)	30,908	7,553
Loss on sale of oil and gas properties	—	45,377	—
Stock-based compensation, net	25,878	29,373	11,689
Deferred income taxes	127,927	10,934	30,142
Non-cash interest expense, net	4,272	3,932	4,584
Other, net	2,379	3,704	6,036
Changes in operating assets and liabilities-			
Accounts receivable	(1,334)	11,557	(67,120)
Accounts payable	27,238	13,595	26,942
Accrued liabilities	(3,096)	(12,588)	21,832
Other, net	(5,219)	(5,467)	(5,757)
Net cash provided by operating activities from continuing operations	502,275	367,474	253,071
Net cash used in operating activities from discontinued operations	(656)	(623)	(845)
Net cash provided by operating activities	501,619	366,851	252,226
Cash Flows From Investing Activities			
Capital expenditures - oil and gas properties	(860,604)	(786,976)	(735,711)
Capital expenditures - other property and equipment	(750)	(968)	(4,176)
Acquisitions of oil and gas properties from Eagle Ford Minerals, LLC	(92,961)	—	—
Proceeds from sales of oil and gas properties, net	12,576	238,470	341,597
Other, net	1,063	39,589	(66,861)
Net cash used in investing activities from continuing operations	(940,676)	(509,885)	(465,151)
Net cash provided by (used in) investing activities from discontinued operations	(7,834)	124,533	(42,265)
Net cash used in investing activities	(948,510)	(385,352)	(507,416)
Cash Flows From Financing Activities			
Proceeds from borrowings and issuances	1,287,541	582,000	1,040,772
Debt repayments	(986,041)	(651,325)	(796,000)
Payments of debt issuance costs	(6,510)	(3,257)	(7,101)
Proceeds from common stock offerings, net of offering costs	—	189,686	—
Excess tax benefits from stock-based compensation	4,863	1,969	—
Proceeds from stock options exercised	437	1,253	107
Net cash provided by financing activities from continuing operations	300,290	120,326	237,778
Net cash provided by financing activities from discontinued operations	—	3,000	41,914
Net cash provided by financing activities	300,290	123,326	279,692
Net Increase (Decrease) in Cash and Cash Equivalents	(146,601)	104,825	24,502
Cash and Cash Equivalents, Beginning of Year	157,439	52,614	28,112
Cash and Cash Equivalents, End of Year	$10,838	$157,439	$52,614

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

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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 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 Utica Shale in Ohio, the Niobrara Formation in Colorado 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.

Reclassifications

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.

Discontinued Operations

On February 22, 2013, the Company closed on the sale of Carrizo UK Huntington Ltd, a wholly owned subsidiary of the Company ("Carrizo UK"), and all of its interest in the Huntington Field discovery, including a 15% non-operated working interest and certain overriding royalty interests, to a subsidiary of Iona Energy Inc. ("Iona Energy") for an agreed-upon price of $184.0 million, including the assumption and repayment by Iona Energy of the $55.0 million of borrowings outstanding under Carrizo UK's senior secured multicurrency credit facility as of the closing date. The liabilities, results of operations and cash flows associated with Carrizo UK have been classified as discontinued operations in the consolidated financial statements. Unless otherwise indicated, the information in these notes relate to the Company's continuing operations. Information related to discontinued operations is included in "Note 3. Discontinued Operations", "Note 14. Condensed Consolidating Financial Information" and "Note 17. Supplemental Disclosures about Oil and Gas Producing Activities (Unaudited)."

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 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, drilling requirements and royalty obligations. 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 impairments of unevaluated leasehold costs, fair values of derivative assets and liabilities, stock-based compensation, collectability of receivables, and in evaluating disputed claims, interpreting contractual arrangements (including royalty obligations and notional interest calculations) 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, counterparty creditworthiness, 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 Company presents the outstanding checks written against these zero-balance accounts as a component of accounts payable in the consolidated balance sheets. Outstanding checks included as a component of accounts payable totaled $70.5 million and $2.2 million as of December 31, 2014 and 2013, respectively.

Accounts Receivable and Accounts Payable

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, 2014 and 2013, the Company's allowance for doubtful accounts was zero and $0.6 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 customers 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 does not require collateral from its customers and joint interest owners. The Company generally has the right to withhold future revenue distributions to recover any non-payment of joint interest billings.

The Company's derivative instruments in a net asset position also subject the Company to a concentration of credit risk. See "Note 12. Derivative Instruments."

Major Customers

In 2014, two customers accounted for approximately 44% and 26% of the Company's oil and gas revenues. In 2013, two customers accounted for approximately 47% and 23% of the Company's oil and gas revenues. In 2012, two customers accounted for approximately 53% and 10% of the Company's oil and gas revenues.

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 and totaled $18.8 million, $15.0 million and $11.8 million for the years ended December 31, 2014, 2013 and 2012, 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 $26.20, $21.38 and $17.55 for the years ended December 31, 2014, 2013 and 2012, 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 added to the oil and gas property costs subject to amortization. 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. The Company expects to complete its evaluation of the majority of its unevaluated leaseholds within the next five years and exploratory wells in progress within the next year. Individually insignificant unevaluated leaseholds are grouped by major area and added to the oil and gas property costs subject to amortization based on the average primary lease term of the properties. The Company capitalized interest costs associated with its unproved properties totaling $34.5 million, $29.9 million and $24.8 million for the years ended December 31, 2014, 2013 and 2012, respectively. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unproved properties using a weighted-average interest rate based on outstanding borrowings.

Proceeds from the sale of proved and unproved oil and gas properties are recognized as a reduction of capitalized 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 2014, the Company did not have any sales of oil and gas properties that significantly altered such relationship. On February 22, 2013, the Company closed the sale of Carrizo UK, which included all of the Company's proved reserves in its U.K. cost center. As a result, in the first quarter of 2013, the Company recognized a $37.3 million pre-tax gain in "Net income from discontinued operations, net of income taxes" in the consolidated statements of income. Further, on October 31, 2013, the Company closed the sale of its remaining oil and gas properties in the Barnett. The proved reserves attributable to the Barnett sale represented 40% of the Company's proved reserves as of October 31, 2013, which significantly altered the relationship between capitalized costs and proved reserves of oil and gas attributable to the Company's U.S. cost center. As a result, the Company recognized a pre-tax loss on the sale of $45.4 million in "Loss on sale of oil and gas properties" in the consolidated statements of income in the fourth quarter of 2013. Other than the sales noted above, the Company has not had any sales that significantly altered the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center through December 31, 2014.

Capitalized costs, less accumulated amortization and 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. If the net capitalized costs exceed the cost center ceiling, the excess is recognized as an impairment of oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices in the future increase the cost center ceiling applicable to the subsequent period.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of oil and gas on the first calendar day of each month during the preceding 12-month period prior to the end of the current reporting period. Prices are held constant indefinitely and are not changed 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 because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment.

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.

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 that uses market data obtained from third-party sources, including quoted forward prices for oil and gas, discount rates and volatility factors. The carrying amounts of long-term debt under the Company's revolving credit facility approximate fair value as borrowings bear interest at variable rates of interest. 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 any unamortized discount and the notes bear interest at fixed rates of interest. The carrying amount of the EFM deferred purchase payment may not approximate fair value because the carrying amount is net of unamortized discount and the note is non-interest bearing. See "Note 7. Debt" and "Note 13. 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 when the production equipment and facilities are installed with an associated increase in oil and gas property costs. Asset retirement obligations are accreted 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. On an interim 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.

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.

Revenue Recognition

Oil and 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 an asset or 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, 2014 and 2013, the Company did not have any material production imbalances.

Derivative Instruments

The Company uses commodity derivative instruments, primarily fixed price swaps and costless collars, to reduce its exposure to commodity price volatility for a substantial, but varying, portion of its forecasted oil and gas production up to 36 months 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. Although the derivative instruments provide an economic hedge of the Company’s exposure to commodity price volatility, because the Company 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 income 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 reviews derivative instruments, including volumes, types of instruments and counterparties, on a quarterly basis. 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 12. Derivative Instruments” for further discussion of the Company’s derivative instruments.

Stock-Based Compensation

The Company recognized the following stock-based compensation expense associated with stock appreciation rights to be settled in cash (“SARs”), restricted stock awards and units and performance share awards for the periods indicated which is reflected as general and administrative expense in the consolidated statements of income:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Stock appreciation rights	$1,985	$17,303	($2,116)
Restricted stock awards and units	29,597	18,997	17,049
Performance share awards	1,395	—	—

	32,977	36,300	14,933
Less: amounts capitalized	(7,099)	(6,927)	(3,244)
Total stock-based compensation expense	$25,878	$29,373	$11,689
Income Tax Benefit	$9,059	$10,281	$4,449

Stock Appreciation Rights. For SARs, stock-based compensation expense is based on the fair value liability (using the Black-Scholes-Merton option pricing model) remeasured at each reporting period, recognized over the vesting period (generally three years) using the graded vesting method. For periods subsequent to vesting and prior to exercise, stock-based compensation expense is based on the fair value liability remeasured at each reporting period based on the intrinsic value of the SAR. The liability for SARs is classified as “Other current liabilities” for the portion of the awards that are vested or are expected to vest within the next 12 months, with the remainder classified as “Other liabilities.” SARs typically expire between four and seven years after the date of grant.

The Company uses the Black-Scholes-Merton option pricing model to compute the fair value of SARs, which requires the Company to make the following assumptions:

- The risk-free interest rate is based on the zero-coupon United States Treasury yield for the expected term at date of grant.
- 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 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.
- The expected term is based on historical exercises for various groups of directors, employees and independent contractors.

Restricted Stock Awards and Units. For restricted stock awards and units granted to employees, 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.

Performance Share Awards. For performance share awards, stock-based compensation expense is based on the grant-date fair value (using a Monte Carlo valuation model) and recognized over the three year vesting period using the straight-line method. The number of shares of common stock issuable upon vesting range from zero to 200% of the number of performance share awards granted based on the Company’s total shareholder return relative to an industry peer group over a three year performance period.

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 routinely assesses the realizability of its deferred tax assets by taxing jurisdiction and considers its estimate of future taxable income based on production of proved reserves at estimated future pricing in making such assessments. If the Company concludes that it is more likely than not that some portion or all of the benefit from deferred tax assets will not be realized, the deferred tax assets are reduced by a valuation allowance. The Company classifies interest and penalties associated with income taxes as interest expense. The Company applies the tax law ordering approach to determine the sequence in which deferred tax assets and other tax attributes are utilized.

Net Income From Continuing Operations Per Common Share

Supplemental net income from continuing operations per common share information is provided below:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands, except per share amounts)		
Income from Continuing Operations	$222,283	$21,858	$51,177
Basic weighted average common shares outstanding	45,372	40,781	39,591
Effect of dilutive instruments	822	574	435
Diluted weighted average common shares outstanding	46,194	41,355	40,026

Income from Continuing Operations Per Common Share			
Basic	$4.90	$0.54	$1.29
Diluted	$4.81	$0.53	$1.28

Basic income from continuing operations per common share is based on the weighted average number of shares of common stock outstanding during the period. 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 period which include restricted stock awards and units, performance share awards, stock options and warrants. The Company excludes the number of awards, units, options and warrants from the calculation of diluted weighted average shares outstanding when the grant date or exercise prices are greater than the average market prices of the Company's common stock for the corresponding period as the effect would be antidilutive to the computation. The Company includes the number of potentially dilutive common shares attributable to the performance share awards 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. The number of awards, units, options, warrants and performance share awards excluded for the years ended December 31, 2014, 2013 and 2012 were not significant.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry specific guidance in Subtopic 932-605, Extractive Activities- Oil and Gas- Revenue Recognition. This ASU requires entities to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods and services. This ASU is effective for annual and interim periods beginning in 2017, and is required to be adopted either retrospectively or as a cumulative-effect adjustment as of the date of adoption, with no early adoption permitted. The Company is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements.

3. Discontinued Operations

On February 22, 2013, the Company closed on the sale of Carrizo UK, and all of its interest in the Huntington Field discovery, including a 15% non-operated working interest and certain overriding royalty interests, to a subsidiary of Iona Energy for an agreed-upon price of $184.0 million, including the assumption and repayment by Iona Energy of the $55.0 million of borrowings outstanding under Carrizo UK's senior secured multicurrency credit facility as of the closing date. The liabilities of discontinued operations of $12.8 million and $28.3 million as of December 31, 2014 and 2013, respectively, relate to an accrual for estimated future obligations related to the sale. See "Note 2. Summary of Significant Accounting Policies—Use of Estimates" for further discussion of estimates and assumptions that may affect the reported amounts of liabilities related to the sale of Carrizo UK.

As a result of the sale of Carrizo UK, the Company reclassified the balances associated with our U.K. North Sea operations from held for sale as of December 31, 2012 to discontinued operations as of December 31, 2013.

The following table summarizes the amounts included in income from discontinued operations, net of income taxes presented in the consolidated statements of income for the years ended December 31, 2014, 2013 and 2012:

	For the Years Ended December 31,		
	2014	2013	2012
	(In thousands)		
Revenues	$—	$—	$—
Costs and expenses			
General and administrative	656	916	62
Accretion related to asset retirement obligations	—	36	363
Gain on sale of discontinued operations	—	(37,294)	—
Increase (decrease) in estimated future obligations	(7,638)	44	—
(Gain) loss on derivatives, net	34	109	(258)
Other (income) expense, net	—	(438)	591
Income (Loss) From Discontinued Operations Before Income Taxes	6,948	36,627	(758)
Income tax (expense) benefit	(2,888)	(14,802)	5,068
Income From Discontinued Operations, Net of Income Taxes	$4,060	$21,825	$4,310

Income Taxes

Carrizo UK is a disregarded entity for U.S. federal income tax purposes. Accordingly, the income tax (expense) benefit reflected above includes the Company's U.S. deferred income tax (expense) benefit associated with the income (loss) from discontinued operations before income taxes. The related U.S. deferred tax assets and liabilities have been classified as deferred income taxes of continuing operations in the consolidated balance sheets.

4. Eagle Ford Shale 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 Shale (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, subject to post-closing and working capital adjustments. The Company paid a total of $241.8 million, which consisted of approximately $93.0 million at closing, which represented $100.0 million of the agreed upon purchase price less estimated working capital adjustments of $7.0 million, and $148.8 million on February 13, 2015, which represented the remaining $150.0 million of the agreed upon purchase price, less final post-closing adjustments to the working capital adjustments estimated at closing of $1.2 million. 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 7. 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 revenues, operating expenses and capital expenditures 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:

Assets	(In thousands)
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

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and gas properties included estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows and a market-based weighted-average cost of capital rate. These inputs required significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

Included in the consolidated statement of income for the year ended December 31, 2014 are revenues of $13.1 million and income from continuing operations 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 has been prepared for informational purposes only and 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.

	For the Years Ended December 31,	
	2014	2013
	(In thousands, except per share data)	
	(Unaudited)	
Total revenues	$761,199	$575,721
Income From Continuing Operations	264,714	36,356
Income From Continuing Operations Per Common Share		
Basic	$5.83	$0.89
Diluted	$5.73	$0.88
Weighted Average Common Shares Outstanding		
Basic	45,372	40,781
Diluted	46,194	41,355

5. Property and Equipment, Net

As of December 31, 2014 and 2013, total property and equipment, net consisted of the following:

	December 31,	
	2014	2013
	(In thousands)	
Proved properties	$3,174,268	$2,182,226
Accumulated depreciation, depletion and amortization	(1,087,541)	(773,742)
Proved properties, net	2,086,727	1,408,484
Unproved properties, not being amortized		
Unevaluated leasehold and seismic costs	401,954	302,232
Exploratory wells in progress	71,402	30,196
Capitalized interest	61,841	45,009
Total unproved properties, not being amortized	535,197	377,437
Other property and equipment	16,017	15,260
Accumulated depreciation	(8,688)	(6,966)
Other property and equipment, net	7,329	8,294
Total property and equipment, net	$2,629,253	$1,794,215

Costs not subject to amortization totaling $535.2 million at December 31, 2014 were incurred in the following periods: $285.0 million in 2014 and $250.2 million in 2013.

For details regarding the Eagle Ford Shale Acquisition, see "Note 4. Eagle Ford Shale Acquisition."

Sales of Barnett Properties

During the fourth quarter of 2013, the Company sold its remaining oil and gas properties in the Barnett to EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., EnerVest Energy Institutional Fund XIII-WIC, L.P., and EV Properties, L.P., (collectively, "EnerVest"). Net proceeds received from the sale were approximately $191.8 million, which represents an agreed upon purchase price of approximately $218.0 million less net purchase price adjustments. Purchase price adjustments primarily relate to proceeds received by the

Company for sales of hydrocarbons from such properties between the effective date of July 1, 2013 and the closing date of October 31, 2013. The proved reserves attributable to the properties sold to EnerVest represented 40% of the Company’s proved reserves as of October 31, 2013 and the sale resulted in a significant alteration of the relationship between capitalized costs and proved reserves attributable to the Company's U.S. cost center. As a result, the Company recognized a pre-tax loss on the sale of $45.4 million as a component of operating income in the fourth quarter of 2013 rather than recognizing the proceeds as a reduction of proved oil and gas properties.

Sale and Acquisitions of Utica Properties

The Company elected on January 15, 2013 to exercise its option to increase its participating interest from 10% to 50% in unevaluated oil and gas properties dedicated to its Utica joint venture in the central and southern portions of the Utica play, by paying $63.1 million. In connection with this exercise of the Company's option to increase its participating interest in the Avista Utica joint venture properties, its right to receive distributions associated with properties owned by ACP III through "B Units" interest in ACP III that the Company acquired at the formation of the Utica joint venture was terminated.

On October 31, 2013, the Company completed the acquisition of additional interests in joint venture acreage located primarily in Guernsey and Noble counties, Ohio from ACP III. The transaction had an effective date of July 1, 2013, and the Company paid ACP III approximately $77.1 million in cash. Prior to the Company's acquisition from ACP III, the properties in the Avista Utica joint venture were held on an equal basis by the Company and ACP III. The transaction was initially funded with proceeds from the sale of the Company's remaining oil and gas properties in the Barnett as disclosed above. For additional information see "Note 11. Related Party Transactions."

Sales of Non-Core Marcellus and East Texas Properties

During the second half of 2013, the Company sold certain non-core proved producing oil and gas properties in East Texas and its interests in unevaluated acreage in non-core areas of Marcellus. Net proceeds received from the two transactions were $29.8 million, which represents an aggregate agreed upon price of $30.5 million less net purchase price adjustments. The proceeds from such sale were recognized as a reduction of proved oil and gas properties.

6. Income Taxes

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

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Current income tax (expense) benefit			
U.S. Federal	$—	$411	($411)
State	—	(141)	(403)
Total current income tax (expense) benefit	—	270	(814)
Deferred income tax expense			
U.S. Federal	(122,342)	(12,404)	(28,723)
State	(5,585)	(769)	(1,419)
Total deferred income tax expense	(127,927)	(13,173)	(30,142)
Total income tax expense from continuing operations	($127,927)	($12,903)	($30,956)

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

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Income from continuing operations before income taxes	$350,210	$34,761	$82,133
Income tax expense at the statutory rate	(122,574)	(12,166)	(28,747)
State income taxes, net of U.S. federal income tax benefit	(5,585)	(859)	(1,681)
Nondeductible expenses	—	—	(93)
Other	232	122	(435)
Total income tax expense from continuing operations	($127,927)	($12,903)	($30,956)

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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, 2014 and 2013, deferred tax assets and liabilities are comprised of the following:

	December 31, 2014	2013
	(In thousands)	
Deferred income tax assets		
Net operating loss carryforward - U.S. Federal and State	$56,876	$52,499
Asset retirement obligations	4,379	2,302
Stock-based compensation	7,867	7,563
Allowance for doubtful accounts	—	170
Fair value of derivative instruments	70	3,222
Other	2,989	2,471
Deferred income tax assets	72,181	68,227
Valuation allowance	(1,095)	(1,084)
Net deferred income tax assets	71,086	67,143
Deferred income tax liabilities		
Oil and gas properties	(134,518)	(76,549)
Fair value of derivative instruments	(75,175)	(3,249)
	(209,693)	(79,798)
Net deferred income tax liability	($138,607)	($12,655)

Deferred income tax assets and liabilities are classified as current or noncurrent based on the classification of the related asset or liability in the consolidated balance sheet except for deferred tax assets related to net operating loss carryforwards which is classified as current or noncurrent based on the periods the carryforwards are expected to be utilized. By taxing jurisdiction, all current deferred tax assets and liabilities are offset and presented as a net current deferred tax asset or liability and all noncurrent deferred tax assets and liabilities are offset and presented as a net noncurrent deferred tax asset or liability. At December 31, 2014 and 2013, the net deferred income tax asset (liability) is classified as follows:

	December 31, 2014	2013
	(In thousands)	
Net current deferred income tax asset (liability)	($61,258)	$4,201
Net noncurrent deferred income tax liability	(77,349)	(16,856)
Net deferred income tax liability	($138,607)	($12,655)

As of December 31, 2014, the Company had U.S. federal net operating loss carryforwards of approximately $185.6 million. If not utilized in earlier periods, the U.S. federal net operating loss will expire between 2019 and 2034. The realization of the deferred tax assets related to loss carryforwards is dependent on the Company’s ability to generate sufficient future taxable income in the U.S. within the applicable carryforward periods. During 2011 and 2012, the Company determined it was more likely than not that some of its state loss carryforwards would not be realized and accordingly, established valuation allowances totaling approximately $1.1 million. The Company believes it will be able to generate sufficient future taxable income in the U.S. within the carryforward periods. As such, the Company believes that it is more likely than not that its net deferred income tax assets will be fully realized except for those state loss carryforwards for which a valuation allowance has been established.

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, 2014, the Company believes an ownership change occurred in February 2005, which imposed an annual limitation of $12.6 million of the Company's taxable income that can be offset by the pre-change carryforwards. Because the Company's aggregate pre-change carryforward is $9.8 million, the Company does not believe it has a Section 382 limitation on the ability to utilize its U.S. loss carryforwards as of December 31, 2014. 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 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. The Company also receives a tax deduction during the period restricted stock awards and units vest, generally equal to the fair value of the awards or units on the vesting date. 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 $185.6 million but not reflected in the associated deferred tax asset were $34.6 million as of December 31, 2014. The Company expects to recognize the $12.1 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.

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 2014 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 2013 and 2014 tax years through 2015 and 2016, respectively. The Company received notice in January 2015 from the Large Business and International Division of the Internal Revenue Service that the Company's 2012 Federal Tax Return has been selected for examination. The examination commenced in February 2015. As of December 31, 2014, 2013 and 2012, the Company had no material uncertain tax positions.

7. Debt

Debt consisted of the following as of December 31, 2014 and 2013:

	December 31, 2014	2013
	(In thousands)	
Long-term debt		
8.625% Senior Notes due 2018	$600,000	$600,000
Unamortized discount for 8.625% Senior Notes	(3,444)	(4,178)
7.50% Senior Notes due 2020	600,000	300,000
Unamortized premium for 7.50% Senior Notes	1,465	—
Other long-term debt due 2028	4,425	4,425
Senior Secured Revolving Credit Facility due 2018	—	—
Deferred purchase payment	150,000	—
Unamortized discount for deferred purchase payment	(1,100)	—
Total long-term debt	$1,351,346	$900,247

8.625% Senior Notes and 7.50% Senior Notes

On November 2, 2010, the Company issued $400.0 million aggregate principal amount of 8.625% Senior Notes due 2018 in a private placement. On November 17, 2011, the Company issued an additional $200.0 million aggregate principal amount of 8.625% Senior Notes in a private placement. These notes were issued as "additional notes" under the indenture governing the 8.625% Senior Notes pursuant to which the Company had previously issued $400.0 million aggregate principal amount of 8.625% Senior Notes in November 2010, and under the indenture are treated as a single series with substantially identical terms as the 8.625% Senior Notes previously issued in November 2010. In June 2011 and February 2012, the Company completed the exchange of registered 8.625% Senior Notes for any and all of its then unregistered $400.0 million and $200.0 million aggregate principal amount of 8.625% Senior Notes, respectively.

Since October 15, 2014, the Company had the right to redeem all or a portion of the 8.625% Senior Notes at redemption prices decreasing from 104.313% to 100% of the principal amount on October 15, 2017, plus accrued and unpaid interest. If a Change of Control (as defined in the indenture governing the 8.625% Senior Notes) occurs, the Company may be required by holders to repurchase the 8.625% Senior Notes for cash at a price equal to 101% of the principal amount, plus any accrued and unpaid interest.

On September 10, 2012, the Company issued in a public offering $300.0 million aggregate principal amount of 7.50% Senior Notes due 2020. On October 30, 2014, the Company issued in a private placement an additional $300.0 million aggregate principal amount of 7.50% Senior Notes due 2020 at a price to the initial purchasers of 100.5% of par. In February 2015, the Company completed an exchange offer registered under the Securities Act of 1933, as amended, whereby registered 7.50% Senior Notes were exchanged for such privately placed 7.50% Senior Notes. The privately placed 7.50% Senior Notes have substantially identical terms, other than with respect to certain transfer restrictions and registration rights, as the exchanged 7.50% Senior Notes and our 7.50% Senior Notes that were issued on September 10, 2012. The Company may redeem all or a portion of the 7.50% Senior Notes at any time on or after September 15, 2016 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 certain equity offerings by the Company, the Company may at any time prior to September 15, 2015, subject to certain conditions, on one or more occasions, redeem up to 35% of the aggregate principal amount of the 7.50% Senior Notes at a redemption price of 107.50% of the principal amount, plus accrued and unpaid interest to the redemption date using the net cash proceeds of such equity offerings. Prior to September 15, 2016, the Company may redeem all or part of the 7.50% Senior Notes at 100% of the principal amount thereof, plus accrued and unpaid interest and a make whole premium (as defined in the indenture governing the original 7.50% Senior Notes). If a Change of Control (as defined in the indenture governing the original 7.50% Senior Notes) occurs, the Company may be required by holders to repurchase the 7.50% Senior Notes for cash at a price equal to 101% of the principal amount, plus any accrued and unpaid interest.

The indentures governing the 8.625% Senior Notes and the 7.50% 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. At December 31, 2014, the 8.625% Senior Notes and the 7.50% Senior Notes were guaranteed by all of the Company's existing Material Domestic Subsidiaries (as defined in the credit agreement governing the revolving credit facility).

Senior Secured Revolving Credit Facility

The Company has a senior secured revolving credit facility with a syndicate of banks that, as of December 31, 2014, had a borrowing base of $800.0 million, of which $685.0 million has been committed by the lenders with no borrowings and $0.6 million in letters of credit outstanding. The credit agreement governing the 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 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. A portion of the lender commitments under the credit agreement, in an aggregate amount not to exceed $30.0 million, may be used to issue letters of credit for the account of the Company or certain of its subsidiaries.

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 80% of the proved reserve value of the oil and gas properties included in the determination of the borrowing base.

Amounts 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, and which are included as a component of interest expense.

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%	0.50%	1.50%	0.375%
Greater than or equal to 25% but less than 50%	0.75%	1.75%	0.375%
Greater than or equal to 50% but less than 75%	1.00%	2.00%	0.500%
Greater than or equal to 75% but less than 90%	1.25%	2.25%	0.500%
Greater than or equal to 90%	1.50%	2.50%	0.500%

The Company is subject to certain covenants under the terms of the credit agreement, which include the maintenance of the following financial covenants determined as of the last day of each quarter: (1) a ratio of Total Debt to EBITDA (as defined in the credit agreement) of not more than 4.00 to 1.00; and (2) a Current Ratio (as defined in the credit agreement) of not less than 1.00 to 1.00. As defined in the credit agreement, Total Debt is net of cash and cash equivalents, EBITDA is for the last four quarters after giving pro forma effect to certain material acquisitions and dispositions of oil and gas properties, and the Current Ratio includes an add back of the unused portion of lender commitments. As of December 31, 2014, the ratio of Total Debt to EBITDA was 2.33 to 1.00 and the Current Ratio was 2.35 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 amounts outstanding under the credit agreement are dependent on 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).

Deferred Purchase Payment

On October 24, 2014, the Company agreed to pay EFM $150.0 million representing the remaining portion of the agreed upon purchase price of $250.0 million associated with the Eagle Ford Shale Acquisition. The acquisition date fair value of the deferred purchase payment was $147.4 million. The deferred purchase payment is non-interest bearing and therefore was discounted using the effective interest method. This discount on the EFM deferred purchase payment of $2.6 million will be accreted to interest expense from the acquisition date through February 13, 2015. The Company has the intent and ability to refinance this deferred purchase payment on a long-term basis with the available capacity under its revolving credit facility, and accordingly, the deferred purchase payment has been classified as long-term debt as of December 31, 2014. The deferred purchase payment was paid on February 13, 2015. See "Note 4. Eagle Ford Shale Acquisition" for further discussion.

8. Asset Retirement Obligations

The following table sets forth asset retirement obligations for the years ended December 31, 2014 and 2013:

	Year Ended December 31,	
	2014	2013
	(In thousands)	
Asset retirement obligations at beginning of period	$7,356	$6,159
Liabilities incurred	6,284	3,348
Increase due to acquisition of oil and gas properties	423	—
Liabilities settled	(1,784)	(498)
Reduction due to sales of oil and gas properties	—	(2,473)
Accretion expense	710	471
Revisions of previous estimates	(477)	349
Asset retirement obligations at end of period	12,512	7,356
Asset retirement obligations due within one year included in "Other current liabilities"	(325)	(780)
Long-term asset retirement obligations	$12,187	$6,576

9. 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 natural 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.

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Rent expense included in general and administrative expense for the years ended December 31, 2014, 2013 and 2012 was $1.9 million, $1.9 million, and $1.8 million, respectively, and includes rent expense primarily for the Company's corporate office and field offices. At December 31, 2014, total minimum commitments from long-term, non-cancelable operating leases, drilling rigs, completion services and pipeline volume commitments are as shown in the table below. The total minimum commitments related to the drilling rigs and completion services 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.

	Amount (In thousands)
2015	$55,435
2016	36,020
2017	26,424
2018	11,141
2019	6,493
2020 and thereafter	16,934
Total	$152,447

10. Shareholders' Equity and Stock Incentive Plans

Shareholders' Equity

Common Stock. In November 2013, the Company sold 4.5 million shares of its common stock in an underwritten public offering at a price to the underwriter of $42.24 per share, and received proceeds of approximately $189.7 million, net of offering costs.

Warrants. On November 24, 2009, the Company entered into an agreement with an unrelated third party and its affiliate, which expired by its terms on May 31, 2011 under which the Company issued warrants to purchase shares of common stock. In 2014 and 2013, the Company issued no warrants. Warrants outstanding as of December 31, 2014 totaled 118,200. The warrants have an expiration date of August 21, 2017, an exercise price of $22.09, which may be exercised on a "cashless" basis, and are subject to anti-dilution adjustments.

Stock Incentive 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 directors, employees and independent contractors. 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 of up to 10,822,500 shares (subject to certain limitations on restricted stock and restricted stock units) under the Incentive Plan and through December 31, 2014, has issued stock options, restricted stock awards, restricted stock units and performance share awards covering 6,526,862 shares, net of forfeitures and excluding SARs the Company has elected to settle in cash. 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 that may only be settled in cash to employees and independent contractors.

Stock Options. No stock options were granted under the Incentive Plan during 2014, 2013 or 2012. The table below summarizes the activity for stock options for each of the three years ended December 31, 2014, 2013 and 2012:

	Shares	Weighted-Average Exercise Prices	Weighted-Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)
For the Year Ended December 31, 2012				
Outstanding, beginning of period	263,354	$7.11		
Granted	—	—		
Exercised	(20,500)	$5.50		
Forfeited	—	—		
Outstanding, end of period	242,854	$7.24		
Exercisable, end of period	242,854	$7.24		
For the Year Ended December 31, 2013				
Outstanding, beginning of period	242,854	$7.24		
Granted	—	—		
Exercised	(206,501)	$6.07		
Forfeited	—	—		
Outstanding, end of period	36,353	$13.91		
Exercisable, end of period	36,353	$13.91		
For the Year Ended December 31, 2014				
Outstanding, beginning of period	36,353	$13.91		
Granted	—	—		
Exercised	(33,086)	$13.20		
Forfeited	—	—		
Expired	(834)	$27.25		
Outstanding, end of period	2,433	$19.02	0.52	$0.1
Exercisable, end of period	2,433	$19.02	0.52	$0.1

As of December 31, 2014, all stock options were vested and accordingly, the Company had no unrecognized compensation costs related to outstanding stock options. The total intrinsic value (market price at date of exercise less the exercise price) of stock options exercised during the years ended December 31, 2014, 2013 and 2012 was $1.3 million, $4.4 million, and $0.4 million, respectively, and the Company received $0.4 million, $1.3 million, and $0.1 million in cash in connection with stock option exercises for the years ended December 31, 2014, 2013 and 2012, respectively.

Stock Appreciation Rights. During the years ended December 31, 2014, 2013 and 2012, the Company granted zero, 282,296 and 193,336, respectively of SARs under the Cash SAR Plan and SARs under the Incentive Plan that can only be settled in cash. All SARs that have been granted by the Company contain performance and service conditions. The performance conditions have been met for all awards. The table below summarizes the activity for SARs for each of the three years ended December 31, 2014, 2013 and 2012:

	Shares		Weighted-Average Exercise Prices	Weighted-Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)
For the Year Ended December 31, 2012					
Outstanding, beginning of period	849,782		$22.02		
Granted	193,336		$25.56		
Exercised	(7,295	)	$20.22		
Forfeited	—		—		
Outstanding, end of period	1,035,823		$22.69		
Exercisable, end of period	613,934		$20.70		
For the Year Ended December 31, 2013					
Outstanding, beginning of period	1,035,823		$22.69		
Granted	282,296		$28.68		
Exercised	(207,184	)	$19.30		
Forfeited	(24,704	)	$27.77		
Outstanding, end of period	1,086,231		$24.78		
Exercisable, end of period	681,867		$22.55		
For the Year Ended December 31, 2014					
Outstanding, beginning of period	1,086,231		$24.78		
Granted	—		—		
Exercised	(321,033	)	$30.24		
Forfeited	—		—		
Outstanding, end of period	765,198		$22.49	2.05	$14.5
Exercisable, end of period	587,481		$20.78	1.98	$12.2

As of December 31, 2014, the liability for SARs outstanding was $14.8 million, of which, $13.9 million is classified as “Other current liabilities”, with the remainder of $0.9 million classified as “Other liabilities”. As of December 31, 2013, the liability for SARs outstanding was $20.6 million, of which $19.3 million is classified as “Other current liabilities” with the remainder of $1.3 million classified as “Other liabilities”. The Company paid $7.8 million, $3.9 million and $0.1 million, in connection with SARs exercised during the years ended December 31, 2014, 2013 and 2012, respectively. The following table summarizes the weighted-average assumptions used in the Black-Scholes-Merton option pricing model to calculate the fair value of the SARs granted during 2013 and 2012:

	2013		2012	
Grant date fair value	$13.36		$12.23	
Volatility factor	44.5	%	48.2	%
Dividend yield	—	%	—	%
Risk-free interest rate	1.0	%	0.4	%
Expected term (in years)	3.5		3.0	

As of December 31, 2014, unrecognized compensation costs related to unvested SARs was $0.6 million and will be recognized as stock-based compensation expense, net of amounts capitalized over a weighted-average period of 1.49 years.

Restricted Stock Awards and Units. The Company began issuing restricted stock awards in 2005 and restricted stock units in 2009. Although shares of common stock are not released to the employee until vesting, restricted stock awards have the right to vote and accordingly, restricted stock awards are considered issued and outstanding at the date of grant. Restricted stock units do not have the right to vote and are not considered issued and outstanding until converted into common shares and released to the employee upon vesting. The table below summarizes restricted stock award and unit activity for each of the years ended December 31, 2014, 2013 and 2012:

	Shares/ Units		Weighted-Average Grant Date Fair Value
For the Year Ended December 31, 2012			
Unvested restricted stock awards and units, beginning of period	800,498		$27.96
Granted	854,292		$25.25
Vested	(488,992	)	$25.63
Forfeited	(19,524	)	$27.61
Unvested restricted stock awards and units, end of period	1,146,274		$26.95
For the Year Ended December 31, 2013			
Unvested restricted stock awards and units, beginning of period	1,146,274		$26.95
Granted	932,763		$28.16
Vested	(557,136	)	$25.98
Forfeited	(77,034	)	$26.03
Unvested restricted stock awards and units, end of period	1,444,867		$28.03
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

As of December 31, 2014, unrecognized compensation costs related to unvested restricted stock awards and units was $25.4 million and will be recognized as stock-based compensation expense, net of amounts capitalized over a weighted-average period of 1.90 years. The 2014, 2013 and 2012 grants of certain restricted stock units contained performance and service conditions. The performance conditions have been met for all awards.

Performance Share Awards. In March 2014, the Company granted 56,342 market-based performance share awards. The performance awards have a performance period of three years, contain predetermined market and performance conditions established by the Compensation Committee, and, if the market and performance conditions are met, will cliff vest three years from the date of grant. The number of performance shares to be earned is subject to a market condition, which is based on the total shareholder return (“TSR”) of the Company’s common stock relative to the TSR achieved by a defined peer group of 12 other companies at the end of the performance period. The range of performance shares which may be earned by an award recipient ranges from zero and 200% of the initial performance shares granted.

The grant date fair value of the performance share awards was determined using a Monte Carlo valuation model prepared by an independent third party. The grant date fair value of the performance share awards as determined by the Monte Carlo valuation model was $68.15, which was based on the following assumptions:

	2014	
Number of simulations	500,000	
Grant price	$53.96	
Volatility factor	49.9	%
Dividend yield	—	%
Risk-free interest rate	0.9	%
Expected term (in years)	2.97	

The fair value of the performance share awards of $3.8 million will be amortized on a straight-line basis and recognized as stock-based compensation expense, net of amount capitalized over the requisite service period of three years. All compensation cost related to the performance share awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. As of December 31, 2014, unrecognized compensation costs related to the 56,342 unvested performance share awards was $2.4 million and will be recognized as stock-based compensation expense, net of amounts capitalized over a weighted-average period of 2.24 years. The 2014 grants of certain performance share awards contained performance and service conditions. The performance conditions have been met for all awards.

11. Related Party Transactions

Avista Utica Joint Venture. Effective September 2011, the Company's wholly-owned subsidiary, Carrizo (Utica) LLC, entered into a joint venture in the Utica Shale with ACP II Marcellus LLC ("ACP II"), which is also one of the Company's joint venture partners in the Marcellus Shale, and ACP III Utica LLC ("ACP III"), both affiliates of Avista Capital Partners, LP, a private equity fund (collectively with ACP II and ACP III, "Avista"). During the term of the Avista Utica joint venture, the joint venture partners acquired and sold acreage and the Company 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 the Company's purchase of certain ACP III assets discussed below.

On January 15, 2013, the Company exercised an option to increase its participating interest in the Avista Utica joint venture properties by paying $63.1 million for an additional 40% in the remaining Avista Utica joint venture properties. The Company and Avista also agreed that after the option was exercised, the Company's participating interest in subsequently acquired properties within the then existing area of mutual interest continued to be 10% and Avista's participating interest continued to be 90%, and the Company was granted an additional option to increase its 10% ownership in such subsequently acquired properties to 50% at 8.625% above acreage cost and associated improvements (compounded monthly following Avista's contribution of purchase proceeds). Instead of exercising this option, the Company and Avista agreed that the Company could instead elect to acquire additional properties on an equal basis with Avista. In connection with the January 2013 exercise of the Company's option to increase its participating interest in the Avista Utica joint venture properties, its right to receive distributions associated with properties owned by ACP III through "B Units" interest in ACP III that the Company acquired at the formation of the Utica joint venture was terminated.

On October 31, 2013, the Company completed the acquisition of acreage located primarily in Guernsey and Noble counties, Ohio from Avista. This transaction had an effective date of July 1, 2013, and the Company paid Avista approximately $77.1 million in cash. Prior to the Company's acquisition from ACP III, the properties in the Avista Utica joint venture were held on an equal basis by the Company and Avista. This transaction was initially funded with proceeds from the sale of the Company's remaining oil and gas properties in the Barnett to EnerVest. After giving effect to this 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 agreement 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 as well as the Avista Transaction and the other acquisition transactions described above with Avista were each separately approved by a special committee of the Company's independent directors. In determining whether to approve or disapprove a transaction, such special committee has in the Avista Transaction and generally in other transactions since the beginning of the last fiscal year, determined whether the transaction is desirable and in the best interest of the Company. In transactions prior to the recent Avista Transaction, the special committee has evaluated whether transactions are fair to the Company and its shareholders on the same basis as comparable arm's length transactions. The committee has applied in the Avista Transaction, and may in other transactions also apply, standards under relevant debt agreements if required.

Advances to and from Avista and Affiliates. As of December 31, 2014, related party receivable on the consolidated balance sheets included $1.9 million, representing the net amounts ACP II and ACP III owes the Company related to activity within the Avista Marcellus and Avista Utica joint ventures. As of December 31, 2013, related party receivable and related party payable on the consolidated balance sheets included $6.6 million and $2.8 million, respectively, representing the net amount ACP II owed the Company related to activity within the Avista Marcellus joint venture and the net amount the Company owed ACP III related to activity within the Avista Utica joint venture, respectively.

12. Derivative Instruments

The Company uses commodity derivative instruments, primarily fixed price swaps and costless collars, to reduce its exposure to commodity price volatility for a substantial, but varying, portion of its forecasted oil and gas production up to 36 months and thereby achieve a more predictable level of cash flows to support the Company's drilling and completion capital expenditure program. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not enter into derivative instruments for speculative or trading purposes.

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. 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. The fair value of derivative instruments where the Company is in a net asset position with its counterparties as of December 31, 2014 and 2013 totaled $214.8 million and $9.3 million, respectively, and is summarized by counterparty in the table below:

Counterparty	December 31, 2014		December 31, 2013	
Wells Fargo	37	%	23	%
Societe Generale	26	%	31	%
Credit Suisse	24	%	46	%
Regions	8	%	—	%
Union Bank	4	%	—	%
Royal Bank of Canada	1	%	—	%
Total	100	%	100	%

The counterparties to the Company's derivative instruments are lenders under the Company's credit agreement. Because each of the lenders have investment grade credit ratings, 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. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties to its derivative instruments. Although the Company does not currently anticipate such nonperformance, it continues to monitor the credit ratings of its counterparties.

For the years ended December 31, 2014, 2013 and 2012, the Company recorded in the consolidated statements of income a gain on derivatives, net of $201.9 million, a loss on derivatives, net of $18.4 million, and a gain on derivatives, net of $31.4 million, respectively.

The following sets forth a summary of the Company's crude oil derivative positions at average NYMEX prices as of December 31, 2014.

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Weighted Average Short Put Price ($/Bbl)	Weighted Average Put Spread ($/Bbl)
January - December 2015	Fixed Price Swaps	10,370	$92.97			
	Costless Collars	700	$90.00	$100.65		
	Three-way Collars	1,000	$85.00	$105.00	$65.00	$20.00
January - December 2016	Fixed Price Swaps	3,000	$91.09			
	Three-way Collars	667	$85.00	$104.00	$65.00	$20.00

The following sets forth a summary of the Company's natural gas derivative positions at average NYMEX prices as of December 31, 2014.

Period	Type of Contract	Volume (in MMBtu/d)	Weighted Average Floor Price ($/MMBtu)
January - December 2015	Fixed Price Swaps	30,000	$4.29

On February 11, 2015, the Company entered into derivative transactions offsetting its existing crude oil derivative positions covering the periods from March 2015 through December 2016. Additionally, on February 13, 2015, the Company entered into costless collars for the periods from March 2015 through December 2016 which will continue to provide the Company with solid downside protection on 12,200 Bbls/d in 2015 and 4,000 Bbls/d in 2016 of crude oil at prices below the floor of $50.00 per Bbl yet allow the Company to benefit from an increase in crude oil prices up to the ceiling of $66.46 per Bbl in 2015 and $76.50 per Bbl in 2016. See "Note 16. Subsequent Events (Unaudited)" for additional information regarding the Company's derivative instruments.

13. 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 location and amounts of the Company's assets and liabilities measured at fair value on a recurring basis as presented in the consolidated balance sheets as of December 31, 2014 and 2013. All items included in the tables below are Level 2 inputs within the fair value hierarchy:

	December 31, 2014		
	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)	$183,625	($12,524)	$171,101
Derivative assets (noncurrent)	44,725	(1,041)	43,684
Derivative liabilities			
Other current liabilities	(12,707)	12,524	(183)
Other liabilities (noncurrent)	(1,058)	1,041	(17)
Total	$214,585	$—	$214,585

	December 31, 2013		
	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)	$2,389	($2,389)	$—
Derivative assets (noncurrent)	11,709	(2,425)	9,284
Derivative Liabilities			
Other current liabilities	(12,336)	2,389	(9,947)
Other liabilities (noncurrent)	(2,613)	2,425	(188)
Total	($851)	$—	($851)

The fair values of the Company's derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for oil and gas, discount rates and volatility factors. The fair values are also compared to the values provided by the counterparty for reasonableness and are adjusted for the counterparties' credit quality for derivative assets and the Company's credit quality for derivative liabilities. To date, adjustments for credit quality have not had a material impact on the fair values.

The derivative asset and liability fair values reported in the consolidated balance sheets are as of a particular point in time and subsequently change as these estimates are revised to reflect actual results, changes in 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. 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 in or out of Levels 1 or 2 for the years ended December 31, 2014 and 2013.

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, and the EFM deferred purchase payment, which is classified as Level 2 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 following table presents the carrying amounts and fair values of the Company's senior notes and other long-term debt, based on quoted market prices, as of December 31, 2014 and 2013, and the carrying amount and fair value of the Company's EFM deferred purchase payment, based on indirect observable market rates as of December 31, 2014.

	December 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
8.625% Senior Notes due 2018	$596,555	$597,000	$595,822	$644,978
7.50% Senior Notes due 2020	600,000	573,000	300,000	327,000
Other long-term debt due 2028	4,425	4,071	4,425	4,115
Deferred purchase payment	148,900	148,558	—	—

14. 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 as of December 31, 2014 and December 31, 2013, and for the three years ended December 31, 2014, 2013 and 2012 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.

Investments in subsidiaries are accounted for by the respective parent company using the equity method for purposes of this presentation. Results of operations of subsidiaries are therefore reflected in the parent company's investment accounts and earnings. The principal elimination entries set forth below eliminate investments in subsidiaries and intercompany balances and transactions. Typically in a condensed consolidating financial statement, the net income and equity of the parent company equals the net income and equity of the consolidated entity. The Company's oil and gas properties are accounted for using the full cost method of accounting whereby impairments and DD&A are calculated and recorded on a country by country basis. However, when calculated separately on a legal entity basis, the combined totals of parent company and subsidiary impairments and DD&A can be more or less than the consolidated total as a result of differences in the properties each entity owns including amounts of costs incurred, production rates, reserve mix, future development costs, etc. Accordingly, elimination entries are required to eliminate any differences between consolidated and parent company and subsidiary company combined impairments and DD&A.

CARRIZO OIL & GAS, INC.
CONDENSED CONSOLIDATING BALANCE SHEETS
(In thousands)

	December 31, 2014				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$2,380,445	$245,051	$111	($2,346,986)	$278,621
Total property and equipment, net	613	2,562,029	39,939	26,672	2,629,253
Investment in subsidiaries	233,173	—	—	(233,173)	—
Other assets	140,774	—	—	(67,172)	73,602
Total Assets	$2,755,005	$2,807,080	$40,050	($2,620,659)	$2,981,476
Liabilities and Shareholders’ Equity					
Current liabilities	$296,686	$2,434,649	$39,955	($2,346,986)	$424,304
Long-term liabilities	1,364,793	139,353	—	(50,415)	1,453,731
Total shareholders’ equity	1,093,526	233,078	95	(223,258)	1,103,441
Total Liabilities and Shareholders’ Equity	$2,755,005	$2,807,080	$40,050	($2,620,659)	$2,981,476

	December 31, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Total current assets	$1,820,069	$168,718	$—	($1,709,026)	$279,761
Total property and equipment, net	2,797	1,768,553	2,058	20,807	1,794,215
Investment in subsidiaries	61,619	—	—	(61,619)	—
Other assets	69,686	—	—	(32,902)	36,784
Total Assets	$1,954,171	$1,937,271	$2,058	($1,782,740)	$2,110,760
Liabilities and Shareholders’ Equity					
Current liabilities	$201,486	$1,828,314	$2,061	($1,709,026)	$322,835
Long-term liabilities	922,571	47,335	—	(23,585)	946,321
Total shareholders’ equity	830,114	61,622	(3)	(50,129)	841,604
Total Liabilities and Shareholders’ Equity	$1,954,171	$1,937,271	$2,058	($1,782,740)	$2,110,760

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

	For the 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

	For the Year Ended December 31, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$6,490	$513,692	$—	$—	$520,182
Total costs and expenses	134,874	349,782	3	762	485,421
Income (Loss) From Continuing Operations Before Income Taxes	(128,384)	163,910	(3)	(762)	34,761
Income tax (expense) benefit	44,934	(57,369)	—	(468)	(12,903)
Equity in income of subsidiaries	106,538	—	—	(106,538)	—
Income (Loss) From Continuing Operations	$23,088	$106,541	($3)	($107,768)	$21,858
Income From Discontinued Operations, Net of Income Taxes	21,825	—	—	—	21,825
Net Income (Loss)	$44,913	$106,541	($3)	($107,768)	$43,683

	For the Year Ended December 31, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$20,195	$347,985	$—	$—	$368,180
Total costs and expenses	56,817	241,883	—	(12,653)	286,047
Income (Loss) From Continuing Operations Before Income Taxes	(36,622)	106,102	—	12,653	82,133
Income tax (expense) benefit	12,658	(37,136)	—	(6,478)	(30,956)
Equity in income of subsidiaries	73,150	—	—	(73,150)	—
Income From Continuing Operations	$49,186	$68,966	$—	($66,975)	$51,177
Income From Discontinued Operations, Net of Income Taxes	126	—	4,184	—	4,310
Net Income	$49,312	$68,966	$4,184	($66,975)	$55,487

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

	For the 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

	For the Year Ended December 31, 2013				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities from continuing operations	($55,888)	$423,366	($4)	$—	$367,474
Net cash used in investing activities from continuing operations	(86,322)	(513,710)	(2,057)	92,204	(509,885)
Net cash provided by financing activities from continuing operations	120,326	90,143	2,061	(92,204)	120,326
Net cash provided by (used in) discontinued operations	127,429	—	(519)	—	126,910
Net increase (decrease) in cash and cash equivalents	105,545	(201)	(519)	—	104,825
Cash and cash equivalents, beginning of year	51,894	201	519	—	52,614
Cash and cash equivalents, end of year	$157,439	$—	$—	$—	$157,439

	For the Year Ended December 31, 2012				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities from continuing operations	$75,546	$177,525	$—	$—	$253,071
Net cash used in investing activities from continuing operations	(280,564)	(493,145)	—	308,558	(465,151)
Net cash provided by financing activities from continuing operations	237,778	308,558	—	(308,558)	237,778
Net cash used in discontinued operations	—	—	(1,196)	—	(1,196)
Net increase (decrease) in cash and cash equivalents	32,760	(7,062)	(1,196)	—	24,502
Cash and cash equivalents, beginning of year	19,134	7,263	1,715	—	28,112
Cash and cash equivalents, end of year	$51,894	$201	$519	$—	$52,614

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15. Supplemental Cash Flow Information

Supplemental disclosures to the consolidated statements of cash flows are presented below:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Net cash provided by operating activities:			
Cash paid for interest, net of amounts capitalized	$49,379	$50,770	$43,629
Cash paid for income taxes	—	505	587
Non-cash investing and financing activities:			
Capital expenditures included in accounts payable and accrued capital expenditures	$176,886	$114,988	$82,727
Purchase price adjustments related to the Eagle Ford Shale Acquisition	3,197	—	—
EFM deferred purchase payment	148,900	—	—

16. Subsequent Events (Unaudited)

On February 11, 2015, the Company entered into derivative transactions offsetting its existing crude oil derivative positions covering the periods from March 2015 through December 2016. See “Note 12. Derivative Instruments” for a summary of the Company’s existing crude oil hedge positions as of December 31, 2014.The following sets forth a summary of the Company’s derivative positions for which offsetting derivative transactions were executed:

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)	Weighted Average Short Put Price ($/Bbl)
March - December 2015	Fixed Price Swaps	10,370	$55.48		
	Costless Collars	700	$90.00	$100.65	
	Three-way Collars	1,000	$85.00	$105.00	$65.00
January - December 2016	Fixed Price Swaps	3,000	$62.11		
	Three-way Collars	667	$85.00	$104.00	$65.00

As a result of the offsetting derivative transactions, the Company has locked in $166.4 million of cash flows which will be received as the derivative contracts settle in 2015 and 2016 and the Company will recognize an $8.4 million gain on derivatives, net in the first quarter of 2015 which represents the increase in fair value of the derivatives from December 31, 2014 to February 11, 2015.

On February 13, 2015, the Company entered into costless collars for the periods from March 2015 through December 2016 which will continue to provide the Company with solid downside protection at crude oil prices below the floor price yet allow the Company to benefit from an increase in the price of crude oil up to the ceiling price. The following sets forth a summary of the Company’s costless collars transactions:

Period	Type of Contract	Volumes (in Bbls/d)	Weighted Average Floor Price ($/Bbl)	Weighted Average Ceiling Price ($/Bbl)
March - December 2015	Costless Collars	12,200	$50.00	$66.46
January - December 2016	Costless Collars	4,000	$50.00	$76.50

17. Supplemental Disclosures about Oil and Gas Producing Activities (Unaudited)

As of December 31, 2014 and 2013, the Company's oil and gas properties are located in the U.S. As of December 31, 2012, the Company's oil and gas properties were located in the U.S. and U.K. North Sea. All information presented as "U.K." in this footnote relates to the U.K. North Sea discontinued operations. For additional information see "Note 3. Discontinued Operations."

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities are summarized below:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
U.S.			
Property acquisition costs			
Proved property acquisition costs	$183,633	$—	$—
Unproved property acquisition costs	215,021	254,099	139,344
Total property acquisition costs	398,654	254,099	139,344
Exploration costs	194,956	106,329	211,289
Development costs	530,268	423,871	374,391
Total costs incurred	$1,123,878	$784,299	$725,024
U.K.			
Property acquisition costs			
Proved property acquisition costs	$—	$—	$—
Unproved property acquisition costs	—	—	11,135
Total property acquisition costs	—	—	11,135
Exploration costs	—	—	—
Development costs	—	—	36,261
Total costs incurred	$—	$—	$47,396
Total Worldwide			
Property acquisition costs			
Proved property acquisition costs	$183,633	$—	$—
Unproved property acquisition costs	215,021	254,099	150,479
Total property acquisition costs	398,654	254,099	150,479
Exploration costs	194,956	106,329	211,289
Development costs	530,268	423,871	410,652
Total costs incurred	$1,123,878	$784,299	$772,420

Costs incurred excludes capitalized interest on U.S. unproved properties of $34.5 million, $29.9 million, and $24.8 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Proved Oil and Gas Reserve Quantities

Proved reserves are generally those quantities of oil and 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 proved 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 are generally proved 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 oil and gas reserve quantities at December 31, 2014 and December 31, 2013, and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company, L.P. Proved oil and gas reserve quantities at December 31, 2012, and the related discounted future net cash flows before income taxes are based on estimates prepared by LaRoche Petroleum Consultants, Ltd., Ryder Scott Company, L.P., and Fairchild and Wells, Inc. Such estimates have been prepared in accordance with guidelines established by the SEC.

The Company's net proved oil and gas reserves and changes in net proved oil and gas reserves, which are located in the U.S. and U.K., are summarized below:

	Crude Oil and Condensate (MBbls)			Natural Gas Liquids (MBbls)		
	U.S.	U.K.	Worldwide	U.S.	U.K.	Worldwide
Proved reserves:						
January 1, 2012	25,101	5,437	30,538	4,121	—	4,121
Extensions and discoveries	15,403	—	15,403	1,750	—	1,750
Revisions of previous estimates	1,760	(196)	1,564	740	—	740
Sales of reserves in place	(327)	—	(327)	(923)	—	(923)
Production	(2,862)	—	(2,862)	(305)	—	(305)
December 31, 2012	39,075	5,241	44,316	5,383	—	5,383
Extensions and discoveries	27,295	—	27,295	2,992	—	2,992
Revisions of previous estimates	778	—	778	308	—	308
Sales of reserves in place	(876)	(5,241)	(6,117)	—	—	—
Production	(4,231)	—	(4,231)	(531)	—	(531)
December 31, 2013	62,041	—	62,041	8,152	—	8,152
Extensions and discoveries	29,793	—	29,793	3,681	—	3,681
Revisions of previous estimates	3,046	—	3,046	1,270	—	1,270
Purchases of reserves in place	12,730	—	12,730	1,335	—	1,335
Production	(6,906)	—	(6,906)	(925)	—	(925)
December 31, 2014	100,704	—	100,704	13,513	—	13,513
Proved developed reserves:						
December 31, 2012	12,675	5,241	17,916	1,620	—	1,620
December 31, 2013	18,321	—	18,321	2,779	—	2,779
December 31, 2014	35,238	—	35,238	5,294	—	5,294
Proved undeveloped reserves:						
December 31, 2012	26,400	—	26,400	3,763	—	3,763
December 31, 2013	43,720	—	43,720	5,373	—	5,373
December 31, 2014	65,466	—	65,466	8,219	—	8,219

Crude oil, condensate and natural gas liquids extensions and discoveries are primarily attributable to the following:

2014	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Eagle Ford Shale and the Niobrara Formation.
2013	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Eagle Ford Shale and the Niobrara Formation.
2012	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Eagle Ford Shale and the Niobrara Formation.

Crude oil, condensate and natural gas liquids purchases of reserves in place are primarily attributable to the following:

2014	Acquisition of proved developed and undeveloped reserves from Eagle Ford Minerals, LLC.

Crude oil, condensate and natural gas liquids sales of reserves in place are primarily attributable to the following:

2013	Sales of U.K. North Sea properties to Iona Energy during the first quarter and sales of U.S. properties in East Texas in the third quarter.

	Natural Gas (MMcf)			Oil-Equivalent Proved Reserves (MBoe)		
	U.S.	U.K.	Worldwide	U.S.	U.K.	Worldwide
Proved reserves:						
January 1, 2012	722,847	4,838	727,685	149,697	6,243	155,940
Extensions and discoveries	72,916	—	72,916	29,305	—	29,305
Revisions of previous estimates	(20,996)	(174)	(21,170)	(999)	(225)	(1,224)
Sales of reserves in place	(313,483)	—	(313,483)	(53,497)	—	(53,497)
Production	(37,612)	—	(37,612)	(9,436)	—	(9,436)
December 31, 2012	423,672	4,664	428,336	115,070	6,018	121,088
Extensions and discoveries	73,360	—	73,360	42,514	—	42,514
Revisions of previous estimates	29,819	—	29,819	6,055	—	6,055
Sales of reserves in place	(307,472)	(4,664)	(312,136)	(52,121)	(6,018)	(58,139)
Production	(31,422)	—	(31,422)	(9,999)	—	(9,999)
December 31, 2013	187,957	—	187,957	101,519	—	101,519
Extensions and discoveries	30,343	—	30,343	38,531	—	38,531
Revisions of previous estimates	18,913	—	18,913	7,469	—	7,469
Purchases of reserves in place	8,681	—	8,681	15,512	—	15,512
Production	(24,877)	—	(24,877)	(11,978)	—	(11,978)
December 31, 2014	221,017	—	221,017	151,053	—	151,053
Proved developed reserves:						
December 31, 2012	229,539	4,664	234,203	52,552	6,018	58,570
December 31, 2013	106,976	—	106,976	38,929	—	38,929
December 31, 2014	149,697	—	149,697	65,482	—	65,482
Proved undeveloped reserves:						
December 31, 2012	194,134	—	194,134	62,519	—	62,519
December 31, 2013	80,981	—	80,981	62,590	—	62,590
December 31, 2014	71,320	—	71,320	85,571	—	85,571

Natural gas extensions and discoveries are primarily attributable to the following:

2014	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Marcellus and Eagle Ford.
2013	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Marcellus and Eagle Ford.
2012	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Barnett, Marcellus, and Eagle Ford.

Natural gas revisions of previous estimates are primarily attributable to the following:

2014	Positive price revisions in the U.S. primarily in the Marcellus.
2013	Positive price revisions in the U.S. primarily in the Marcellus.
2012	Negative price revisions in the U.S. primarily in the Barnett.

Natural gas purchases of reserves in place are primarily attributable to the following:

2014	Acquisition of proved developed and undeveloped reserves from Eagle Ford Minerals, LLC.

Natural gas sales of reserves in place are primarily attributable to the following:

2013	Sale of U.S. properties in the Barnett Shale to EnerVest during the fourth quarter and U.K. properties to Iona during the first quarter.
2012	Sales of properties to Atlas during the second quarter and sale of Gulf Coast properties during the third quarter.

Standardized Measure

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

	U.S.	U.K.	Worldwide
	(In thousands)		
2012			
Future cash inflows	$4,960,687	$623,678	$5,584,365
Future production costs	(1,009,850)	(87,727)	(1,097,577)
Future development costs	(982,101)	(11,194)	(993,295)
Future income taxes	(511,790)	(252,493)	(764,283)
Future net cash flows	2,456,946	272,264	2,729,210
Less 10% annual discount to reflect timing of cash flows	(1,277,463)	(33,352)	(1,310,815)
Standard measure of discounted future net cash flows	$1,179,483	$238,912	$1,418,395
2013			
Future cash inflows	$6,936,276	$—	$6,936,276
Future production costs	(1,629,663)	—	(1,629,663)
Future development costs	(1,340,722)	—	(1,340,722)
Future income taxes	(835,840)	—	(835,840)
Future net cash flows	3,130,051	—	3,130,051
Less 10% annual discount to reflect timing of cash flows	(1,508,640)	—	(1,508,640)
Standard measure of discounted future net cash flows	$1,621,411	$—	$1,621,411
2014			
Future cash inflows	$10,380,951	$—	$10,380,951
Future production costs	(2,532,106)	—	(2,532,106)
Future development costs	(1,680,795)	—	(1,680,795)
Future income taxes	(1,354,524)	—	(1,354,524)
Future net cash flows	4,813,526	—	4,813,526
Less 10% annual discount to reflect timing of cash flows	(2,258,444)	—	(2,258,444)
Standard measure of discounted future net cash flows	$2,555,082	$—	$2,555,082

Reserve estimates and future cash flows are based on the average realized prices for sales of oil and gas on the first calendar day of each month during the year. The average prices used for 2014, 2013 and 2012 were $92.24, $99.44, and $102.03 per barrel, respectively, for crude oil and condensate, $27.80, $25.60 and $32.12 per barrel, respectively, for natural gas liquids, and $3.24, $2.97 and $2.08 per Mcf, respectively, for natural gas.

Future operating expenses 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 oil and gas 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 oil and gas reserve estimates.

Changes in Standardized Measure

Changes in the standardized measure of discounted future net cash flows relating to proved oil and gas reserves are summarized below:

	U.S.	U.K.	Worldwide
	(In thousands)		
Standardized measure — January 1, 2012	$856,463	$184,573	$1,041,036
Revisions to reserves proved in prior years:			
Net change in sales prices and production costs related to future production	(55,249)	49,719	(5,530)
Net change in estimated future development costs	91,404	—	91,404
Net change due to revisions in quantity estimates	(77,919)	(46,803)	(124,722)
Accretion of discount	107,451	37,453	144,904
Changes in production rates (timing) and other	(3,369)	(6,061)	(9,430)
Total revisions	62,318	34,308	96,626
Net change due to extensions and discoveries, net of estimated future development and production costs	599,544	—	599,544
Net change due to sales of minerals in place	(212,910)	—	(212,910)
Sales of oil and gas produced, net of production costs	(313,354)	—	(313,354)
Previously estimated development costs incurred	202,187	32,760	234,947
Net change in income taxes	(14,765)	(12,729)	(27,494)
Net change in standardized measure of discounted future net cash flows	323,020	54,339	377,359
Standardized measure — December 31, 2012	$1,179,483	$238,912	$1,418,395
Revisions to reserves proved in prior years:			
Net change in sales prices and production costs related to future production	(232,361)	—	(232,361)
Net change in estimated future development costs	(10,602)	—	(10,602)
Net change due to revisions in quantity estimates	205,686	—	205,686
Accretion of discount	141,229	44,160	185,389
Changes in production rates (timing) and other	56,052	(44,160)	11,892
Total revisions	160,004	—	160,004
Net change due to extensions and discoveries, net of estimated future development and production costs	873,028	—	873,028
Net change due to sales of minerals in place	(191,155)	(441,597)	(632,752)
Sales of oil and gas produced, net of production costs	(444,841)	—	(444,841)
Previously estimated development costs incurred	217,395	—	217,395
Net change in income taxes	(172,503)	202,685	30,182
Net change in standardized measure of discounted future net cash flows	441,928	(238,912)	203,016
Standardized measure — December 31, 2013	$1,621,411	$—	$1,621,411
Revisions to reserves proved in prior years:			
Net change in sales prices and production costs related to future production	(240,533)	—	(240,533)
Net change in estimated future development costs	89,401	—	89,401
Net change due to revisions in quantity estimates	205,166	—	205,166
Accretion of discount	202,672	—	202,672
Changes in production rates (timing) and other	(61,099)	—	(61,099)
Total revisions	195,607	—	195,607
Net change due to extensions and discoveries, net of estimated future development and production costs	867,615	—	867,615
Net change due to purchases of minerals in place	352,867	—	352,867

Sales of oil and gas produced, net of production costs	(598,036)	—	(598,036)
Previously estimated development costs incurred	415,963	—	415,963
Net change in income taxes	(300,345)	—	(300,345)
Net change in standardized measure of discounted future net cash flows	933,671	—	933,671
Standardized measure — December 31, 2014	$2,555,082	$—	$2,555,082

18. Selected Quarterly Financial Data (Unaudited)

The following table presents selected quarterly financial data for the years ended December 31, 2014 and 2013:

2014	First	Second	Third	Fourth
	(In thousands, except per share amounts)			
Total revenues	$157,212	$193,475	$196,225	$163,275
Income from continuing operations	6,621	3,214	82,997	129,451
Net income	$5,976	$2,319	$83,789	$134,259
Net income per common share - basic				
Income from continuing operations	$0.15	$0.07	$1.83	$2.85
Net income per common share	$0.13	$0.05	$1.85	$2.96
Net income per common share - diluted				
Income from continuing operations	$0.14	$0.07	$1.80	$2.80
Net income per common share	$0.13	$0.05	$1.82	$2.91

2013	First	Second	Third	Fourth
	(In thousands, except per share amounts)			
Total revenues	$111,901	$134,224	$144,329	$129,728
Income (loss) from continuing operations	2,524	35,837	5,712	(22,215)
Net income (loss)	$26,182 (1)	$36,969	$4,521	($23,989) (2)
Net income (loss) per common share - basic				
Income (loss) from continuing operations	$0.06	$0.89	$0.14	($0.52) (2)
Net income (loss) per common share	$0.66 (1)	$0.92	$0.11	($0.56) (2)
Net income (loss) per common share - diluted				
Income (loss) from continuing operations	$0.06	$0.88	$0.14	($0.52) (2)
Net income (loss) per common share	$0.65 (1)	$0.91	$0.11	($0.56) (2)

1) First quarter 2013 results include the impact of pre-tax gain of $37.3 million related to the sale of the Company's U.K. North Sea assets which were reported as discontinued operations.

2) Fourth quarter 2013 results include the impact of a pre-tax loss of $45.4 million related to the sale of the Company's remaining oil and gas properties in the Barnett.

The sum of the quarterly net income (loss) per common share may not agree with the total year net income (loss) per common share as each quarterly computation is based on the net income (loss) for each period and the weighted average common shares outstanding during each 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 24, 2015

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 24, 2015
/s/ David L. Pitts David L. Pitts	Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2015
/s/ Gregory F. Conaway Gregory F. Conaway	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 24, 2015
/s/ Steven A. Webster Steven A. Webster	Chairman of the Board	February 24, 2015
/s/ Thomas L. Carter, Jr. Thomas L. Carter, Jr.	Director	February 24, 2015
/s/ Robert F. Fulton Robert F. Fulton	Director	February 24, 2015
/s/ F. Gardner Parker F. Gardner Parker	Director	February 24, 2015
/s/ Roger A. Ramsey Roger A. Ramsey	Director	February 24, 2015
/s/ Frank A. Wojtek Frank A. Wojtek	Director	February 24, 2015