Matador Resources Co
Form 10-K
March 02, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 001-34574
Matador Resources Company
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	27-4662601 (I.R.S. Employer Identification No.)
5400 LBJ Freeway, Suite 1500 Dallas, Texas 75240 (Address of principal executive offices)	75240 (Zip Code)

Registrant’s telephone number, including area code: (972) 371-5200

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ý No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ¨ No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, 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 ý 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. ý

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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ý		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 Exchange Act). Yes ¨ No ý

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant's most recently completed second fiscal quarter was $1,962,490,009.

As of February 27, 2015, there were 76,728,605 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Annual Report on Form 10-K, to the extent not set forth herein, is incorporated by reference to the registrant's definitive proxy statement relating to the 2015 Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

Table of Contents

MATADOR RESOURCES COMPANY
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2014
TABLE OF CONTENTS

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 10-K constitute “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “intend,” “may,” “might,” “potential,” “predict,” “project,” “should” or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: the integration of the assets, employees and operations of Harvey E. Yates Company following its merger with one of our wholly-owned subsidiaries on February 27, 2015, changes in oil or natural gas prices, the success of our drilling program, the timing of planned capital expenditures, sufficient cash flow from operations together with available borrowing capacity under our credit agreement, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, availability of acquisitions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this Annual Report on Form 10-K and in other documents that we file with or furnish to the U.S. Securities and Exchange Commission (the “SEC”), all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;
- our drilling of wells;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the merger of our wholly-owned subsidiary with Harvey E. Yates Company;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;
- estimated future reserves and the present value thereof; and
- our plans, objectives, expectations and intentions contained in this Annual Report on Form 10-K that are not historical.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such

Table of Contents

forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

Table of Contents

PART I

Item 1. Business.

In this Annual Report on Form 10-K, references to “we,” “our” or “the Company” refer to Matador Resources Company and its subsidiaries as a whole (unless the context indicates otherwise) and references to “Matador” refer solely to Matador Resources Company.

Unless the context otherwise requires, the term “common stock” refers to shares of our common stock after the conversion of our Class B common stock into Class A common stock upon the consummation of our initial public offering on February 7, 2012, as the Class A common stock then became the only class of common stock authorized, and the term “Class A common stock” refers to shares of our Class A common stock prior to the automatic conversion of our Class B common stock into Class A common stock upon the consummation of our initial public offering.

For certain oil and natural gas terms used in this Annual Report on Form 10-K, see the “Glossary of Oil and Natural Gas Terms” included in this Annual Report on Form 10-K.

General

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Eagle Ford shale play in South Texas and the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas. We also operate in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

We are a Texas corporation founded in July 2003 by Joseph Wm. Foran, Chairman and CEO. Mr. Foran began his career as an oil and natural gas independent in 1983 when he founded Foran Oil Company with $270,000 in contributed capital from 17 friends and family members. Foran Oil Company was later contributed to Matador Petroleum Corporation upon its formation by Mr. Foran in 1988. Mr. Foran served as Chairman and Chief Executive Officer of that company from its inception until it was sold in June 2003 to Tom Brown, Inc., in an all cash transaction for an enterprise value of approximately $388.5 million.

On February 2, 2012, our common stock began trading on the New York Stock Exchange (the “NYSE”) under the symbol “MTDR.” Prior to trading on the NYSE, there was no established public trading market for our common stock.

Our goal is to increase shareholder value by building oil and natural gas reserves, production and cash flows at an attractive rate of return on invested capital. We plan to achieve our goal by, among other items, executing the following business strategies:

- focus our exploration and development activities primarily on unconventional plays, including the Wolfcamp and Bone Spring plays in the Permian Basin, the Eagle Ford shale in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas;
- identify, evaluate and develop additional oil and natural gas plays as necessary to maintain a balanced portfolio of oil and natural gas properties;
- continue to improve operational and cost efficiencies;
- maintain our financial discipline; and
- pursue opportunistic acquisitions.

The successful execution of our business strategies in 2014 led to significant increases in our oil and natural gas revenues and Adjusted EBITDA, oil and natural gas production and proved oil and natural gas reserves, and the associated increase in the PV-10 of our proved oil and natural gas reserves. We also significantly increased our leasehold position in the Permian Basin and added to our acreage position in the Eagle Ford shale. Adjusted EBITDA and PV-10 are non-GAAP financial measures. For a definition of such terms and a reconciliation to the most directly comparable GAAP financial measures, see “Selected Financial Data — Non-GAAP Financial Measures” and “—Estimated Proved Reserves.”

3

Table of Contents

2014 Highlights

Increased Oil and Natural Gas Revenues and Adjusted EBITDA

Our oil and natural gas revenues for the year ended December 31, 2014 were the highest achieved in any fiscal year in the Company's history. Our oil and natural gas revenues increased $98.7 million to $367.7 million in 2014, which represents an increase of 37% from 2013. This revenue increase was primarily driven by a significant increase in our oil and natural gas production in 2014. Our Adjusted EBITDA of $262.9 million for 2014 was an increase of 37%, as compared to our Adjusted EBITDA of $191.8 million for 2013. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "Selected Financial Data — Non-GAAP Financial Measures."

Increased Oil, Natural Gas and Oil Equivalent Production

For the year ended December 31, 2014, we achieved record oil, natural gas and average daily oil equivalent production. In 2014, we produced 3.3 million barrels of oil, an increase of 56%, as compared to 2.1 million barrels of oil produced in 2013. We also produced 15.3 Bcf of natural gas, an increase of 18% from 12.9 Bcf of natural gas produced in 2013. Our average daily oil equivalent production for the year ended December 31, 2014 was 16,082 BOE per day, including 9,095 Bbl of oil per day and 41.9 MMcf of natural gas per day, an increase of 37%, as compared to 11,740 BOE per day, including 5,843 Bbl of oil per day and 35.4 MMcf of natural gas per day, for the year ended December 31, 2013. The increase in oil production was primarily attributable to our ongoing development activities in the Eagle Ford shale, as well as better-than-expected initial production contributions from wells drilled in the Permian Basin during 2014. We achieved this increased oil production despite having as much as 15% to 20% of our production capacity shut in at various times during 2014 while offsetting wells were being drilled and completed and pipeline connections were being made. The increase in natural gas production was primarily attributable to initial production contributions from wells drilled in the Permian Basin, as well as non-operated Haynesville shale wells drilled on our Elm Grove properties in Northwest Louisiana. Oil production comprised 57% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the year ended December 31, 2014, as compared to 50% for the year ended December 31, 2013 and 37% for the year ended December 31, 2012.

Increased Oil and Natural Gas Reserves

At December 31, 2014, our estimated total proved oil and natural gas reserves were 68.7 million BOE, including 24.2 million Bbl of oil and 267.1 Bcf of natural gas, which is an increase of 33% from December 31, 2013. The associated PV-10 of our estimated total proved oil and natural gas reserves increased 59% to $1.04 billion at December 31, 2014 from $655.2 million at December 31, 2013. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "—Estimated Proved Reserves."

Our proved oil reserves grew 48% to 24.2 million Bbl at December 31, 2014 from 16.4 million Bbl at December 31, 2013. This growth in oil reserves was primarily attributable to our drilling programs in both the Eagle Ford shale and the Permian Basin during 2014. Our proved natural gas reserves increased 26% to 267.1 Bcf at December 31, 2014 from 212.2 Bcf at December 31, 2013. This increase in proved natural gas reserves was primarily attributable to our operated drilling activity in the Permian Basin and non-operated drilling activity in the Haynesville shale during 2014. At December 31, 2014, proved developed reserves included 14.1 million Bbl of oil and 102.8 Bcf of natural gas, and proved undeveloped reserves included 10.1 million Bbl of oil and 164.3 Bcf of natural gas. Proved developed reserves comprised 45% and proved oil reserves comprised 35% of our total proved oil and natural gas reserves, respectively, at December 31, 2014. Proved developed reserves comprised 33% of our total reserves and proved oil reserves comprised 32% of our total proved oil and natural gas reserves, respectively, at December 31, 2013.

Operational Highlights

We focus on optimizing the development of our resource base by seeking ways to maximize our recovery per well relative to the cost incurred and to minimize our operating costs per BOE produced. We apply an analytical approach to track and monitor the effectiveness of our drilling and completion techniques and service providers. This allows us to manage more effectively operating costs, the pace of development activities, technical applications, the gathering and marketing of our production and capital allocation. Additionally, we concentrate on our core areas, which allows us to achieve economies of scale and reduce operating costs. Largely as a result of these factors, we believe that we have increased our technical knowledge of drilling, completing and producing Eagle Ford shale wells, particularly over the past three years, and, during 2014, we began to apply what we learned from the Eagle Ford shale, as well as from our Haynesville shale experience, to the delineation and development of our Permian Basin acreage.

We continued our strong execution in the Eagle Ford shale during 2014, and the Eagle Ford continued to drive our production and revenue growth in 2014. During 2014, 65% of our total daily oil equivalent production, or 10,501 BOE per day, consisting of 7,764 Bbl of oil per day and 16.4 MMcf of natural gas per day, was produced from the Eagle Ford shale.

Table of Contents

Over the past three years, we have progressed from drilling Eagle Ford wells on single-well pads to multi-well pad drilling, and most recently, to multi-well batch drilling. In 2014, approximately 90% of our Eagle Ford wells were drilled in multi-well batch mode using drilling rigs equipped with a “walking” package, and as a result, we continued to improve both drilling times and costs. Recent wells drilled on our western Eagle Ford acreage in La Salle County, Texas had drilling times from spud to total depth of seven to 10 days per well. Average drilling and completions costs in this area have been reduced to $5.5 to $6.5 million per well. On our central Eagle Ford acreage in Karnes County, Texas, significant drilling improvements, including the use of the “walking” rig, were made during 2014 that reduced drilling times by several days, especially during the second half of 2014. We anticipate that the combination of further operational improvements and service cost reductions may yield drilling and completion costs at or below $6.0 million on wells drilled on our central Eagle Ford acreage during 2015.

During 2014, we made further improvements to our Eagle Ford fracture treatment design, with the goal of developing a treatment design specific to wells developed on 40- to 50-acre spacing. The treatments were designed to create higher fracture conductivity closer to the wellbore, more consistent fracture geometry and more overall fractures. We believe that we achieved these design objectives by (1) increasing the fluid volumes pumped to 40 Bbl per foot and the total proppant volumes pumped to 2,000 pounds per foot of completed lateral length or more, (2) tightening the perforation cluster spacing and (3) further modifying the perforation geometry. These “Generation 7” fracture treatments are typically resulting in significant improvements in initial well productivity and overall well performance for our Eagle Ford wells as compared to earlier generation fracture treatment designs using less fluid and proppant and different perforation and cluster geometries. We also believe that initiating the use of gas lift early in the life of our newly drilled Eagle Ford wells has accelerated oil production, reduced lease operating expenses, lowered maintenance costs and helped our wells recover faster after being shut in for offset well operations. In addition, as our development program matured in 2014, most of our newly completed Eagle Ford wells were able to use existing tank batteries and facilities, resulting in significant cost savings as compared to the need to construct new facilities in previous years.

We substantially increased our acreage position in the Permian Basin during 2014, and at December 31, 2014, we held approximately 92,700 gross (66,100 net) acres primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. We also continued the exploration and delineation of our Permian Basin acreage, operating one to two drilling rigs on our acreage there in 2014 and testing six different Bone Spring and Wolfcamp target intervals. The initial performance of most of the wells we have drilled and completed thus far in our three main prospect areas—the Wolf prospect area in Loving County, Texas, the Ranger prospect area in Lea County, New Mexico and the Rustler Breaks prospect area in Eddy County, New Mexico—have exceeded our expectations. As a result, our Permian Basin properties are becoming an increasingly important component of our asset portfolio, and the Permian Basin will be our primary area of focus in 2015. Our average daily oil equivalent production from the Permian Basin grew 10-fold from 260 BOE per day in the fourth quarter of 2013 to 2,600 BOE per day in the fourth quarter of 2014, comprising 11% of our total oil equivalent production for all of 2014. We expect our Permian Basin production to increase throughout 2015 as we continue the delineation and development of these properties.

We did not drill any operated Haynesville shale wells during 2014, but we did participate in a number of non-operated wells drilled in the Haynesville shale in Northwest Louisiana. The most impactful were the Haynesville wells drilled and completed by a subsidiary of Chesapeake Energy Corporation (“Chesapeake”) on our Elm Grove properties in southern Caddo Parish. In 2014, Chesapeake completed and placed on production 14 gross wells, comprising 3.3 wells net to Matador’s working interest. These wells had initial production rates ranging from 8 to 14 MMcf of natural gas per day (gross) and estimated ultimate recoveries of 8 to 12 Bcf per well. As these wells were placed on production in 2014, our Haynesville natural gas production grew more than three-fold from 11.1 MMcf per day in the fourth quarter of 2013 to approximately 35.0 MMcf per day in the fourth quarter of 2014. In January 2015, Chesapeake completed and placed on production an additional three gross (0.5 net) wells at Elm Grove. As a result, our Haynesville natural gas production grew to over 50 MMcf of natural gas per day as of February 27, 2015.

Acreage Acquisitions

During 2014, we acquired approximately 29,300 gross (21,800 net) additional acres in the Permian Basin in Southeast New Mexico and West Texas. These acreage acquisitions brought our total Permian Basin acreage position to approximately 92,700 gross (66,100 net) acres as of December 31, 2014. Between January 1 and December 31, 2014, we also acquired approximately 3,200 gross (3,000 net) acres in the Eagle Ford shale play in South Texas.

As noted below in “— Recent Developments”, in January 2015, we entered into a definitive agreement pursuant to which one of our wholly-owned subsidiaries would merge with Harvey E. Yates Company (“HEYCO”), a subsidiary of HEYCO Energy Group, Inc., combining certain oil and natural gas producing properties and undeveloped acreage located in Lea and Eddy Counties, New Mexico owned by HEYCO with our Delaware Basin operations (the “HEYCO Merger”). The HEYCO Merger included approximately 58,600 gross (18,200 net) acres. Upon the closing of the HEYCO Merger on February 27, 2015, our Permian Basin acreage position increased to approximately 152,400 gross (85,400 net) acres.

Table of Contents

Issuance of Common Stock

On May 29, 2014, we completed a public offering of 7,500,000 shares of our common stock. After deducting direct offering costs totaling approximately $0.6 million, we received net proceeds of approximately $181.3 million. We used a portion of the net proceeds to repay $180.0 million in outstanding borrowings under our third amended and restated credit agreement (the “Credit Agreement”), which amounts were subsequently reborrowed in accordance with the terms of that facility. The remaining $1.3 million of the offering net proceeds was used to fund working capital requirements.

Recent Developments

On January 19, 2015, we entered into a definitive agreement pursuant to which one of our wholly-owned subsidiaries would merge with HEYCO, combining certain oil and natural gas producing properties and undeveloped acreage located in Lea and Eddy Counties, New Mexico owned by HEYCO with our Delaware Basin operations. The HEYCO Merger closed on February 27, 2015. As consideration for the HEYCO Merger, we paid approximately $21.6 million in cash, assumed debt obligations of approximately $12.0 million and issued 3,300,000 shares of the Company’s common stock and 150,000 shares of a new series of the Company’s convertible preferred stock to HEYCO Energy Group, Inc. In addition, we paid an additional $3.0 million for customary purchase price adjustments, including adjusting for production, revenues and operating and capital expenditures from September 1, 2014 to closing. Pursuant to the terms of the merger agreement, 125,000 of the 150,000 shares of Series A Preferred Stock (as defined below) issued upon the closing of the HEYCO Merger were placed into escrow to satisfy post-closing adjustments to the merger consideration for any title or environmental defects on the assets we added.

As part of the consideration for the acquisition, we issued 150,000 shares of Series A Convertible Preferred Stock (the “Series A Preferred Stock”). Each share of Series A Preferred Stock is entitled to ten votes on each matter submitted to our shareholders for vote. The holders of Series A Preferred Stock will vote, on an as-converted basis, together with the holders of common stock as a single class, except with respect to matters that would adversely affect the holders of Series A Preferred Stock as compared to the holders of common stock, in which case the holders of Series A Preferred Stock will vote as a separate class. Beginning on August 27, 2015 and until such time as the Series A Preferred Stock is converted to common stock, the holders will be entitled to a quarterly dividend of $1.80 per share. The private placement of the Series A Preferred Stock and the common stock issued in connection with the HEYCO Merger was made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereof.

Each share of Series A Preferred Stock will automatically convert into ten shares of our common stock, subject to customary anti-dilution adjustments, upon the vote and approval by our shareholders of an amendment to our Amended and Restated Certificate of Formation to increase the number of shares of authorized common stock (the “Charter Amendment”). On February 25, 2015, we filed a definitive proxy statement with the Securities and Exchange Commission and began mailing to our shareholders such proxy materials related to a special meeting of shareholders to be held on April 2, 2015 at 9:30 a.m., Central Time, for the purpose of approving the Charter Amendment. All shareholders of record as of the close of business on February 18, 2015 will be entitled to vote at the special meeting.

As part of the merger consideration, one of our wholly-owned subsidiaries, MRC Delaware Resources, LLC (“MRC Delaware”), assumed approximately $12.0 million of HEYCO’s indebtedness (the “Assumed Indebtedness”). Such Assumed Indebtedness is evidenced by a loan agreement and a promissory note executed by MRC Delaware in favor of PlainsCapital Bank (“PlainsCapital”) in the principal amount of $12,500,000. Outstanding borrowings are secured by mortgages on substantially all of the oil and natural gas properties held by MRC Delaware after the HEYCO Merger and are subject to a borrowing base of approximately $12.0 million. The principal and interest under the promissory note are due and payable on July 24, 2015 and outstanding borrowings under the promissory note bear interest at a variable annual rate equal to the prime rate, but in no event less than 3.25%. The Company executed a guaranty (the “Guaranty”) pursuant to which the Company has agreed to guarantee MRC Delaware’s prompt, complete and full payment of the principal and interest and other fees and obligations relating to the Assumed Indebtedness. In addition, the Company has agreed to comply with a provision of the loan agreement governing the Assumed Indebtedness that sets forth a funded debt to EBITDA (defined as net income before interest, taxes, depletion, depreciation, intangible drilling costs and amortization) ratio covenant, which is defined as total funded debt outstanding for the Company and its consolidated subsidiaries divided by a rolling four quarter EBITDA calculation for the Company and its consolidated subsidiaries, of 4.25 or less. A failure by the Company to meet the requirements of such covenant, or a failure to otherwise comply with the payment guaranty provisions set forth in the Guaranty, will constitute an event of default under our Credit Agreement.

In connection with the HEYCO Merger, we entered into a registration rights agreement with HEYCO Energy Group, Inc., pursuant to which we will be required, upon request from HEYCO Energy Group, Inc. at any time on or after February 27, 2016, to file and maintain a shelf registration statement with respect to the resale of the shares of common stock issued as consideration for the HEYCO Merger and upon conversion of the Series A Preferred Stock, respectively, and to provide piggyback registration rights for such shares of common stock.

Table of Contents

As noted above, the HEYCO Merger added approximately 58,600 gross (18,200 net) acres in the Delaware Basin in Lea and Eddy Counties, New Mexico, strategically located between our existing acreage in the Ranger and Rustler Breaks prospect areas. Over 95% of the HEYCO acreage position consists of state and federal leases, most with favorable net revenue interests greater than 80% and some as high as 87.5%. Essentially all of the acreage is held by production from existing wells and production units.

Principal Areas of Interest

Our focus since inception has been the exploration for oil and natural gas in unconventional plays with an emphasis in recent years on the Eagle Ford shale play in South Texas, the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas and the Haynesville shale play in Northwest Louisiana. During 2014, we devoted most of our efforts and most of our capital investment to our drilling operations in the Eagle Ford shale in South Texas and the Wolfcamp and Bone Spring plays in the Permian Basin as we sought to continue to increase our oil production and reserves. Since our inception, our exploration efforts have concentrated primarily on known hydrocarbon-producing basins with well-established production histories offering the potential for multiple-zone completions. We have also sought to balance the risk profile of our prospects by exploring for more conventional targets as well, although at December 31, 2014, essentially all of our efforts were focused on unconventional plays.

At December 31, 2014, our principal areas of interest consisted of the Eagle Ford shale play in South Texas, the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas, and the Haynesville shale play, as well as the traditional Cotton Valley and Hosston (Travis Peak) formations, in Northwest Louisiana and East Texas. We also have a large exploratory leasehold position in Southwest Wyoming and adjacent areas of Utah and Idaho where we are testing the Meade Peak shale.

The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2014:

	Gross Acreage	Net Acreage	Producing Wells Gross	Producing Wells Net	Total Identified Drilling Locations (1) Gross	Total Identified Drilling Locations (1) Net	Estimated Net Proved Reserves (2) MBOE (3)	Estimated Net Proved Reserves (2) % Developed	Avg. Daily Production (BOE/d) (3)
South Texas:									
Eagle Ford (4)	39,871	29,686	117	99.2	278	240.4	22,257	71.8	10,501
NW Louisiana/E Texas:									
Haynesville	21,295	13,571	183	16.8	471	111.9	32,183	30.0	3,290
Cotton Valley (5)	22,362	19,748	97	62.4	71	50.1	1,223	100.0	501
Area Total (6)	27,251	24,396	280	79.2	542	162.0	33,406	32.6	3,791
Permian Basin:									
SE New Mexico, West Texas (7)	92,682	66,076	31	19.2	1,445	959.5	13,030	33.1	1,790
Other:									
Wyoming, Utah, Idaho	75,674	35,732	—	—	—	—	—	—	—
Total	235,478	155,890	428	197.6	2,265	1,361.9	68,693	45.4	16,082

(1) Identified and engineered drilling locations. These locations have been identified for potential future drilling and were not producing at December 31, 2014. The total net engineered drilling locations is calculated by multiplying the gross engineered drilling locations in an operating area by our working interest participation in such locations. At December 31, 2014, these engineered drilling locations included 40 gross (32.6 net) locations to which we have assigned proved undeveloped reserves in the Eagle Ford, 19 gross (15.6 net) locations to which we have assigned proved undeveloped reserves in the Wolfcamp or Bone Spring plays in the Permian Basin and 127 gross (20.6 net) locations to which we have assigned proved undeveloped reserves in the Haynesville. We had no proved

undeveloped reserves assigned to engineered drilling locations in any other formation at December 31, 2014.

(2) These estimates were prepared by our engineering staff and audited by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

(3) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Includes two wells producing small quantities of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(5) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(6) Some of the same leases cover the net acres shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the net acreage for both formations is not equal to the total net acreage for Northwest Louisiana and East Texas. This total includes acreage that we are producing from or that we believe to be prospective for these formations.

(7) Includes potential future engineered drilling locations in the Wolfcamp, Bone Spring, Delaware and Avalon plays on our acreage in the Permian Basin at December 31, 2014.

Table of Contents

We are active both as an operator and as a co-working interest owner with larger industry participants, including affiliates of EOG Resources, Inc., Royal Dutch Shell plc, Chesapeake Energy Corporation, EP Energy Company, Concho Resources Inc., Devon Energy Corporation, BHP Billiton and others. At December 31, 2014, we were the operator for over 90% of our Eagle Ford acreage and approximately two-thirds of our Haynesville acreage, including approximately 36% of our acreage in what we believe is the core area of the Haynesville play. A large portion of our acreage in the core area of the Haynesville shale is operated by Chesapeake. At December 31, 2014, we also operated the majority of our acreage in the Permian Basin in Southeast New Mexico and West Texas, as well as all of our acreage in Southwest Wyoming and the adjacent areas of Utah and Idaho. In those wells where we are not the operator, our working interests are often relatively small, particularly in the Haynesville shale.

While we do not always have direct access to our operating partners' drilling plans with respect to future well locations on non-operated properties, we do attempt to maintain ongoing communications with the technical staff of these operators in an effort to understand their drilling plans for purposes of our capital expenditure budget and our booking of any related proved undeveloped well locations and reserves. We review these locations with Netherland, Sewell & Associates, Inc., independent reservoir engineers, on a periodic basis to ensure their concurrence with our estimates of these drilling plans and our approach to booking these reserves.

South Texas — Eagle Ford Shale and Other Formations

The Eagle Ford shale extends across portions of South Texas from the Mexican border into East Texas forming a band roughly 50 to 100 miles wide and 400 miles long. The Eagle Ford is an organically rich calcareous shale and lies between the deeper Buda limestone and the shallower Austin Chalk formation. Along the entire length of the Eagle Ford trend, the structural dip of the formation is consistently down to the south with relatively few, modestly sized structural perturbations. As a result, depth of burial increases consistently southwards along with the thermal maturity of the formation. Where the Eagle Ford is shallow, it is less thermally mature and therefore more oil prone, and as it gets deeper and becomes more thermally mature, the Eagle Ford is more natural gas prone. The transition between being more oil prone and more natural gas prone includes an interval that typically produces liquids-rich natural gas with condensate.

At December 31, 2014, our properties included approximately 39,900 gross (29,700 net) acres in the Eagle Ford shale play in Atascosa, DeWitt, Gonzales, Karnes, La Salle, Wilson and Zavala Counties in South Texas. We believe that approximately 88% of our Eagle Ford acreage is prospective predominantly for oil or liquids-rich natural gas with condensate. In addition, we believe that portions of this acreage may also be prospective for other targets, such as the Austin Chalk, Buda, Edwards and Pearsall formations, from which we would expect to produce predominantly oil and liquids. Approximately 77% of our Eagle Ford acreage was held by production at December 31, 2014, and approximately 96% of our Eagle Ford acreage was either held by production at December 31, 2014 or not burdened by lease expirations before 2016. During the year ended December 31, 2014, we acquired approximately 3,200 gross (3,000 net) acres in the Eagle Ford shale play that we consider to be prospective primarily for oil production. This acreage more than replaced the acreage upon which we drilled and established oil and natural gas production and reserves in the Eagle Ford during 2014.

At December 31, 2014, we had 117 gross (99.2 net) wells producing from the Eagle Ford shale in South Texas. We had drilled and completed a total of 97 gross (93.2 net) Eagle Ford wells on our operated properties, and we had also participated in 20 gross (6.0 net) Eagle Ford wells with co-working interest owners on certain of our non-operated Eagle Ford properties. During 2014, approximately 56% of our total capital expenditures of $610.4 million were directed to our operations in the Eagle Ford shale, as we continued executing our strategy to significantly increase our oil production and oil reserves. As a result of both lower oil and natural gas prices in early 2015 and the fact that, at December 31, 2014, approximately 96% of our Eagle Ford acreage was either held by production or not burdened by lease expirations before 2016, we plan to temporarily suspend our Eagle Ford development program after the first quarter of 2015. We expect to run two operated drilling rigs in the Eagle Ford during the first quarter of 2015, but then do not plan to drill any operated wells in the Eagle Ford for the remainder of the year. We have allocated approximately $90.0 million, or 26%, of our 2015 capital expenditures budget of $350.0 million (excluding capital expenditures associated with the HEYCO Merger) to our anticipated drilling and completion activities in the Eagle

Ford, as well as for the acquisition of additional leasehold interests in this area.
During the year ended December 31, 2014, we completed and began producing oil and natural gas from 44 gross (36.7 net) Eagle Ford shale wells drilled on our acreage position in South Texas, including 36 gross (34.5 net) operated and eight gross (2.2 net) non-operated wells. As we completed and began producing oil and natural gas from these wells during 2014, our Eagle Ford production increased significantly. For the year ended December 31, 2014, 65% of our total daily oil equivalent production, or 10,501 BOE per day, including 7,764 Bbl of oil per day and 16.4 MMcf of natural gas per day, was produced from the Eagle Ford shale. The vast majority of our oil production in 2014 and 2013 was attributable to the Eagle Ford shale. The Eagle Ford shale contributed approximately 85% of our daily oil production and approximately 39% of our daily natural gas production during 2014, as compared to approximately 98% of our daily oil production and approximately 42% of our daily natural gas production during 2013. During the year ended December 31, 2013, approximately 70% of our daily oil equivalent production, or 8,225 BOE per day, including 5,748 Bbl of oil per day and 14.9 MMcf of natural gas per day, was

attributable to the Eagle Ford shale. During the year ended December 31, 2012, only about 8% of our daily oil equivalent production, or 548 BOE per day, including 331 Bbl of oil per day and 1.3 MMcf of natural gas per day, was attributable to the Eagle Ford shale. This growth in oil and natural gas production from the Eagle Ford shale over the past several years reflects our ongoing drilling and completion operations in South Texas. Natural gas produced from most of our Eagle Ford shale wells is a liquids-rich natural gas and our purchasers process this natural gas for us at their processing facilities to remove the natural gas liquids, such as ethane, propane and other heavier natural gas liquids components. Our Eagle Ford wells typically yield five to seven gallons of natural gas liquids per Mcf of natural gas produced at the wellhead depending on the specific property.

At December 31, 2014, approximately 32% of our estimated total proved oil and natural gas reserves, or 22.3 million BOE, was attributable to the Eagle Ford shale, including approximately 16.1 million Bbl of oil and 36.9 Bcf of natural gas. Our total proved reserves attributable to the Eagle Ford shale increased approximately 10% to 22.3 million BOE for the year ended December 31, 2014, as compared to 20.2 million BOE for the year ended December 31, 2013. As a result of our drilling and completions schedule in 2014, and particularly our drilling of infill wells on 40- to 50-acre spacing, many of the Eagle Ford wells we drilled during 2014 were identified as proved developed non-producing ("PDNP") or proved undeveloped ("PUD") reserves at December 31, 2013. Our Eagle Ford total proved reserves at December 31, 2014 comprised approximately 67% of our proved oil reserves and 14% of our proved natural gas reserves, as compared to approximately 93% of our proved oil reserves and 14% of our proved natural gas reserves at December 31, 2013. The PV-10 of our total proved reserves in the Eagle Ford shale was $603.8 million, or approximately 58% of the PV-10 of our total proved reserves of $1.04 billion at December 31, 2014. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "— Estimated Proved Reserves."

At December 31, 2014, we have identified 278 gross (240.4 net) engineered locations for potential future drilling on our Eagle Ford acreage. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Eagle Ford wells and other nearby wells based on available public data, drilling densities anticipated on our properties and observed on properties of other operators, estimated horizontal lateral lengths, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other factors. The identified well locations presume that we will be able to develop our Eagle Ford properties on 40- to 80-acre spacing, depending on the specific property and the wells we have already drilled. As a result of the development wells we drilled during 2014, we anticipate the Eagle Ford wells to be drilled on our acreage in central and northern La Salle, northern Karnes and southern Wilson Counties can be developed on 40- to 50-acre spacing, while other properties, particularly the eastern portion of our acreage in DeWitt County, are more likely to be developed on 80-acre spacing. While there are some locations that we would choose not to drill with oil prices near $50 per Bbl as they have been in early 2015, almost all of these locations are associated with portions of our acreage that are already held by production at December 31, 2014 or not burdened by near-term lease expirations. As a result, these engineered drilling locations remain available to be developed by us at a future time when commodity prices improve, drilling and completion costs decline further or new technologies are developed that increase the expected recoveries. At December 31, 2014, these 278 gross (240.4 net) identified drilling locations included only 40 gross (32.6 net) locations to which we have assigned proved undeveloped reserves.

We believe that we have increased our technical knowledge of drilling, completing and producing Eagle Ford shale wells, particularly over the past three years. During this time, we have progressed from drilling wells on single-well pads to multi-well pad drilling, and most recently, to multi-well batch drilling. In August 2013, we began drilling certain wells on our western Eagle Ford acreage in La Salle County, Texas from batch-drilled pads using a drilling rig equipped with a "walking" package, and in April 2014, we began using a "walking" rig on our central Eagle Ford acreage in Karnes and Wilson Counties. As a result, we have improved drilling times and costs in both areas. We have realized drilling cost savings on wells drilled from batch-drilled pads of approximately 20% per foot drilled compared to wells drilled from single-well pads and approximately 10% per foot drilled compared to wells drilled from multi-well pads. As a result of batch mode development and other operational improvements, we estimate that we have saved approximately $600,000 per well on drilling costs, as compared to wells drilled from single-well pads. Our development strategy in 2014 used three wells per batch pad, but the majority of our Eagle Ford wells, which will be drilled in the first quarter of 2015, will be developed with four wells per batch pad. We expect this development approach to yield further incremental cost savings.

During 2014, most wells drilled on our western Eagle Ford acreage in La Salle County, Texas had drilling times from spud to total depth of seven to 10 days per well. Average drilling and completions costs in this area have been reduced to $5.5 to $6.5 million per well. On our central Eagle Ford acreage in Karnes County, Texas, significant drilling improvements, including the use of the “walking” rig, made during 2014 also reduced drilling times by several days, especially during the second half of 2014. We anticipate that the combination of further operational improvements and service cost reductions may yield drilling and completion costs at or below $6.0 million on wells drilled and completed in our central Eagle Ford acreage during 2015.

During 2014, we also made further improvements to our Eagle Ford fracture treatment design, with the goal of developing a treatment design specific to wells developed on 40- to 50-acre spacing. The treatments were designed to create higher fracture conductivity closer to the wellbore, more consistent fracture geometry and more overall fractures. We believe that we achieved these design objectives by (1) increasing the fluid volumes pumped to 40 Bbl per foot and the total proppant volumes pumped to 2,000 pounds per foot of completed lateral length or more, (2) tightening the perforation cluster spacing and (3) further modifying the perforation geometry. These “Generation 7” fracture treatments are typically resulting in significant improvements in initial well productivity and overall well performance as compared to earlier generation fracture treatment designs using less fluid and proppant and different perforation and cluster geometries. We also believe that initiating the use of gas lift early in the life of our newly drilled Eagle Ford wells has accelerated oil production, reduced lease operating expenses, lowered maintenance costs and helped our wells recover faster after being shut in for offset well operations. In addition, as our development program matured in 2014, most of our newly completed Eagle Ford wells were able to use existing tank batteries and facilities, resulting in significant cost savings as compared to the need to construct new facilities in previous years.
We believe portions of our Eagle Ford acreage may also be prospective for the Austin Chalk, Buda, Edwards and Pearsall formations, from which we would expect to produce predominantly oil and liquids. In particular, we own approximately 8,900 gross (8,900 net) contiguous acres on our Glasscock Ranch property in southeast Zavala County, Texas which are held by production and which we believe may be prospective for the Buda formation. We believe our acreage is located within the extension of a trend where encouraging drilling by other operators has occurred in the Buda just southwest of our leasehold position. We have acquired a 3-D seismic survey over our acreage, and at February 27, 2015, we were evaluating a series of seismic attributes that are similar to fracture patterns observed in cores from other wells in the area and from our drilling of previous wells on the acreage in 2012 and which are consistent with regional mapping. At December 31, 2014, we had not drilled any Buda wells nor had we included any Buda locations in our future drilling locations.

Southeast New Mexico and West Texas — Permian Basin

The Permian Basin in Southeast New Mexico and West Texas is a mature exploration and production province with extensive developments in a wide variety of petroleum systems resulting in stacked target horizons in many areas. Historically, the majority of development in this basin has focused on relatively conventional reservoir targets, but the combination of advanced formation evaluation, 3-D seismic technology, horizontal drilling and hydraulic fracturing technology is enhancing the development potential of this basin, particularly in the organic rich shales, or source rocks, of the Wolfcamp and in the low permeability sand and carbonate reservoirs of the Bone Spring, Avalon and Delaware formations. We believe these formations, which have been typically considered to be low quality rocks because of their low permeability, are strong candidates for horizontal drilling and intense hydraulic fracturing techniques.

In the western part of the Permian Basin (also known as the Delaware Basin), the Lower Permian age Bone Spring (also called the Leonardian) and Wolfcamp formations are several thousand feet thick and contain stacked layers of shales, sandstones, limestones and dolomites. These intervals represent a complex and dynamic submarine depositional system that also includes organic rich shales that are proven to be the source rocks for oil and natural gas produced in the basin. Historically, production has come from the “conventional” reservoirs; however, we and other industry players have realized that the source rocks also have sufficient porosity and permeability to be commercial reservoirs. In addition, the source rocks are interbedded with reservoir layers that have filled with hydrocarbons, both of which can produce significant volumes of oil and natural gas when connected by horizontal wellbores with multi-interval hydraulic fracture treatments. Particularly in the Delaware Basin, there are multiple horizontal targets in a given area that exist within the several thousand feet of hydrocarbon bearing layers that make up the Bone Spring and Wolfcamp plays. Multiple horizontal drilling and completion targets are being identified and targeted by companies, including us, throughout the vertical section including the Delaware, Avalon, Bone Spring (First, Second and Third Sand) and several intervals within the Wolfcamp shale, often identified as Wolfcamp “A” through “D”.
During 2014, we acquired an additional 29,300 gross (21,800 net) acres in Southeast New Mexico and West Texas, and at December 31, 2014, our leasehold position in the Permian Basin included approximately 92,700 gross (66,100

net) acres, primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. With the closing of the HEYCO Merger on February 27, 2015, our Permian Basin acreage position increased to approximately 152,400 gross (85,400 net) acres. We consider the vast majority of our Permian Basin acreage position to be prospective for oil and liquids-rich targets in the Bone Spring and Wolfcamp formations. Other potential targets on certain portions of our acreage include the Avalon shale and Delaware formations, as well as the Abo, Strawn, Devonian, Penn Shale, Atoka and Morrow formations.

During the year ended December 31, 2014, we continued the exploration and delineation of our Permian Basin acreage. We completed and began producing oil and natural gas from 11 gross (9.6 net) wells in the Permian Basin, including ten gross (9.5 net) operated wells and one gross (0.1 net) non-operated wells. The ten operated wells tested six different Bone Spring and Wolfcamp intervals. We completed and placed on production five wells in the Wolf prospect area in Loving County, Texas — four wells testing the Wolfcamp “X” sand at the top of the Wolfcamp interval and one well testing the Wolfcamp “A” interval below the “X/Y” sands. Four operated wells in the Ranger prospect area in Lea County, New Mexico tested the Second Bone Spring, the Wolfcamp “D” and the Third Bone Spring. One operated well in the Rustler Breaks prospect area in Eddy County, New Mexico tested the Wolfcamp “B” interval.

In the Wolf prospect area in Loving County, Texas, the upper Wolfcamp “X” sand has proven to be highly productive, and the initial wells completed in this prospect continue to perform above our original projections. As of early February 2015, the Dorothy White #1H well, our first well in the Wolf prospect area, had produced 310,000 BOE (66% oil), including 203,000 Bbl of oil and 640 MMcf of natural gas, in just over one year of production and was still producing 450 Bbl of oil and 1.7 MMcf of natural gas per day. Other wells we have drilled near the Dorothy White #1H are similar. As of early February 2015, the Norton Schaub #1H had produced 122,000 BOE (69% oil) in approximately six months of production, including 84,000 Bbl of oil and 228 MMcf of natural gas, and was still producing 500 Bbl of oil per day and 1.6 MMcf of natural gas per day. The Johnson 44-02S-B53 #204H well drilled north of the Dorothy White #1H had produced 117,000 BOE (65% oil), including 75,000 Bbl of oil and 248 MMcf of natural gas, in just four months of production and in early February 2015 was producing 530 Bbl of oil per day and 1.8 MMcf of natural gas per day. By comparison, the Dorothy White #1H produced 110,000 BOE in its first four months of production. At the southern end of the Wolf prospect area, the Arno #1H well was also drilled and completed in the Wolfcamp “X” sand. This well tested 1,110 BOE per day (27% oil), including 300 Bbl of oil and 4.9 MMcf of natural gas per day at a flowing pressure of 4,100 pounds per square inch (“psi”) on a 26/64-inch choke. This well has only recently been placed on production after having been shut in awaiting a pipeline connection and the repair of a county road that was washed out during flooding in this area in late September 2014. In late December 2014, we also tested the Norton Schaub 84-TTT-B33 WF #2010H in the Wolf prospect area. During a 24-hour initial potential test, this well flowed 875 BOE per day (69% oil), including 608 Bbl of oil per day and 1.6 MMcf of natural gas per day at 2,600 psi on a 28/64-inch choke. The Norton Schaub 84-TTT-B33 WF #2010H was our first test of the Wolfcamp “A” interval, a more organically rich portion of the upper Wolfcamp below the “X/Y” sands. This was another encouraging test of a new Wolfcamp bench and indicates the Wolfcamp “A” may be another potential completion target in the upper Wolfcamp.

In the Ranger prospect area in Lea County, New Mexico, our first two Second Bone Spring completions have performed above our original projections for this area. As of early February 2015, the Ranger 33 State Com #1H had produced 184,000 BOE (91% oil) in its first 15 months of production and was still producing almost 200 Bbl of oil per day with gas-lift assist. The Pickard State 20-18-24 #1H, also drilled and completed in the Second Bone Spring, had produced 71,000 BOE (92% oil) in its first six months of production and was producing 330 Bbl of oil per day with gas-lift assist in early February 2015. We installed gas-lift assist on the Ranger 33 State Com #1H well within its first two months of production, and given the early success of the gas-lift assist on that well, the Pickard State 20-18-34 #1H well was also equipped with gas-lift assist within approximately 30 days of being placed on production. The use of gas-lift assist on these wells in the Ranger prospect area is just one example of a transfer of technology and lessons learned from our Eagle Ford development program in South Texas to the Permian Basin.

Also in the Ranger prospect area, we drilled and completed the Pickard State 20-18-34 #2H during 2014. This well was completed in the Wolfcamp “D” bench at approximately 12,000 feet true vertical depth, and we believe it to be the northernmost horizontal completion to date in the Wolfcamp “D” formation in the Delaware Basin. This well flowed 270 BOE per day, including 232 Bbl of oil and 225 Mcf of natural gas per day (86%) oil at 1,150 psi surface pressure during its 24-hour initial potential test. Although the results of the Pickard State 20-18-34 #2H were more modest than our other Permian Basin wells, we were encouraged by the geopressured nature of this horizon, other zones of interest in the well and because this well established the producibility of hydrocarbons from the Wolfcamp “D” interval. Finally, in the Ranger prospect area, the Jim Rolfe 22-18-34 RN #131H was drilled and completed in the Third Bone Spring sand. This well flowed 260 Bbl per day of oil and 102 Mcf of natural gas per day at 560 psi on a 28/64-inch choke during its 24-hour initial potential test. This well has been turned to sales, and we are in the process of evaluating artificial lift for this well.

In the Rustler Breaks prospect area in Eddy County, New Mexico, our first Wolfcamp “B” test, the Rustler Breaks 12-24-27 #1H has also performed better than our original projections for this area. As of early February 2015, this well had produced 134,000 BOE (43% oil) in about nine months of production and was producing about 140 barrels of oil per day and 1.3 MMcf of natural gas per day.

As we completed and began producing oil and natural gas from these wells during 2014, our Permian Basin production increased significantly. Our average daily oil equivalent production from the Permian Basin grew ten-fold from 260 BOE per day in the fourth quarter of 2013 to 2,600 BOE per day in the fourth quarter of 2014. For the year ended December 31, 2014, 11% of our daily oil equivalent production, or 1,790 BOE per day, including 1,314 Bbl of oil per day and 2.9 MMcf of natural gas per day, was produced from the Permian Basin. The Permian Basin contributed approximately 14% of our daily oil production and approximately 7% of our daily natural gas production during 2014, as compared to only about 1% of our daily oil production and approximately 0.1% of our daily natural gas production during 2013. During the year ended December 31, 2013, only about 1% of our daily oil equivalent production, or 84 BOE per day, including 78 Bbl of oil per day and 36 Mcf of natural gas per day, was attributable to the Permian Basin.

Table of Contents

At December 31, 2014, approximately 19% of our estimated total proved oil and natural gas reserves, or 13.0 million BOE, was attributable to the Permian Basin, including approximately 8.1 million Bbl of oil and 29.9 Bcf of natural gas. Our proved reserves attributable to the Permian Basin increased substantially to 13.0 million BOE for the year ended December 31, 2014, as compared to 1.4 million BOE for the year ended December 31, 2013. Our Permian Basin proved reserves at December 31, 2014 comprised approximately 33% of our proved oil reserves and 11% of our proved natural gas reserves, as compared to approximately 7% of our proved oil reserves and 1% of our proved natural gas reserves at December 31, 2013. The PV-10 of our proved reserves in the Permian Basin at December 31, 2014 was $246.2 million, or approximately 24% of the PV-10 of our total proved reserves of $1.04 billion. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "— Estimated Proved Reserves."

At December 31, 2014, we had identified and engineered 1,445 gross (959.5 net) locations for potential future drilling on our Permian Basin acreage, primarily in the Wolfcamp or Bone Spring plays, but also including the Avalon and Delaware formations. These engineered locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our Permian Basin wells and other nearby wells based on available public data, drilling densities observed on properties of other operators, estimated horizontal lateral lengths, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other criteria. Our engineered well locations at December 31, 2014 do not yet include all portions of our acreage position, including the acreage associated with our Twin Lakes prospect area in Lea County, New Mexico or any locations associated with acreage from the HEYCO Merger. Our identified well locations presume that these properties may be developed on 80- to 160-acre well spacing, although we believe that denser well spacing may be possible and that multiple intervals may be prospective at any one surface location. As we explore and develop our Permian Basin acreage further, we anticipate that we may identify additional locations for future drilling. At December 31, 2014, these potential future drilling locations included only 19 gross (15.6 net) locations in the Permian Basin to which we have assigned proved undeveloped reserves.

At December 31, 2014, we were operating five contracted drilling rigs — two rigs in the Eagle Ford shale in South Texas and three rigs in the Permian Basin in Southeast New Mexico and West Texas. As a result of the sharp decline in commodity prices in recent months, we intend to scale back our drilling program during the first few months of 2015 to two rigs, both operating in the Permian Basin. In December 2014 and January 2015, we took delivery of two state-of-the-art, new-build rigs in the Permian Basin specifically configured for simultaneous operations and built to our specifications. These new rigs have full walking capabilities and high pressure circulating systems and are designed so that drilling operations can be conducted in the Wolfcamp formation while completion operations are performed in the Bone Spring or other intervals and vice versa—i.e., simultaneous drilling and completion operations. We expect the use of these rigs will result in additional operational efficiencies and will reduce the costs associated with our Permian Basin drilling program in 2015. We have allocated approximately $245.0 million, or approximately 70% of our 2015 capital expenditure budget of $350.0 million (excluding capital expenditures associated with the HEYCO Merger), to our anticipated drilling and completion activities in the Permian Basin, as well as for the acquisition of additional leasehold interests in the area. Our 2015 Permian Basin drilling program will focus on the development of the Wolf prospect area, the further delineation of our Ranger and Rustler Breaks prospect areas and the integration of the HEYCO acreage.

Northwest Louisiana and East Texas

We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana and East Texas during 2014, although we did participate in the drilling and completion of 46 gross (4.2 net) non-operated Haynesville shale wells. In the first half of 2014, Chesapeake began the process of drilling up to an anticipated 45 gross (8.7 net) Haynesville shale wells on our Elm Grove acreage in southern Caddo Parrish, Louisiana, which we expect to continue through 2017. We retain the right to participate for up to a 25% working interest in all wells drilled on this property with our working interest proportionately reduced to our leasehold position in any individual drilling unit. After notifying us of its intent to conduct this drilling program, Chesapeake began actively drilling these properties during the second quarter of 2014, and had up to five rigs operating on these properties at any one time during 2014. Approximately 7% of our total capital expenditures of $610.4 million were associated with non-operated Haynesville shale wells in 2014, including those wells drilled by Chesapeake. These wells are being drilled and completed in a multi-well batch mode, and as of December 31, 2014, Chesapeake had completed and placed 14 gross (3.3 net to us) wells on production. We do not plan to drill any operated Haynesville shale wells in 2015, but we have budgeted capital expenditures of approximately $15.0 million for our anticipated participation in 33 gross (2.3 net) Haynesville shale wells that we anticipate may be drilled or completed and placed on production by other operators on certain of our non-operated properties in 2015. Certain of these wells were already in progress at December 31, 2014. The most significant of these non-operated Haynesville shale wells will be 10 gross (1.8 net) wells that we expect to be completed and placed on production by Chesapeake on our Elm Grove acreage in 2015.

At December 31, 2014, we held approximately 27,300 gross (24,400 net) acres in Northwest Louisiana and East Texas, including 21,300 gross (13,600 net) acres in the Haynesville shale play. We operate all of our Cotton Valley and shallower production on our leasehold interests in Northwest Louisiana and East Texas, as well as all of our Haynesville production on the acreage outside of what we believe to be the core area of the Haynesville shale play. We operate approximately 36% of the 13,700 gross (6,800 net) acres that we consider to be in the core area of the Haynesville play.

For the year ended December 31, 2014, approximately 24% of our average daily oil equivalent production, or 3,791 BOE per day, including 17 Bbl of oil per day and 22.6 MMcf of natural gas per day, was attributable to our leasehold interests in Northwest Louisiana and East Texas. Natural gas production from these properties comprised approximately 54% of our daily natural gas production, but oil production from these properties comprised only about 0.2% of our daily oil production during 2014, as compared to approximately 58% of our daily natural gas production and approximately 0.3% of our daily oil production during 2013. During the year ended December 31, 2013, approximately 29% of our average daily oil equivalent production, or 3,431 BOE per day, including 17 Bbl of oil per day and 20.5 MMcf of natural gas per day, was attributable to our properties in Northwest Louisiana and East Texas.

For the year ended December 31, 2014, approximately 47% of our daily natural gas production, or 19.7 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 7%, or 2.9 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. For the year ended December 31, 2013, approximately 48% of our daily natural gas production, or 17.0 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 10%, or 3.5 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. At December 31, 2014, approximately 47% of our estimated total proved reserves, or 32.2 million BOE, was attributable to the Haynesville shale with another 2% of our proved reserves, or 1.2 million BOE, attributable to the Cotton Valley and shallower formations underlying this acreage.

Although we averaged production of only about 19.7 MMcf of natural gas per day from the Haynesville shale in 2014, our average daily natural gas production grew over three-fold during the year from almost 11.1 MMcf of natural gas per day in the fourth quarter of 2013 to approximately 35.0 MMcf of natural gas per day in the fourth quarter of 2014. This rapid growth in our Haynesville production was primarily due to the drilling and completion of 14 gross (3.3 net) non-operated Haynesville shale wells drilled by Chesapeake on our Elm Grove properties in Northwest Louisiana. Our Elm Grove properties are in what we believe is the core area of the Haynesville shale, and we anticipate the estimated ultimate recoveries from these wells at 8 to 12 Bcf each. Since January 1, 2015, Chesapeake has completed and placed on production three gross (0.5 net) additional wells. As a result, at February 27, 2015, we were producing over 50 MMcf of natural gas per day from the Haynesville shale.

At December 31, 2014, we had identified and engineered 471 gross (111.9 net) locations for potential future drilling in the Haynesville shale play and 71 gross (50.1 net) locations for potential future drilling in the Cotton Valley formation. These engineered locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Haynesville and Cotton Valley wells and other nearby wells based on available public data, drilling densities observed on properties of other operators, including on some of our non-operated properties, estimated horizontal lateral lengths, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface conditions, among other criteria. Of the 471 gross (111.9 net) locations identified for future drilling on our Haynesville acreage, 396 gross (58.0 net) locations have been identified within the 13,700 gross (6,800 net) acres that we believe are located in the core area of the Haynesville play. As we explore and develop our Northwest Louisiana and East Texas acreage further, we believe it is possible that we may identify additional locations for future drilling. At December 31, 2014, these potential future drilling locations included 127 gross (20.6 net) locations in the Haynesville shale (and no locations in the Cotton Valley) to which we have assigned proved undeveloped reserves.

Haynesville and Middle Bossier Shales

The Haynesville shale is an organically rich, overpressured marine shale found below the Cotton Valley and Bossier formations and above the Smackover formation at depths ranging from 10,500 to 13,500 feet across a broad region throughout Northwest Louisiana and East Texas, including principally Bossier, Caddo, DeSoto and Red River

Parishes in Louisiana and Harrison, Rusk, Panola and Shelby Counties in Texas. The Haynesville shale produces primarily dry natural gas with almost no associated liquids. The Bossier shale is overpressured and is often divided into lower, middle and upper units. The Middle Bossier shale appears to be productive for natural gas under large portions of DeSoto, Red River and Sabine Parishes in Louisiana and Shelby and Nacogdoches Counties in Texas, where it shares many similar productive characteristics with the deeper Haynesville shale. Although there is some overlap between the Haynesville and Bossier shale plays, the two plays appear quite distinct and a separate horizontal wellbore is typically needed for each formation.

At December 31, 2014, we had approximately 21,300 gross (13,600 net) acres in the Haynesville shale play, primarily in Northwest Louisiana. Based on our analysis of geologic and petrophysical information (including total organic carbon content and maturity, resistivity, porosity and permeability, among other information), well performance data, information available to us related to drilling activity and results from wells drilled across the Haynesville shale play, approximately 13,700 gross (6,800 net) acres are located in what we believe is the core area of the play. We believe the core area of the play includes that

Table of Contents

area in which the most Haynesville wells have been drilled by operators and from which we anticipate natural gas recoveries would likely exceed 6 Bcf per well. Almost all of our Haynesville acreage is held by production or consists of fee mineral interests that we own and portions of it are also producing from and, we believe, prospective for the Cotton Valley, Hosston (Travis Peak) and other shallower formations. In addition, we believe that approximately 1,700 net acres are prospective for the Middle Bossier shale play. We have never drilled a Middle Bossier shale well, and, although we believe that prospective well locations may exist on this acreage, we have not included any Middle Bossier locations in our engineered drilling locations at December 31, 2014.

Within the acreage that we believe to be in the core area of the Haynesville shale play, we are the operator of approximately 2,500 net acres. We have identified 32 gross (24.6 net) potential additional Haynesville locations that we may drill and operate in the future on this acreage. The remainder of our acreage in the core area of the Haynesville shale play is operated by other companies, including our Elm Grove properties in southern Caddo Parrish, Louisiana that are operated by Chesapeake following a sale of a portion of our interests there in July 2008. The working interests in our non-operated Haynesville wells are typically small, ranging from less than 1% to more than 30%.

Cotton Valley, Hosston (Travis Peak) and Other Shallower Formations

Prior to initiating natural gas production from the Haynesville shale in 2009, almost all of our production and reserves in Northwest Louisiana and East Texas was attributable to wells producing from the Cotton Valley formation. We own almost all of the shallow rights from the base of the Cotton Valley formation to the surface under our acreage in Northwest Louisiana and East Texas.

All of the shallow rights underlying our acreage in our Elm Grove properties in Northwest Louisiana, approximately 10,000 gross (9,800 net) acres at December 31, 2014, are held by existing production from the Cotton Valley formation or the Haynesville shale. The Cotton Valley formation was the primary producing zone in the Elm Grove field prior to discovery of the Haynesville shale. The Cotton Valley formation is a low permeability natural gas sand that ranges in thickness from 200 to 300 feet and has porosity ranging from 6% to 10%.

We have identified 71 gross (50.1 net) additional drilling locations for future Cotton Valley horizontal wells on our Elm Grove properties. We did not drill any of these locations in 2014 and do not plan to drill any of these locations in 2015. As long as this leasehold acreage is held by existing production from the vertical Cotton Valley wells or the deeper Haynesville shale wells, however, these Cotton Valley natural gas volumes remain available to be developed by us should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries.

We also continue to hold the shallow rights primarily by existing production on our Central and Southwest Pine Island, Longwood, Woodlawn and other prospect areas in Northwest Louisiana and East Texas. At December 31, 2014, we held an estimated 12,300 gross (9,800 net) leasehold and mineral acres by existing production in these areas.

Southwest Wyoming, Northeast Utah and Southeast Idaho — Meade Peak Shale

At December 31, 2014, we held leasehold interests in approximately 75,700 gross (35,700 net) acres in Southwest Wyoming and adjacent areas in Utah and Idaho as part of a natural gas shale exploration prospect targeting the Meade Peak shale. These leasehold interests are a combination of federal, state and fee mineral interests. We have entered into a participation and joint operating agreement with other parties covering the initial exploration effort, and if successful, the future development of this acreage. We are the operator of this prospect. We have drilled and completed one horizontal well on this acreage, but as of December 31, 2014, we had not established commercial natural gas production on this prospect. We had no production, no proved reserves and no engineered drilling locations attributable to this acreage at December 31, 2014. We have no plans to drill on this acreage in 2015.

Table of Contents

Operating Summary

The following table sets forth certain unaudited production data for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
Unaudited Production Data:			
Net Production Volumes:			
Oil (MBbl)	3,320	2,133	1,214
Natural gas (Bcf)	15.3	12.9	12.5
Total oil equivalent (MBOE) (1)	5,870	4,285	3,294
Average daily production (BOE/d) (1)	16,082	11,740	9,000
Average Sales Prices:			
Oil, with realized derivatives (per Bbl)	$88.94	$98.67	$103.55
Oil, without realized derivatives (per Bbl)	$87.37	$99.79	$101.86
Natural gas, with realized derivatives (per Mcf)	$5.06	$4.47	$3.55
Natural gas, without realized derivatives (per Mcf)	$5.08	$4.35	$2.59
Operating Expenses (per BOE):			
Production taxes and marketing	$5.65	$4.89	$3.54
Lease operating	$8.75	$9.04	$8.56
Depletion, depreciation and amortization	$22.95	$22.96	$24.43
General and administrative	$5.48	$4.85	$4.42

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth information regarding our average net daily production and total production for the year ended December 31, 2014 from our primary operating areas:

	Average Net Daily Production				
	Oil (Bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (BOE/d) (1)	Total Net Production (MBOE) (1)	Percentage of Total Net Production
South Texas:					
Eagle Ford (2)	7,764	16,423	10,501	3,833	65.3 %
NW Louisiana/E Texas:					
Haynesville	—	19,740	3,290	1,201	20.5 %
Cotton Valley (3)	17	2,903	501	183	3.1 %
Area Total	17	22,643	3,791	1,384	23.6 %
Permian Basin:					
SE New Mexico, West Texas	1,314	2,859	1,790	653	11.1 %
Other:					
Wyoming, Utah, Idaho	—	—	—	—	—
Total	9,095	41,925	16,082	5,870	100.0 %

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(2) Includes two wells producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(3) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

Table of Contents

The following table sets forth information regarding our average net daily production and total production for the year ended December 31, 2013 from our primary operating areas:

	Average Net Daily Production					
	Oil (Bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (BOE/d) (1)	Total Net Production (MBOE) (1)	Percentage of Total Net Production	
South Texas:						
Eagle Ford (2)	5,748	14,865	8,225	3,002	70.1	%
NW Louisiana/E Texas:						
Haynesville	—	16,984	2,831	1,033	24.1	%
Cotton Valley (3)	17	3,498	600	219	5.1	%
Area Total	17	20,482	3,431	1,252	29.2	%
Permian Basin:						
SE New Mexico, West Texas	78	36	84	31	0.7	%
Other:						
Wyoming, Utah, Idaho	—	—	—	—	—	
Total	5,843	35,383	11,740	4,285	100.0	%

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(2) Includes two wells producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(3) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

Our total oil equivalent production of approximately 5.9 million BOE for the year ended December 31, 2014 was an increase of 37% from our total oil equivalent production of approximately 4.3 million BOE for the year ended December 31, 2013. This increased production was primarily due to our drilling operations in the Eagle Ford shale, as well as contributions from our initial wells in the Permian Basin. Our average daily oil equivalent production for the year ended December 31, 2014 was 16,082 BOE per day, as compared to 11,740 BOE per day for the year ended December 31, 2013. Our average daily oil production for the year ended December 31, 2014 was 9,095 Bbl of oil per day, an increase of 56% from 5,843 Bbl of oil per day for the year ended December 31, 2013. Our average daily natural gas production for the year ended December 31, 2014 was 41.9 MMcf of natural gas per day, an increase of 18% from 35.4 MMcf of natural gas per day for the year ended December 31, 2013.

Producing Wells

The following table sets forth information relating to producing wells at December 31, 2014. Wells are classified as oil wells or natural gas wells according to their predominant production stream. We do not have any currently active dual completions. We have an approximate average working interest of 93% in all wells that we operate. For wells where we are not the operator, our working interests range from less than 1% to as much as 50%, and average approximately 10%. In the table below, gross wells are the total number of producing wells in which we own a working interest and net wells represent the total of our fractional working interests owned in the gross wells.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
South Texas:						
Eagle Ford (1)	113	95.2	4	4.0	117	99.2
NW Louisiana/E Texas:						
Haynesville	—	—	183	16.8	183	16.8

Cotton Valley (2)	2	2.0	95	60.4	97	62.4
Area Total	2	2.0	278	77.2	280	79.2
Permian Basin:						
SE New Mexico, West Texas	26	15.4	5	3.8	31	19.2
Other:						
Wyoming, Utah, Idaho	—	—	—	—	—	—
Total	141	112.6	287	85.0	428	197.6

Table of Contents

(1) Includes two wells producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.
(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

Estimated Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2014, 2013 and 2012. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, such as in the Eagle Ford shale and the Permian Basin, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. The reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC's rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that could be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

	At December 31, (1)		
	2014	2013	2012
Estimated Proved Reserves Data: (2)			
Estimated proved reserves:			
Oil (MBbl)	24,184	16,362	10,485
Natural Gas (Bcf) (3)	267.1	212.2	80.0
Total (MBOE) (4)	68,693	51,729	23,819
Estimated proved developed reserves:			
Oil (MBbl)	14,053	8,258	4,764
Natural Gas (Bcf) (3)	102.8	53.5	54.0
Total (MBOE) (4)	31,185	17,168	13,771
Percent developed	45.4 %	33.2 %	57.8 %
Estimated proved undeveloped reserves:			
Oil (MBbl)	10,131	8,104	5,721
Natural Gas (Bcf) (3)	164.3	158.7	26.0
Total (MBOE) (4)	37,508	34,561	10,048
PV-10 (5) (in millions)	$1,043.4	$655.2	$423.2
Standardized Measure (6) (in millions)	$913.3	$578.7	$394.6

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(1) Numbers in table may not total due to rounding.
(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the 12 months ended December 31, 2014 were $91.48 per Bbl for oil and $4.350 per MMBtu for natural gas, for the 12 months ended December 31, 2013 were $93.42 per Bbl for oil and $3.670 per MMBtu for natural gas, and for the 12 months ended December 31, 2012 were $91.21 per Bbl for oil and $2.757 per MMBtu for natural gas. These prices were adjusted by lease for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead. We report our proved reserves in two streams, oil and natural gas, and the economic value of the natural gas liquids associated with the natural gas is included in the

estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold.

(3) As a result of substantially lower natural gas prices in 2012, at June 30, 2012, we removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale from our total proved reserves, most of which were attributable to non-operated properties. Primarily as a result of the continued improvement in natural gas prices during 2013, we added approximately 134.2 Bcf (22.4 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale to our estimated total proved reserves in the second, third and fourth quarters of 2013, which are reflected in our estimated total proved reserves at December 31, 2014 and 2013.

(4) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies’ properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2014, 2013 and 2012 may be reconciled to our Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2014, 2013 and 2012 were, in millions, $130.1, $76.5 and $28.6, respectively.

Table of Contents

(6) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

Our estimated total proved oil and natural gas reserves increased 33% from 51.7 million BOE at December 31, 2013 to 68.7 million BOE at December 31, 2014. Our proved oil reserves grew 48% from approximately 16.4 million Bbl at December 31, 2013 to approximately 24.2 million Bbl at December 31, 2014. This increase is primarily attributable to proved oil reserves added due to our drilling operations in the Eagle Ford shale in South Texas and our delineation and development operations in the Permian Basin. Our proved natural gas reserves increased 26% from 212.2 Bcf at December 31, 2013 to 267.1 Bcf at December 31, 2014. This increase in our proved natural gas reserves was attributable to our drilling and completion activities in 2014 and to Chesapeake's drilling activities in the Haynesville shale on our Elm Grove properties that they operate. As a result of substantially lower natural gas prices in 2012, we removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale from our total proved reserves at June 30, 2012, most of which were attributable to non-operated properties. These proved undeveloped natural gas reserves were likewise not included in our estimated total proved reserves at December 31, 2012. During 2013, primarily as a result of continued improvement in natural gas prices during the year, we added approximately 134.2 Bcf (22.4 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale to our estimated total proved reserves in the second, third and fourth quarters of 2013, which are reflected in our estimated total proved reserves at December 31, 2014 and 2013. The PV-10 of our total proved oil and natural gas reserves increased 59% from $655.2 million at December 31, 2013 to $1.04 billion at December 31, 2014. Our total proved reserves at December 31, 2014 were made up of approximately 35% oil and 65% natural gas, as compared to 32% oil and 68% natural gas at December 31, 2013.

Our proved developed oil and natural gas reserves increased 81% from 17.2 million BOE at December 31, 2013 to 31.2 million BOE at December 31, 2014 due primarily to our drilling programs in the Eagle Ford shale, our delineation and development operations in the Permian Basin and Chesapeake's drilling activities in the Haynesville shale. Our proved developed oil reserves increased 70% from 8.3 million Bbl at December 31, 2013 to 14.1 million Bbl at December 31, 2014 as a result of our drilling operations in the Eagle Ford shale and our delineation and development operations in the Permian Basin. Our proved developed natural gas reserves almost doubled from 53.5 Bcf at December 31, 2013 to 102.8 Bcf at December 31, 2014 due primarily to Chesapeake's drilling activities in the Haynesville shale on our Elm Grove properties, which they operate.

The following table summarizes changes in our estimated proved developed reserves at December 31, 2014.

	Proved Developed Reserves (MBOE) [1]
As of December 31, 2013	17,168
Extensions and discoveries	8,778
Purchases of minerals-in-place	82
Revisions of prior estimates	(196)
Production	(5,870)
Conversion of proved undeveloped to proved developed	11,223
As of December 31, 2014	31,185

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Our proved undeveloped oil and natural gas reserves increased from 34.6 million BOE at December 31, 2013 to 37.5 million BOE at December 31, 2014. Our proved undeveloped oil reserves increased from 8.1 million Bbl at December 31, 2013 to 10.1 million Bbl at December 31, 2014, primarily as a result of our delineation and development operations in the Permian Basin. Our proved undeveloped natural gas reserves increased from 158.7 Bcf at December 31, 2013 to 164.3 Bcf at December 31, 2014 due primarily to our delineation and development operations in the Permian Basin and to wells drilled by our our co-working interest owners in the Haynesville shale. At December 31, 2014, we had no proved reserves in our estimates that remained undeveloped for five years or more following their booking.

Table of Contents

The following table summarizes changes in our estimated proved undeveloped reserves at December 31, 2014.

	Proved Undeveloped Reserves (MBOE) (1)
As of December 31, 2013	34,561
Extensions and discoveries	15,143
Purchases of minerals-in-place	—
Revisions of prior estimates	(973)
Conversion of proved undeveloped to proved developed	(11,223)
As of December 31, 2014	37,508

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth, since 2012, proved undeveloped reserves converted to proved developed reserves during each year and the investments associated with these conversions (dollars in thousands).

	Proved Undeveloped Reserves Converted to Proved Developed Reserves			Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves
	Oil (MBbl)	Natural Gas (Bcf)	Total (MBOE) (1)	
2012	283	0.8	415	$ 8,096
2013	2,944	8.3	4,334	115,699
2014	3,780	44.7	11,223	201,950
Total	7,007	53.8	15,972	$ 325,745

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth additional summary information by operating area with respect to our estimated net proved reserves at December 31, 2014:

	Net Proved Reserves (1)				
	Oil (MBbl)	Natural Gas (Bcf)	Oil Equivalent (MBOE) (4)	PV-10 (2) (in millions)	Standardized Measure (3) (in millions)
South Texas:					
Eagle Ford (5)	16,106	36.9	22,257	$603.8	$528.5
NW Louisiana/E Texas:					
Haynesville	—	193.1	32,183	183.7	160.8
Cotton Valley (6)	26	7.2	1,223	9.7	8.5
Area Total	26	200.3	33,406	193.4	169.3
Permian Basin:					
SE New Mexico, West Texas	8,052	29.9	13,030	246.2	215.5
Other:					
Wyoming, Utah, Idaho	—	—	—	—	—
Total	24,184	267.1	68,693	$1,043.4	$913.3

(1) Numbers in table may not total due to rounding.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2014 may be reconciled to our Standardized Measure of discounted future net cash flows at such date by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2014 were approximately $130.1 million.

Table of Contents

(3) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

(4) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) Includes two wells producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(6) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

Technology Used to Establish Reserves

Under current SEC rules, proved reserves are those quantities of oil and natural 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. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, we used technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and technical data used in the estimation of our proved reserves include, but are not limited to, electric logs, radioactivity logs, core analyses, geologic maps and available pressure and production data, seismic data and well test data. Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecast using a combination of production performance and analogy to offset production. Non-producing reserves estimates for both developed and undeveloped properties were forecast using either volumetric and/or analogy methods.

Internal Control Over Reserves Estimation Process

We maintain an internal staff of petroleum engineers and geoscience professionals to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. Our Vice President – Reservoir Engineering and Chief Technology Officer is primarily responsible for overseeing the preparation of our reserves estimates. He received his Bachelor and Master of Science degrees in Petroleum Engineering from Texas A&M University, is a Licensed Professional Engineer in the State of Texas and has over 37 years of industry experience. Following the preparation of our reserves estimates, these estimates are audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. The Engineering Committee of our Board of Directors reviews the reserves report and our reserves estimation process, and the results of the reserves report and the independent audit of our reserves are reviewed by other members of our Board of Directors, including members of our Audit Committee.

Table of Contents

Acreage Summary

The following table sets forth the approximate acreage in which we held a leasehold, mineral or other interest at December 31, 2014.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
South Texas:						
Eagle Ford	23,835	19,464	16,036	10,222	39,871	29,686
NW Louisiana/E Texas:						
Haynesville	17,605	9,884	3,690	3,687	21,295	13,571
Cotton Valley	18,776	16,675	3,586	3,073	22,362	19,748
Area Total (1)	22,895	20,555	4,356	3,841	27,251	24,396
Permian Basin:						
SE New Mexico, West Texas	9,287	7,109	83,395	58,967	92,682	66,076
Other:						
Wyoming, Utah, Idaho	1,600	800	74,074	34,932	75,674	35,732
Total	57,617	47,928	177,861	107,962	235,478	155,890

(1) Some of the same leases cover the gross and net acreage shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the gross and net acreage for both formations is not equal to the total gross and net acreage for Northwest Louisiana and East Texas.

Undeveloped Acreage Expiration

The following table sets forth the approximate number of gross and net undeveloped acres at December 31, 2014 that will expire prior to December 31, 2016 by operating area unless production is established within the spacing units covering the acreage prior to the expiration dates, the existing leases are renewed prior to expiration or continued operations maintain the leases beyond the expiration of each respective primary term.

	Acres Expiring 2015		Acres Expiring 2016	
	Gross	Net	Gross	Net
South Texas:				
Eagle Ford	1,607	1,193	2,631	2,468
NW Louisiana/E Texas:				
Haynesville	—	—	839	837
Cotton Valley	—	—	80	80
Area Total (1)	—	—	839	837
Permian Basin:				
SE New Mexico, West Texas (2)	5,875	5,285	32,918	21,325
Other:				
Wyoming, Utah, Idaho	—	—	—	—
Total	7,482	6,478	36,388	24,630

(1) Some of the same leases cover the gross and net acreage shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the gross and net acreage for both formations is not equal to the total gross and net acreage for Northwest Louisiana and East Texas.

(2) Approximately 60% of the acreage expiring in 2016 is associated with our Twin Lakes prospect in northern Lea County, New Mexico. Most of these leases can be extended for an additional two years, should we choose to do so, by paying an additional lease bonus.

Many of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless operations are conducted which will serve to maintain the respective leases in effect beyond the expiration of the primary term or production from the acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production in commercial quantities in most cases. We also have options to extend some of our leases through payment of additional lease bonus payments prior to the expiration of the primary term of the leases. In addition, we may attempt to secure a new lease upon the expiration of certain of our acreage; however, there may be third party leases that become effective immediately if our leases expire at the end of their respective terms and production has not been established prior to such date or operations are not conducted to maintain the leases in effect beyond the primary term. As of December 31, 2014, our leases are mainly fee leases with primary terms of three to five years. We believe that our lease terms are similar to our competitors' fee lease terms as they relate to both primary term and royalty interests.

Table of Contents

Drilling Results

The following table summarizes our drilling activity for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	89	39.9	32	20.7	36	17.1
Dry	—	—	—	—	—	—
Exploration Wells						
Productive	12	10.6	14	8.7	22	10.4
Dry (1)	—	—	1	0.4	—	—
Total Wells						
Productive	101	50.5	46	29.4	58	27.5
Dry (1)	—	—	1	0.4	—	—

(1) We participated on a non-operated basis in an unsuccessful vertical well test of the Edwards formation on our Atascosa County, Texas acreage in 2013.

Marketing

Our crude oil is generally sold under short-term, extendable and cancellable agreements with unaffiliated purchasers based on published price bulletins reflecting an established field posting price. As a consequence, the prices we receive for crude oil and a portion of our heavier liquids move up and down in direct correlation with the oil market as it reacts to supply and demand factors. The prices of the remaining lighter liquids move up and down independently of any relationship between the crude oil and natural gas markets. Transportation costs related to moving crude oil and liquids are also deducted from the price received for crude oil and liquids.

Our natural gas is sold under both long-term and short-term natural gas purchase agreements. Natural gas produced by us is sold at various delivery points at or near producing wells to both unaffiliated independent marketing companies and unaffiliated midstream companies. We receive proceeds from prices that are based on various pipeline indices less any associated fees. When there is an opportunity to do so, the midstream companies may, at our request, process our natural gas at a processing facility and extract liquid hydrocarbons from the natural gas. We are then paid for the extracted liquids based on either a negotiated percentage of the proceeds that are generated from the midstream companies' sale of the liquids, or other negotiated pricing arrangements using then-current market pricing less fixed rate processing, transportation and fractionation fees.

The prices we receive for our oil and natural gas production fluctuate widely. Factors that cause price fluctuations include the level of demand for oil and natural gas, the actions of OPEC, weather conditions, hurricanes in the Gulf Coast region, natural gas storage levels, domestic and foreign governmental regulations, price and availability of alternative fuels, political conditions in oil and natural gas producing regions, the domestic and foreign supply of oil and natural gas, the price of foreign imports and overall economic conditions. Decreases in these commodity prices adversely affect the carrying value of our proved reserves and our revenues, profitability and cash flows. Short-term disruptions of our oil and natural gas production occur from time to time due to downstream pipeline system failure, capacity issues and scheduled maintenance, as well as maintenance and repairs involving our own well operations. These situations, if they occur, curtail our production capabilities and ability to maintain a steady source of revenue. In addition, demand for natural gas has historically been seasonal in nature, with peak demand and typically higher prices during the colder winter months. See "Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations."

For the year ended December 31, 2014, we had three significant purchasers that accounted for approximately 68% of our total oil, natural gas and natural gas liquids revenues. For the years ended December 31, 2013 and 2012, we had five and three significant purchasers that accounted for approximately 87% and 74%, respectively, of our total oil, natural gas and natural gas liquids revenues. Due to the nature of the markets for oil, natural gas and natural gas liquids, we do not believe that the loss of any one of these purchasers would have a material adverse impact on our financial condition, results of operations or cash flows for any significant period of time.

Effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement whereby we committed to transport the anticipated natural gas production from a significant portion of our Eagle Ford acreage in South Texas through the counterparty's system for processing at the counterparty's facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty's processing plant downstream for fractionation. After processing, the residue natural gas is purchased by the counterparty at the tailgate of its processing plant and further transported under its natural gas transportation agreements. The arrangement contains fixed processing and liquids transportation and fractionation fees, and the revenue we receive varies with the quality of natural gas transported to the processing facilities and the contract period.

Under this natural gas processing and transportation agreement, if we do not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, we will be required to pay a deficiency fee per MMBtu of natural gas deficiency. Any quantity in excess of the maximum MMBtu delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. During certain prior periods, we had an immaterial natural gas deficiency and the counterparty to this agreement waived the deficiency fee. See "Risk Factors — The Marketability of Our Production Is Dependent upon Oil and Natural Gas Gathering, Processing and Transportation Facilities Owned and Operated by Third Parties, and the Unavailability of Satisfactory Oil and Natural Gas Gathering, Processing and Transportation Arrangements Would Have a Material Adverse Effect on Our Revenue."

Title to Properties

We endeavor to assure that title to our properties is in accordance with standards generally accepted in the oil and natural gas industry. Some of our acreage will be obtained through farmout agreements, term assignments and other contractual arrangements with third parties, the terms of which often will require the drilling of wells or the undertaking of other exploratory or development activities in order to retain our interests in the acreage. Our title to these contractual interests will be contingent upon our satisfactory fulfillment of these obligations. Our properties are also subject to customary royalty interests, liens incident to financing arrangements, operating agreements, taxes and other burdens that we believe will not materially interfere with the use and operation of or affect the value of these properties. We intend to maintain our leasehold interests by conducting operations, making lease rental payments or producing oil and natural gas from wells in paying quantities, where required, prior to expiration of various time periods to avoid lease termination. Certain of the leases that we have obtained to date have been purchased by and in the name of professional lease brokers as our nominee. See "Risk Factors — We May Incur Losses or Costs as a Result of Title Deficiencies in the Properties in Which We Invest."

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during winter months and decrease during summer months. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can place increased demand on storage volumes. Demand for oil and heating oil is also generally higher in the winter and the summer driving season, although oil prices are impacted more significantly by global supply and demand. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations. Certain of our drilling, completion and other operations are also subject to seasonal limitations.

Competition

The oil and natural gas industry is highly competitive. We compete and will continue to compete with major and independent oil and natural gas companies for exploration opportunities, acreage and property acquisitions. We also compete for drilling rig contracts and other equipment and labor required to drill, operate and develop our properties. Most of our competitors have substantially greater financial resources, staffs, facilities and other resources. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be willing and able to pay more for drilling rigs or exploratory prospects and productive oil and natural gas properties and may be able to identify, evaluate, bid for and purchase a greater number of properties and prospects than we can.

Our competitors may also be able to afford to purchase and operate their own drilling rigs and hydraulic fracturing equipment.

Our ability to drill and explore for oil and natural gas and to acquire properties will depend upon our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. We have been conducting field operations since 2004 while many of our competitors may have a longer history of operations. Additionally, most of our competitors have demonstrated the ability to operate through industry cycles.

The oil and natural gas industry also competes with other energy-related industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. See “Risk Factors — Competition in the Oil and Natural Gas

Table of Contents

Industry Is Intense, Making It More Difficult for Us to Acquire Properties, Market Oil and Natural Gas and Secure Trained Personnel."

Regulation

Oil and Natural Gas Regulation

Our oil and natural gas exploration, development, production and related operations are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial monetary penalties or delay or suspension of operations. The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these laws, rules and regulations are frequently amended or reinterpreted and new laws, rules and regulations are promulgated, we are unable to predict the future cost or impact of complying with the laws, rules and regulations to which we are, or will become, subject. Our competitors in the oil and natural gas industry are generally subject to the same regulatory requirements and restrictions that affect our operations. We cannot predict the impact of future government regulation on our properties or operations.

Texas, New Mexico, Louisiana, Wyoming, Idaho and Utah and many other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration, development and production of oil and natural gas. Many states also have statutes or regulations addressing conservation of oil and natural gas and other matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, the regulation of well spacing, the surface use and restoration of properties upon which wells are drilled, the prohibition or restriction on venting or flaring natural gas, the sourcing and disposal of water used in the drilling and completion process and the plugging and abandonment of these wells. Many states restrict production to the market demand for oil and natural gas. Some states have enacted statutes prescribing ceiling prices for natural gas sold within their boundaries. Additionally, some regulatory agencies have, from time to time, imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below natural production capacity in order to conserve supplies of oil and natural gas. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Some of our oil and natural gas leases are issued by agencies of the federal government, as well as agencies of the states in which we operate. These leases contain various restrictions on access and development and other requirements that may impede our ability to conduct operations on the acreage represented by these leases.

Our sales of natural gas, as well as the revenues we receive from our sales, are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission, or FERC, under the Natural Gas Act of 1938, or the NGA, as well as under Section 311 of the Natural Gas Policy Act of 1978, or the NGPA. Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis. The natural gas industry has historically, however, been heavily regulated and we can give no assurance that the current less stringent regulatory approach of FERC will continue.

In 2005, Congress enacted the Domenici-Barton Energy Policy Act of 2005, or the Energy Policy Act. The Energy Policy Act, among other things, amended the NGA to prohibit market manipulation by any entity, to direct FERC to facilitate market transparency in the market for the sale or transportation of physical natural gas in interstate commerce and to significantly increase the penalties for violations of the NGA, the NGPA or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act. Should we violate the anti-market manipulation laws and related regulations, in addition to FERC-imposed penalties, we may also be subject to third-party damage claims.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Because these regulations will apply to all intrastate natural gas shippers within the same state on a comparable basis, we believe that the regulation in any states in which we

operate will not affect our operations in any way that is materially different from our competitors that are similarly situated.
Natural gas gathering facilities are exempt from the jurisdiction of FERC under section 1(b) of the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.
The price we receive from the sale of oil and natural gas liquids will be affected by the availability, terms and cost of transportation of the products to market. Under rules adopted by FERC, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. Intrastate oil pipeline transportation rates

Table of Contents

are subject to regulation by state regulatory commissions, which varies from state to state. We are not able to predict with certainty the effects, if any, of these regulations on our operations.

In 2007, the Energy Independence & Security Act of 2007, or the EISA, went into effect. The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations and establishes penalties for violations thereunder. We cannot predict any future laws or regulations or their impact.

U.S. Federal and State Taxation

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases may occur. In addition, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals. President Obama has proposed sweeping changes to federal laws on the income taxation of small oil and natural gas exploration and production companies like ours. Among other issues, President Obama has proposed to eliminate allowing small U.S. oil and natural gas companies to deduct intangible drilling costs as incurred and percentage depletion. Changes to tax laws could adversely affect our business and our financial results. See “Risk Factors — We Are Subject to Federal, State and Local Taxes, and May Become Subject to New Taxes or Have Eliminated or Reduced Certain Federal Income Tax Deductions Currently Available with Respect to Oil and Natural Gas Exploration and Production Activities as a Result of Future Legislation, Which Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.”

Hydraulic Fracturing Policies and Procedures

We use hydraulic fracturing as a means to maximize the recovery of oil and natural gas in almost every well that we drill and complete. Our engineers responsible for these operations attend specialized hydraulic fracturing training programs taught by industry professionals. Although average drilling and completion costs for each area will vary, as will the cost of each well within a given area, on average approximately one-half to two-thirds of the total well costs for our horizontal wells are attributable to overall completion activities, which are primarily focused on hydraulic fracture treatment operations. These costs are treated in the same way that all other costs of drilling and completion of our wells are treated and are built into and funded through our normal capital expenditure budget. A change to any federal and state laws and regulations governing hydraulic fracturing could impact these costs and adversely affect our business and financial results. See “Risk Factors — Federal and State Legislation and Regulatory Initiatives Relating to Hydraulic Fracturing Could Result in Increased Costs and Additional Operating Restrictions or Delays.”

The protection of groundwater quality is important to us. We believe that we follow all state and federal regulations and apply industry standard practices for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators (including the Bureau of Land Management (“BLM”) with respect to federal acreage).

Although rare, if and when the cement and steel casing used in well construction requires remediation, we deal with these problems by evaluating the issue and running diagnostic tools, including cement bond logs, temperature logs and pressure testing, followed by pumping remedial cement jobs and other appropriate remedial measures.

The vast majority of hydraulic fracturing treatments are made up of water and sand or other kinds of man-made propping agents. We use major hydraulic fracturing service companies who track and report chemical additives that are used in the fracturing operation as required by the appropriate governmental agencies. These service companies fracture stimulate thousands of wells each year for the industry and invest millions of dollars to protect the environment through rigorous safety procedures, and also work to develop more environmentally friendly fracturing fluids. We also follow safety procedures and monitor all aspects of the fracturing operation in an attempt to ensure environmental protection. We do not pump any diesel in the fluid systems of any of our fracture stimulation procedures.

While current fracture stimulation procedures utilize a significant amount of water, we typically recover less than 10% of this fracture stimulation water before produced salt water becomes a significant portion of the fluids produced. All produced water, including fracture stimulation water, is disposed of in permitted and regulated disposal facilities in a way that is designed to avoid any impact to surface waters.

Environmental Regulation

The exploration, development and production of oil and natural gas, including the operation of salt water injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, drilling, completing and operating oil and natural gas wells. Our activities are subject to a variety of environmental laws and regulations, including but not limited to: the Oil Pollution Act of 1990, or the

Table of Contents

OPA 90, the Clean Water Act, or the CWA, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, the Resource Conservation and Recovery Act, or RCRA, the Clean Air Act, or the CAA, the Safe Drinking Water Act, or the SDWA, and the Occupational Safety and Health Act, or OSHA, as well as comparable state statutes and regulations. We are also subject to regulations governing the handling, transportation, storage and disposal of wastes generated by our activities and naturally occurring radioactive materials, or NORM, that may result from our oil and natural gas operations. Administrative, civil and criminal fines and penalties may be imposed for noncompliance with these environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking some activities, limit or prohibit other activities because of protected wetlands, areas or species and require investigation and cleanup of pollution. We expect to remain in compliance in all material respects with currently applicable environmental laws and regulations and expect that these laws and regulations will not have a material adverse impact on us.

The OPA 90 and its regulations impose requirements on “responsible parties” related to the prevention of crude oil spills and related to liability for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A “responsible party” under the OPA 90 may include the owner or operator of an onshore facility. The OPA 90 subjects responsible parties to strict, joint and several financial liability for removal costs and other damages, including natural resource damages, caused by an oil spill that is covered by the statute. It also imposes other requirements on responsible parties, such as the preparation of an oil spill contingency plan. Failure to comply with the OPA 90 may subject a responsible party to civil or criminal enforcement action. We may conduct operations on acreage located near, or that affects, navigable waters subject to the OPA 90. We believe that compliance with applicable requirements under the OPA 90 will not have a material adverse effect on us.

The CWA and comparable state laws impose restrictions and strict controls regarding the discharge of produced waters, fill materials and other materials into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits are required to discharge pollutants into certain state and federal waters and to conduct construction activities in those waters and wetlands. Certain state regulations and the general permits issued under the federal National Pollutant Discharge Elimination System program prohibit the discharge of produced water, produced sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the U.S. Environmental Protection Agency, or the EPA, has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other pollutants and impose liability for the costs of removal or remediation of contamination resulting from such discharges. In furtherance of the CWA, the EPA promulgated the Spill Prevention, Control, and Countermeasure regulations, which require certain oil-storing facilities to prepare plans and meet construction and operating standards.

CERCLA, also known as the “Superfund” law, imposes liability, without regard to fault or the legality of the original conduct, on various classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Persons who are 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 and for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. Although CERCLA generally exempts petroleum from the definition of hazardous substances, our operations may, and in all likelihood will, involve the use or handling of materials that may be classified as hazardous substances under CERCLA. Many states have adopted similar statutes. Certain state statutes may impose liability for a broader range of contaminants and may not contain a similar exemption for petroleum. Furthermore, we may acquire or operate properties that unknown to us have been subjected to, or have caused or contributed to, prior releases of hazardous substances or other materials requiring remediation.

RCRA and comparable state and local statutes govern the management, including treatment, storage and disposal, of both hazardous and nonhazardous solid wastes. We generate hazardous and nonhazardous solid waste in connection with our routine operations. At present, RCRA includes a statutory exemption that allows many wastes associated with crude oil and natural gas exploration and production to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. Not all of the wastes we generate fall within these exemptions. At various times in the past, proposals have been made to amend RCRA to eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses. Hazardous wastes are subject to more stringent and costly disposal requirements than are nonhazardous wastes.

The CAA, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including oil and natural gas production. These laws and any implementing regulations impose stringent air permit requirements and require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, or to use specific equipment or technologies to control emissions. On April 17, 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. Further, the finalized regulations also established specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. In December 2014, the EPA issued finalized additional amendments to these rules that, among other things, distinguished between multiple flowback stages during completion of hydraulically fractured wells and clarified that storage tanks permanently removed from service are not affected by any requirements. These rules have required changes to our operations, including the installation of new equipment to control emissions. We continue to evaluate the effect these rules have on our business and operations, which effects we do not expect to be material. Further, in 2012, seven states sued the EPA to compel the agency to make a determination as to whether setting standards of performance limiting methane emissions from oil and natural gas sources is appropriate and, if so, to promulgate performance standards for methane emissions from existing oil and natural gas sources. In April 2014, the EPA released a set of five white papers analyzing methane emissions from the industry. In January 2015, EPA announced plans to issue a rule in summer 2015 governing methane emissions from the oil and natural gas industry. The Bureau of Land Management (BLM) is also expected to address methane emissions from the oil and natural gas industry on federal lands. These rules could increase our operating costs and have a material adverse effect on our business and operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, cleanup or operating requirements could materially adversely affect our operations and financial condition, as well as those of the oil and natural gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” and including carbon dioxide and methane, may be contributing to the warming of the Earth’s atmosphere. As a result, there have been attempts to pass comprehensive greenhouse gas legislation. To date, such legislation has not been enacted. Any future international agreements, federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could, and in all likelihood would, require us to incur increased operating costs adversely affecting our profits and could adversely affect demand for the oil and natural gas we produce, depressing the prices we receive for oil and natural gas.

The EPA has adopted rules under the CAA for the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration (“PSD”) and Title V permitting programs. The EPA has adopted a multi-tiered approach to this permitting, with the largest sources first subject to permitting. In addition, on October 30, 2009, the EPA published a rule requiring the reporting of greenhouse gas emissions from specified sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA released a rule that expands its final rule on greenhouse gas emissions reporting to include owners and operators of onshore and offshore oil and natural gas production, onshore natural gas processing, natural gas storage, natural gas transmission and natural gas distribution facilities. Reporting of greenhouse gas emissions from such onshore production was first required on an annual basis in 2012 for emissions occurring in 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could, and in all likelihood will, require us to incur costs to reduce emissions of greenhouse gases associated with our operations adversely affecting our profits or could adversely affect demand for the oil and natural gas we produce, depressing the prices we receive for oil and natural gas.

Some states have begun taking actions to control and/or reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or state or regional greenhouse gas cap-and-trade programs. Although most of the state-level initiatives have to date focused on significant sources of greenhouse gas emissions, such as coal-fired electric plants, it is possible that less significant sources of emissions could become subject to greenhouse gas emission limitations or emissions allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. In our industry, underground injection not only allows us to economically dispose of produced water, but if injected into an oil bearing zone, it can increase the oil production from such zone. The SDWA establishes a regulatory framework for underground injection, the primary objective of which is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. The disposal of hazardous waste by underground injection is subject to stricter requirements than the disposal of produced water. As of December 31, 2014, we owned and operated five underground injection wells and expect to own other similar wells. Failure to obtain, or abide by, the requirements for the issuance of necessary permits could subject us to civil and/or criminal enforcement actions and penalties. In addition, in some instances, the operation of underground injection wells has been alleged to cause earthquakes (induced seismicity) as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. We do not expect these developments to have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our activities involve the use of hydraulic fracturing. For more information on our hydraulic fracturing operations, see "— Hydraulic Fracturing Policies and Procedures." Recently, there has been increasing regulatory scrutiny of hydraulic fracturing, which is generally exempted from regulation as underground injection (unless diesel is a component of the fracturing fluid) on the federal level pursuant to the SDWA. However, the U.S. Senate and House of Representatives have considered legislation to repeal this exemption. If enacted, these proposals would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities. If enacted, such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements. These legislative proposals have also contained language to require the reporting and public disclosure of chemicals used in the hydraulic fracturing process. If the exemption for hydraulic fracturing is removed from the SDWA, or if other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition, results of operations and cash flows.

In addition, in some states and localities, there has been a push to place additional regulatory burdens upon hydraulic fracturing activities and, in some areas, to severely restrict or prohibit those activities. At the state level, Texas and Wyoming, for example, have enacted requirements for the disclosure of the composition of the fluids used in hydraulic fracturing. In addition, at least a few state and local governments or regional authorities have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address hydraulic fracturing activities. For example, in December 2014 New York announced a moratorium on high volume fracturing activities combined with horizontal drilling following the issuance of a study regarding the safety of hydraulic fracturing. Certain communities in Colorado have also enacted bans on hydraulic fracturing. Voters in the city of Denton, Texas also recently approved a moratorium on hydraulic fracturing. These actions are the subject of legal challenges. Additional burdens upon hydraulic fracturing, such as reporting or permitting requirements, will result in additional expense and delay in our operations.

The EPA has recently asserted federal regulatory authority over hydraulic fracturing using diesel under the SDWA's Underground Injection Control Program. The EPA recently issued SDWA permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. Although we do not currently pump diesel in the fluid systems of any of our fracture stimulation procedures, any such change in our practices may cause us to be subject to this guidance. In addition, the EPA is currently conducting a study on the effects of hydraulic fracturing on drinking water resources. A progress report was released in December 2012, with draft final results expected in early 2015. Further, the BLM has proposed rules to regulate hydraulic fracturing on federal lands. The EPA has also announced an Advance Notice of Proposed Rulemaking under the Toxic Substance Control Act to develop regulations governing the disclosure of hydraulic fracturing chemicals.

Oil and natural gas exploration and production, operations and other activities have been conducted at some of our properties by previous owners and operators. Materials from these operations remain on some of the properties, and, in some instances, require remediation. In addition, we occasionally must agree to indemnify sellers of producing properties from whom we acquire the properties against some of the liability for environmental claims associated with the properties. While we do not believe that costs we incur for compliance with environmental regulations and remediating previously or currently owned or operated properties will be material, we cannot provide any assurances that these costs will not result in material expenditures that adversely affect our profitability.

Additionally, in the course of our routine oil and natural gas operations, surface spills and leaks, including casing leaks, of oil or other materials will occur, and we will incur costs for waste handling and environmental compliance. It is also possible that our oil and natural gas operations may require us to manage NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contact with crude oil and natural gas production and processing streams. Some states, including Texas,
have enacted regulations governing the handling, treatment, storage and disposal of NORM. Moreover, we will be able to control directly the operations of only those wells for which we act as the operator. Despite our lack of control over wells owned partly by us but operated by others, the failure of the operator to comply with the applicable environmental regulations may, in certain circumstances, be attributable to us.

We are subject to the requirements of OSHA and comparable state statutes. The OSHA Hazard Communication Standard, the "community right-to-know" regulations under Title III of the federal Superfund Amendments and Reauthorization Act and

Table of Contents

similar state statutes require us to organize information about hazardous materials used, released or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in OSHA workplace standards.

The Endangered Species Act, or ESA, was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in material restrictions on land use and may materially impact oil and natural gas development. If a portion of our leases were designated as critical or suitable habitat, our ability to maximize production from our leases may be adversely impacted.

We have not in the past been, and do not anticipate in the near future to be, required to expend amounts that are material in relation to our total capital expenditures as a result of environmental laws and regulations, but since these laws and regulations are periodically amended, we are unable to predict the ultimate cost of compliance. We have no assurance that more stringent laws and regulations protecting the environment will not be adopted or that we will not otherwise incur material expenses in connection with environmental laws and regulations in the future. See "Risk Factors — We Are Subject to Government Regulation and Liability, Including Complex Environmental Laws, Which Could Require Significant Expenditures."

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. The EPA has announced that one of its enforcement initiatives for 2014 to 2016 is to focus on compliance by the energy extraction sector. Any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial condition. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we have no assurance that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons.

We maintain insurance against some, but not all, potential risks and losses associated with our industry and operations. We do not currently carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could materially adversely affect our financial condition, results of operations and cash flows.

Office Lease

Our corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. See "Note 13 – Commitments and Contingencies" to the consolidated financial statements in this Annual Report on Form 10-K. Such information is incorporated herein by reference.

Employees

At December 31, 2014, we had 99 full-time employees. We believe that our relationships with our employees are satisfactory. No employee is covered by a collective bargaining agreement. From time to time, we use the services of independent consultants and contractors to perform various professional services, particularly in the areas of geology and geophysics, production operations, construction, design, well site surveillance and supervision, permitting and environmental assessment and legal and income tax preparation and accounting services. Independent contractors, at our request, drill all of our wells and usually perform field and on-site production operation services for us, including facilities construction, pumping, maintenance, dispatching, inspection and testing. If significant opportunities for company growth arise and require additional management and professional expertise, we will seek to employ qualified individuals to fill positions where that expertise is necessary to develop those opportunities.

Available Information

Our Internet website address is www.matadorresources.com. We make available, free of charge, through our website, 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 providing such reports to the SEC. Also, the charters of our

Audit Committee, Corporate Governance Committee, Executive Committee and Nominating, Compensation and Planning Committee, and our Code of Ethics and Business Conduct for Officers, Directors and Employees, are available through our website, and we also intend to disclose any amendments to our Code of Ethics and Business Conduct, or waivers to such code on behalf of our Chief Executive Officer, Chief Financial Officer or Chief Accounting Officer, on our website. All of these corporate governance materials are available free of charge and in print to any shareholder who provides a written request to the Corporate Secretary at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. The contents of our website are not intended to be incorporated by reference into this Annual Report on Form 10-K or any other report or document we file and any reference to our website is intended to be an inactive textual reference only.

Item 1A. Risk Factors.

Risks Related to the Oil and Natural Gas Industry and Our Business

Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations.

The prices we receive for our oil and natural gas heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital, borrowing capacity under our Credit Agreement and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile and will likely continue to be volatile in the future. During 2014, the price of oil decreased 50% from a high of $107.26 per Bbl in mid-June to a low of $53.27 per Bbl in late December, and the price of natural gas decreased 53% from a high of $6.15 per MMBtu in mid-February to a low of $2.89 per MMBtu in late December. Any substantial and extended decline in the price of oil or natural gas could have an adverse effect on our borrowing capacity, our ability to obtain additional capital, and our revenues, profitability and cash flows. Further, because we use the full-cost method of accounting, we perform a ceiling test quarterly that may be impacted by declining prices of oil and natural gas. Significant price declines may cause us to recognize a full-cost ceiling impairment, which reduces the book value of our net tangible assets, retained earnings and shareholders' equity but does not impact our cash flows from operations, liquidity or capital resources. See "—We May Be Required to Write Down the Carrying Value of Our Proved Properties under Accounting Rules and These Write-Downs Could Adversely Affect Our Financial Condition."

The prices we receive for our production, and the levels of our production, depend on numerous factors. These factors include, but are not limited to, the following:

- the domestic and foreign supply of oil and natural gas;
- the domestic and foreign demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC, and state-controlled oil companies relating to oil price and production controls;
- the prices and availability of competitors' supplies of oil and natural gas;
- the price and quantity of foreign imports;
- the impact of U.S. dollar exchange rates on oil and natural gas prices;
- domestic and foreign governmental regulations and taxes;
- speculative trading of oil and natural gas futures contracts;
- the availability, proximity and capacity of gathering, processing and transportation systems for natural gas;
- the availability of refining capacity;
- the prices and availability of alternative fuel sources;
- weather conditions and natural disasters;
- political conditions in or affecting oil and natural gas producing regions or countries, including the Middle East, South America and Russia;
- the continued threat of terrorism and the impact of military action and civil unrest;
- public pressure on, and legislative and regulatory interest within, federal, state and local governments to stop, significantly limit or regulate hydraulic fracturing activities;
- the level of global oil and natural gas inventories and exploration and production activity;
- the impact of energy conservation efforts;
- technological advances affecting energy consumption; and

- overall worldwide economic conditions.

These factors make it difficult to predict future commodity price movements with any certainty. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices and are not pursuant to long-term fixed price contracts. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other.

Approximately 57% of our total production during the year ended December 31, 2014 and 35% of our proved reserves at December 31, 2014 were attributable to oil. Approximately 43% of our total production during the year ended December 31, 2014 and 65% of our proved reserves at December 31, 2014 were attributable to natural gas.

During 2015, we plan to direct approximately 70% of our capital expenditures to the Wolfcamp and Bone Spring plays in the Permian Basin and 26% of our capital expenditures to the Eagle Ford shale, each of which is prospective for oil and liquids production. These opportunities are sensitive to changes in oil prices.

Declines in oil or natural gas prices not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically and could reduce the amount we may borrow under our Credit Agreement. Should oil or natural gas prices decrease to economically unattractive levels and remain there for an extended period of time, we may elect in the future to delay some of our exploration and development plans for our prospects, or to cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities (as we have done with our operated natural gas properties in recent years), each of which would have a material adverse effect on our business, financial condition, results of operations and reserves. In addition, such declines in commodity prices could cause a reduction in our borrowing base. If the borrowing base were to be less than the outstanding borrowings under our Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or repay the deficit in equal installments over a period of six months.

Our Exploration, Development and Exploitation Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth.

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the exploration, development, exploitation, production and acquisition of oil and natural gas reserves. Our cash, operating cash flows and potential future borrowings under our Credit Agreement or otherwise may not be sufficient to fund all of our future acquisitions or future capital expenditures. The rate of our future growth is dependent, at least in part, on our ability to access capital at rates and on terms we determine to be acceptable.

We may sell additional equity securities or issue debt securities to raise capital. If we succeed in selling additional equity securities or securities convertible into equity securities to raise funds or make acquisitions, the ownership of our existing shareholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing shareholders. If we raise additional capital through the issuance of new debt securities or additional indebtedness, we may become subject to additional covenants that restrict our business activities.

Our cash flows from operations and access to capital are subject to a number of variables, including:

- our estimated proved oil and natural gas reserves;
- the amount of oil and natural gas we produce from existing wells;
- the prices at which we sell our production;
- the costs of developing and producing our oil and natural gas reserves;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of banks to lend to us; and
- our ability to access the equity and debt capital markets.

In addition, the possible occurrence of future events, such as terrorist attacks, wars or combat peace-keeping missions, financial market disruptions, general economic recessions, oil and natural gas industry recessions, significant decreases in the prices of oil and natural gas, large company bankruptcies, accounting scandals, overstated reserves estimates by major public oil companies and disruptions in the financial and capital markets, has caused financial institutions, credit rating agencies and the public to more closely review the financial statements, capital structures and earnings of public companies, including energy companies. Such events have constrained the capital available to the energy industry in the past, and such events or similar events could adversely affect our access to funding for our operations in the future.

Table of Contents

If our revenues decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, further develop and exploit our current properties or invest in certain exploration opportunities. Alternatively, to fund acquisitions, increase our rate of growth, develop our properties or pay for higher service costs, we may decide to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments, the sale of non-strategic assets, the borrowing of funds or otherwise to meet any increase in capital spending. If we are unable to raise additional capital from available sources at acceptable terms, our business, financial condition and future results of operations could be adversely affected.

Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of Operational and Financial Risk, with Many Uncertainties That Could Adversely Affect Our Business.

Exploring for and developing hydrocarbon reserves involves a high degree of operational and financial risk, which precludes us from definitively predicting the costs involved and time required to reach certain objectives. Our drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation before they can be drilled. The budgeted costs of planning, drilling, completing and operating wells are often exceeded and such costs can increase significantly due to various complications that may arise during drilling, completion and operation. Before a well is spud, we may incur significant geological and geophysical (seismic) costs, which are incurred whether or not a well eventually produces commercial quantities of hydrocarbons, or is drilled at all. Exploration wells bear a much greater risk of loss than development wells. The analogies we draw from available data from other wells, more fully explored locations or producing fields may not be applicable to our drilling locations. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our operations as proposed and could be forced to modify our drilling plans accordingly.

If we decide to drill a certain location, there is a risk that no commercially productive oil or natural gas reservoirs will be found or produced. We may drill or participate in new wells that are not productive. We may drill wells that are productive, but that do not produce sufficient net revenues to return a profit after drilling, operating and other costs. There is no way to affirmatively determine in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover exploration, drilling and completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production and reserves from, or abandonment of, the well. The productivity and profitability of a well may be negatively affected by a number of additional factors, including the following:

- general economic and industry conditions, including the prices received for oil and natural gas;
- shortages of, or delays in, obtaining equipment, including hydraulic fracturing equipment, and qualified personnel;
- potential drainage by operators on adjacent properties;
- loss of or damage to oilfield development and service tools;
- accidents, equipment failures or mechanical problems;
- problems with title to the underlying properties;
- increases in severance taxes;
- adverse weather conditions that delay drilling activities or cause producing wells to be shut in;
- domestic and foreign governmental regulations; and
- proximity to and capacity of gathering, processing and transportation facilities.

If we do not drill productive and profitable wells in the future, our business, financial condition, results of operations, cash flows and reserves could be materially and adversely affected.

We May Incur Additional Indebtedness Which Could Reduce Our Financial Flexibility, Increase Interest Expense and Adversely Impact Our Operations and Our Unit Costs.

At February 27, 2015, following the closing of the HEYCO Merger, we had available borrowings of approximately $54.4 million under our Credit Agreement (after giving effect to outstanding letters of credit). Our borrowing base is determined semi-annually by our lenders based primarily on the estimated value of our existing and future oil and natural gas reserves, but both we and our lenders can request one unscheduled redetermination between scheduled redetermination dates. Our Credit Agreement is secured by substantially all of our interests in our oil and natural gas properties, other than those properties acquired in the HEYCO Merger (which properties separately secure the approximately $12.0 million in indebtedness we assumed in the HEYCO Merger), and contains covenants restricting our ability to incur additional indebtedness, sell assets, pay dividends and make certain investments. Since the borrowing base is subject to periodic redeterminations, if a redetermination resulted in a lower borrowing base, we could be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or repay the deficit in equal installments over a period of six months. If we are required to do so, we may not have sufficient funds to fully make such repayments.

In the future, we may incur significant amounts of additional indebtedness, including under our Credit Agreement, in order to fund acquisitions, develop our properties or invest in certain exploration opportunities. Interest rates on such future indebtedness may be higher than current levels, causing our financing costs to increase accordingly.

A high level of indebtedness could affect our operations in several ways, including the following:

- requiring a significant portion of our cash flows to be used for servicing our indebtedness;
- increasing our vulnerability to general adverse economic and industry conditions;
- placing us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our level of indebtedness may prevent us from pursuing;
- restricting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate or other purposes; and
- increasing the risk that we may default on our debt obligations.

Our Operations Are Subject to Operational Hazards and Unforeseen Interruptions for Which We May Not Be Adequately Insured.

There are numerous operational hazards inherent in oil and natural gas exploration, development, production and gathering, including:

- natural disasters;
- adverse weather conditions;
- loss of drilling fluid circulation;
- blowouts where oil or natural gas flows uncontrolled at a wellhead;
- cratering or collapse of the formation;
- pipe or cement leaks, failures or casing collapses;
- fires or explosions;
- releases of hazardous substances or other waste materials that cause environmental damage;
- pressures or irregularities in formations; and
- equipment failures or accidents.

In addition, there is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions to air and water, the underground injection or other disposal of our wastes, the use of hydraulic fracturing fluids and historical industry operations and waste disposal practices. Any of these or other similar occurrences could result in the disruption or impairment of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution and substantial revenue losses. The location of our wells, gathering systems, pipelines and other facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. Pollution and environmental risks generally are not fully insurable. In addition, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable prices or on commercially reasonable terms. Changes in the insurance markets due to various factors may make it more difficult for us to obtain certain types of coverage in the future. As a result, we may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and the insurance coverage we do obtain may not cover certain hazards or all potential losses that are currently covered, and may be subject to large deductibles. Losses and liabilities from uninsured and underinsured events and delays in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Because Our Reserves and Production Are Concentrated in a Few Core Areas, Problems in Production and Markets Relating to a Particular Area Could Have a Material Impact on Our Business.

Almost all of our current oil and natural gas production and our proved reserves are attributable to our properties in the Eagle Ford shale in South Texas, the Permian Basin in Southeast New Mexico and West Texas and the Haynesville shale in Northwest Louisiana and East Texas. For the year ended December 31, 2014, approximately 65% of our total oil and natural gas production, including approximately 85% of our average daily oil production, was attributable to our properties in South Texas and approximately 11% of our total oil and natural gas production, including approximately 14% of our average daily oil production, was attributable to our properties in the Permian Basin. At December 31, 2014, approximately 58% of the PV-10 of our total proved oil and natural gas reserves and approximately 67% of our total proved oil reserves were attributable to our properties in South Texas, primarily in the Eagle Ford shale, and approximately 24% of the PV-10 of our total proved oil and natural gas reserves and approximately 33% of our total proved oil reserves were attributable to our properties in the Permian Basin. We expect that most of our operations in 2015 will be primarily in the Permian Basin. We expect to direct approximately 70% of our 2015 capital expenditures to further delineating and developing our acreage position in the Permian Basin in Southeast New Mexico and West Texas and 26% of our 2015 capital expenditures to further developing our acreage position in the Eagle Ford shale in South Texas.

The industry focus on the Eagle Ford shale and the Permian Basin may adversely impact our ability to transport and process our oil and natural gas production due to significant competition for gathering systems, pipelines, processing facilities and oil and condensate trucking operations. For example, infrastructure 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. Even though we have entered into a firm five-year natural gas processing and transportation agreement covering the anticipated natural gas production from a significant portion of our Eagle Ford shale acreage in South Texas, due to the concentration of our operations we may be disproportionately exposed to the impact of delays or interruptions of production from our wells in our operating areas caused by transportation capacity constraints or interruptions, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions or plant closures for scheduled maintenance.

Our operations may also be adversely affected by weather conditions and events such as hurricanes, tropical storms and inclement winter weather, resulting in delays in drilling and completions, damage to facilities and equipment and the inability to receive equipment or access personnel and products at affected job sites in a timely manner. For example, during the fourth quarters of 2013 and 2014, the Permian Basin experienced severe winter weather that impacted many operators. In particular, the weather conditions and freezing temperatures resulted in power outages, curtailments in trucking, delays in drilling and completion of wells and other production constraints. In the third quarter of 2014, certain areas of the Permian Basin experienced severe flooding that impacted our operations as well as many other operators in the area, resulting in delays in drilling, completing and initiating production on certain wells. As we increase our operations and production in the Permian Basin, we may increasingly face these and other challenges posed by severe weather.

Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. For example, our operations in the Permian Basin are subject to particular restrictions on drilling activities based on environmental sensitivities and requirements and potash mining operations. Such delays, interruptions or restrictions could have a material adverse effect on our financial condition, results of operations and cash flows.

The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows.

Shortages or the high cost of drilling rigs, completion equipment and services, personnel or supplies, including sand and other proppants, could delay or adversely affect our operations. When drilling activity in the United States increases, associated costs typically also increase, including those costs related to drilling rigs, equipment, supplies, including sand and other proppants, and personnel and the services and products of other industry vendors. These costs may increase, and necessary equipment, supplies and services may become unavailable to us at economical prices. Should this increase in costs occur, we may delay drilling activities, which may limit our ability to establish and replace reserves, or we may incur these higher costs, which may negatively affect our business, financial condition, results of operations and cash flows.

In addition, the demand for hydraulic fracturing services from time to time exceeds the availability of fracturing equipment and crews across the industry and in certain operating areas in particular. The accelerated wear and tear of hydraulic

Table of Contents

fracturing equipment due to its deployment in unconventional oil and natural gas fields characterized by longer lateral lengths and larger numbers of fracturing stages could further amplify such an equipment and crew shortage. If demand for fracturing services were to increase or the supply of fracturing equipment and crews were to decrease, higher costs could result which could adversely affect our business, financial condition, results of operations and cash flows.

If We Are Unable to Acquire Adequate Supplies of Water for Our Drilling and Hydraulic Fracturing Operations or Are Unable to Dispose of the Water We Use at a Reasonable Cost and Pursuant to Applicable Environmental Rules, Our Ability to Produce Oil and Natural Gas Commercially and in Commercial Quantities Could Be Impaired.

We use a substantial amount of water in our drilling and hydraulic fracturing operations. Our inability to obtain sufficient amounts of water at reasonable prices, or treat and dispose of water after drilling and hydraulic fracturing, could adversely impact our operations. In recent years, Southeast New Mexico and West Texas have experienced severe drought. As a result, we may experience difficulty in securing the necessary volumes of water for 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 and production of oil and natural gas. Furthermore, future environmental regulations and permitting 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 business, financial condition, results of operations and cash flows.

Unless We Replace Our Oil and Natural Gas Reserves, Our Reserves and Production Will Decline, Which Would Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The rate of production from our oil and natural gas properties declines as our reserves are depleted. Our future oil and natural gas reserves and production and, therefore, our income and cash flow, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional oil and natural gas producing properties. We are currently focusing primarily on increasing our production and reserves from the Permian Basin and the Eagle Ford shale, areas in which our competitors have been active. As a result of this activity, we may have difficulty expanding our current production or acquiring new properties in these areas and may experience such difficulty in other areas in the future. During periods of low oil and/or natural gas prices, existing reserves may no longer be economic, and it will become more difficult to raise the capital necessary to finance expansion activities. If we are unable to replace our current and future production, our reserves will decrease, and our business, financial condition, results of operations and cash flows would be adversely affected.

Our Oil and Natural Gas Reserves Are Estimated and May Not Reflect the Actual Volumes of Oil and Natural Gas We Will Recover, and Significant Inaccuracies in These Reserves Estimates or Underlying Assumptions Will Materially Affect the Quantities and Present Value of Our Reserves.

The process of estimating accumulations of oil and natural gas is complex and inexact, due to numerous inherent uncertainties. This process relies on interpretations of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. This process also requires certain economic assumptions related to, among other things, oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserves estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the judgment of the persons preparing the estimate; and
- the accuracy of the assumptions used.

The accuracy of any estimates of proved oil and natural gas reserves generally increases with the length of production history. Due to the limited production history of many of our properties, the estimates of future production associated with these properties may be subject to greater variance to actual production than would be the case with properties having a longer production history. As our wells produce over time and more data becomes available, the estimated proved reserves will be redetermined on at least an annual basis and may be adjusted to reflect new information based upon our actual production history, results of exploration and development, prevailing oil and natural gas prices and other factors.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from our estimates. It is possible that future production declines in our wells may be greater than we have estimated. Any significant variance to our estimates could materially affect the quantities and present value of our reserves.

Table of Contents

The Calculated Present Value of Future Net Revenues from Our Proved Oil and Natural Gas Reserves Will Not Necessarily Be the Same as the Current Market Value of Our Estimated Oil and Natural Gas Reserves.

It should not be assumed that the present value of future net cash flows included in this Annual Report on Form 10-K is the current market value of our estimated proved oil and natural gas reserves. As required by SEC rules and regulations, the estimated discounted future net cash flows from proved oil and natural gas reserves are based on current costs held constant over time without escalation and on commodity prices using an unweighted arithmetic average of first-day-of-the-month index prices, appropriately adjusted, for the 12-month period immediately preceding the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs used for these estimates and will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual costs and timing of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under U.S. generally accepted accounting principles, or GAAP, is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and natural gas industry in general.

Approximately 61% of Our Total Proved Reserves at December 31, 2014 Consisted of Undeveloped and Developed Non-Producing Reserves, and Those Reserves May Not Ultimately Be Developed or Produced.

At December 31, 2014, approximately 55% of our total proved reserves were undeveloped and approximately 6% were developed non-producing. Our undeveloped and/or developed non-producing reserves may never be developed or produced or such reserves may not be developed or produced within the time periods we have projected or at the costs we have estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves would reduce the present value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves, resulting in some projects becoming uneconomical and reducing our total proved reserves. In addition, delays in the development of reserves or declines in the oil and/or natural gas prices used to estimate proved reserves in the future could cause us to have to reclassify a portion of our proved reserves as unproved reserves. Any reduction in our proved reserves caused by the reclassification of undeveloped or developed non-producing reserves could materially affect our business, financial condition, results of operations and cash flows.

Our Identified Drilling Locations Are Scheduled over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling.

Our management team has identified and scheduled drilling locations in our operating areas over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including assessment of risks, costs, drilling results, oil and natural gas prices, the availability of equipment and capital, approval by regulators, lease terms and seasonal conditions. The final determination on whether to drill any of these locations will be dependent upon the factors described elsewhere in this Annual Report on Form 10-K as well as, to some degree, the results of our drilling activities with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe, or at all, or if we will be able to economically produce hydrocarbons from these or any other potential drilling locations. Our actual drilling activities may be materially different from our current expectations, which could adversely affect our business, financial condition, results of operations and cash flows.

Certain of Our Unproved and Unevaluated Acreage Is Subject to Leases That Will Expire over the Next Several Years Unless Production Is Established on Units Containing the Acreage.

At December 31, 2014, we had leasehold interests in approximately 31,100 net acres across all of our areas of interest that are not currently held by production and are subject to leases with primary or renewed terms that expire prior to December 31, 2016. Unless we establish production, generally in paying quantities, on units containing these leases during their terms or we renew such leases, these leases will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third party leases may have been taken and could become immediately effective if our leases expire. If our leases expire or we are unable to renew such leases, we will lose our right to develop the related properties. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business, financial condition, results of operations and cash flows.

Table of Contents

The 2-D and 3-D Seismic Data and Other Advanced Technologies We Use Cannot Eliminate Exploration Risk, Which Could Limit Our Ability to Replace and Grow Our Reserves and Materially and Adversely Affect Our Results of Operations and Cash Flows.

We employ visualization and 2-D and 3-D seismic images to assist us in exploration and development activities where applicable. These techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. We could incur losses by drilling unproductive wells based on these technologies. Furthermore, seismic and geological data can be expensive to license or obtain and we may not be able to license or obtain such data at an acceptable cost. Poor results from our exploration activities could limit our ability to replace and grow reserves and adversely affect our business, financial condition, results of operations and cash flows.

Competition in the Oil and Natural Gas Industry Is Intense, Making It More Difficult for Us to Acquire Properties, Market Oil and Natural Gas and Secure Trained Personnel.

Competition is intense in virtually all facets of our business. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased in recent years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our Competitors May Use Superior Technology and Data Resources That We May Be Unable to Afford or That Would Require a Costly Investment by Us in Order to Compete with Them More Effectively.

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products, equipment and services using new technologies and databases. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, many of our competitors will 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 cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we will use or that we may implement in the future may become obsolete, and we may be adversely affected.

Strategic Relationships upon Which We May Rely Are Subject to Change, Which May Diminish Our Ability to Conduct Our Operations.

Our ability to explore, develop and produce oil and natural gas resources successfully and acquire oil and natural gas interests and acreage depends on our developing and maintaining close working relationships with industry participants and on our ability to select and evaluate suitable acquisition opportunities in a highly competitive environment. These relationships are subject to change and, if they do, our ability to grow may be impaired.

To develop our business, we will endeavor to use the business relationships of our management, board and special board advisors to enter into strategic relationships, which may take the form of contractual arrangements with other oil and natural gas companies, including those that supply equipment and other resources that we expect to use in our business, as well as certain financial institutions. We may not be able to establish these strategic relationships, or if established, we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to incur in order to fulfill our obligations to these partners or maintain our relationships. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

The Marketability of Our Production Is Dependent upon Oil and Natural Gas Gathering, Processing and Transportation Facilities Owned and Operated by Third Parties, and the Unavailability of Satisfactory Oil and Natural Gas Gathering, Processing and Transportation Arrangements Would Have a Material Adverse Effect on Our Revenue.

The unavailability of satisfactory oil, natural gas and natural gas liquids gathering, processing and transportation arrangements may hinder our access to oil, natural gas and natural gas liquids markets or delay production from our wells. The availability of a ready market for our oil, natural gas and natural gas liquids production depends on a number of factors, including the demand for, and supply of, oil, natural gas and natural gas liquids 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, processing facilities and oil and condensate trucking operations owned and operated by third parties. Our failure to obtain these services on acceptable terms could materially harm our business. In addition, certain of these gathering systems, pipelines and processing facilities, particularly in the Permian Basin, may be outdated or in need of repair and subject to higher rates of line loss, failure and breakdown.

We may be required to shut in wells for lack of a market or because of inadequate or unavailable pipelines, gathering systems or trucking capacity. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver our production to market. 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. In addition, if we are unable to market our production we may be required to flare natural gas occasionally, which would decrease the volumes sold from our wells.

The disruption of third party facilities due to maintenance, weather or other factors could negatively impact our ability to market and deliver our oil, natural gas and natural gas liquids. The third parties control when or if such facilities are restored and what prices will be charged. In the past, we have experienced pipeline and natural gas processing interruptions and capacity and infrastructure constraints associated with natural gas production, which has, among other things, required us to flare natural gas occasionally. While we have entered into a firm five-year natural gas processing and transportation agreement covering the anticipated natural gas production from a significant portion of our Eagle Ford shale acreage in South Texas, no assurance can be given that this agreement will alleviate these issues completely, and we may be required to pay deficiency payments under this agreement if we do not meet the thermal quantity transportation and processing commitments under this agreement. We may experience similar interruptions and processing capacity constraints as we continue to explore and develop our Wolfcamp and Bone Spring plays in the Permian Basin in 2015. If we were required to shut in our production for long periods of time due to pipeline interruptions or lack of processing facilities or capacity of these facilities, it would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Financial Difficulties Encountered by Our Oil and Natural Gas Purchasers, Third Party Operators or Other Third Parties Could Decrease Our Cash Flows from Operations and Adversely Affect the Exploration and Development of Our Prospects and Assets.

We derive most of our revenues from the sale of our oil, natural gas and natural gas liquids to unaffiliated third party purchasers, independent marketing companies and midstream companies. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. Any delays in payments from our purchasers caused by financial problems encountered by them will have an immediate negative effect on our results of operations and cash flows.

Liquidity and cash flow problems encountered by our working interest co-owners or the third party operators of our non-operated properties may prevent or delay the drilling of a well or the development of a project. Our working interest co-owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farmout party, we would have to find a new farmout party or obtain alternative funding in order to complete the exploration and development of the prospects subject to a farmout agreement. In the case of a working interest owner, we could be required to pay the working interest owner’s share of the project costs. If we are not able to obtain the capital necessary to fund either of these contingencies or find a new farmout party, our results of operations and cash flows could be negatively affected.

Gathering, Processing and Transportation Services Are Subject to Complex Federal, State and Other Laws that Could Adversely Affect the Cost, Manner or Feasibility of Conducting Our Business.

The operations of the third parties on whom we rely for gathering, processing and transportation services, and, to a lesser extent, affiliate companies providing limited amounts of such services, are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the parties on whom we rely could have a material adverse effect on our business, financial condition, results of operations and cash flows. See “Business — Regulation.”

We Have Limited Control over Activities on Properties We Do Not Operate.

We are not the operator on some of our properties, particularly in the Haynesville shale. As a result of our sale of certain assets to Chesapeake in 2008, we do not operate one of our most significant natural gas assets in the Haynesville shale. We also have other non-operated acreage positions in Northwest Louisiana, South Texas, Southeast New Mexico and West Texas. Because we are not the operator for these properties, our ability to exercise influence over the operations of these properties or their associated costs is limited. Our dependence on the operators and other working interest owners of these projects and our

Table of Contents

limited ability to influence operations and associated costs, or control the risks, could materially and adversely affect the drilling results, reserves and future cash flows from these properties. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors, including:

- timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- the rate of production of reserves, if any;
- approval of other participants in drilling wells; and
- selection and implementation or execution of technology.

In areas where we do not have the right to propose the drilling of wells, we may have limited influence on when, how and at what pace our properties in those areas are developed. Further, the operators of those properties may experience financial problems in the future or may sell their rights to another operator not of our choosing, both of which could limit our ability to develop and monetize the underlying oil or natural gas reserves. In addition, the operators of these properties may elect to curtail the oil or natural gas production or to shut in the wells on these properties during periods of low oil or natural gas prices, and we may receive less than anticipated or no production and associated revenues from these properties until the operator elects to return them to production.

A Component of Our Growth May Come through Acquisitions, and Our Failure to Identify or Complete Future Acquisitions Successfully Could Reduce Our Earnings and Hamper Our Growth.

We may be unable to identify properties for acquisition or to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. The completion and pursuit of acquisitions may be dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to grow through acquisitions will require us to continue to invest in operations and financial and management information systems and to attract, retain, motivate and effectively manage our employees.

In addition, we may be unable to successfully integrate any potential acquisitions into our existing operations. The inability to manage the integration of acquisitions, including the HEYCO Merger, effectively could reduce our focus on subsequent acquisitions and current operations, and could negatively impact our results of operations and growth potential. Members of our senior management team may be required to devote considerable amounts of time to the integration process, including with respect to the HEYCO Merger, which will decrease the time they will have to manage our business.

Furthermore, our decision to acquire properties that are substantially different in operating or geologic characteristics or geographic locations from areas with which our staff is familiar may impact our productivity in such areas. Our financial condition, results of operations and cash flows may fluctuate significantly from period to period as a result of the completion of significant acquisitions during particular periods. If we are not successful in identifying or acquiring any material property interests, our earnings could be reduced and our growth could be restricted.

We may engage in bidding and negotiation to complete successful acquisitions. We may be required to alter or increase substantially our capitalization to finance these acquisitions through the use of cash on hand, the issuance of debt or equity securities, the sale of production payments, the sale of non-strategic assets, the borrowing of funds or otherwise. Our Credit Agreement includes covenants limiting our ability to incur additional debt. If we were to proceed with one or more acquisitions involving the issuance of our common stock, our shareholders would suffer dilution of their interests.

We May be Unsuccessful in Combining HEYCO's Business with Our Existing Business.

The success of the HEYCO Merger will depend, in part, on our ability to realize the anticipated benefits and synergies from combining our business and existing asset base with the business of HEYCO and the assets obtained in the HEYCO Merger. To realize these anticipated benefits, the businesses must be successfully integrated. If we are not able to achieve these objectives, or we are not able to achieve these objectives on a timely basis, the anticipated benefits of the HEYCO Merger may not be realized fully or at all. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the HEYCO Merger. These integration difficulties could have a material adverse effect on our business, financial condition and results of operations.

We May Purchase Oil and Natural Gas Properties with Liabilities or Risks That We Did Not Know About or That We Did Not Assess Correctly, and, as a Result, We Could Be Subject to Liabilities That Could Adversely Affect Our Results of Operations.

Before acquiring oil and natural gas properties, we estimate the reserves, future oil and natural gas prices, operating costs, potential environmental liabilities and other factors relating to the properties. However, our review involves many assumptions and estimates, and their accuracy is inherently uncertain. As a result, we may not discover all existing or potential problems associated with the properties we buy. We may not become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not generally perform inspections on every well or property, and we may not be able to observe mechanical and environmental problems even when we conduct an inspection. The seller may not be willing or financially able to give us contractual protection against any identified problems, and we may decide to assume environmental and other liabilities in connection with properties we acquire. If we acquire properties with risks or liabilities we did not know about or that we did not assess correctly, our financial condition, results of operations and cash flows could be adversely affected as we settle claims and incur cleanup costs related to these liabilities.

We May Incur Losses or Costs as a Result of Title Deficiencies in the Properties in Which We Invest.

If an examination of the title history of a property that we have purchased reveals an oil and natural gas lease has been purchased in error from a person who is not the owner of the mineral interest desired or other title deficiencies, our interest would be worth less than what we paid or may be worthless. In such an instance, all or part of the amount paid for such oil and natural gas lease as well as all or part of any royalties paid pursuant to the terms of the lease prior to the discovery of the title defect would be lost.

It is not our practice in acquiring oil and natural gas leases, or undivided interests in oil and natural gas leases, to undergo the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease in all acquisitions. Rather, in certain acquisitions we rely upon the judgment of oil and natural gas lease brokers and/or landmen who perform the field work by examining records in the appropriate governmental office before attempting to acquire a lease on a specific mineral interest.

Prior to the drilling of an oil and natural gas well, however, it is standard industry practice for the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may adversely impact our ability to increase production and reserves. In the future, we may suffer a monetary loss from title defects or title failure. Additionally, unproved and unevaluated acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss which could adversely affect our financial condition, results of operations and cash flows.

We May Be Required to Write Down the Carrying Value of Our Proved Properties under Accounting Rules and These Write-Downs Could Adversely Affect Our Financial Condition.

There is a risk that we will be required to write down the carrying value of our oil and natural gas properties when oil or natural gas prices are low or are declining. In addition, non-cash write-downs may occur if we have:

- downward adjustments to our estimated proved reserves;
- increases in our estimates of development costs; or
- deterioration in our exploration and development results.

We periodically review the carrying value of our oil and natural gas properties under full-cost accounting rules. Under these rules, the net capitalized costs of oil and natural gas properties less related deferred income taxes may not exceed a cost center ceiling that is based on the present value, based on constant prices and costs projected forward from a single point in time, of estimated future after-tax net cash flows from proved reserves, discounted at 10%. If the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceed the cost center ceiling, we must charge the amount of this excess to operations in the period in which the excess occurs. We may not reverse write-downs even if prices increase in subsequent periods. Although uncertain future prices impact the ability to predict future full cost ceiling impairments, we do anticipate recognizing full-cost ceiling impairments in 2015, beginning as early as the first quarter of 2015. This conclusion is based on the historic prices for the last nine months of 2014 and the first two months of 2015 as well as the short-term pricing outlook. Although we can predict with relative certainty that we will recognize full-cost ceiling impairments in 2015, we are not able to reasonably estimate the amounts. A write-down does not affect net cash flows from operating activities, liquidity or capital resources, but it does reduce the book value of our net tangible assets, retained earnings and shareholders' equity and could lower the

value of our common stock.
Hedging Transactions, or the Lack Thereof, May Limit Our Potential Gains and Could Result in Financial Losses.
To manage our exposure to price risk, we, from time to time, enter into hedging arrangements, using primarily "costless collars" or "swaps" with respect to a portion of our future production. Costless collars provide us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially "costless" to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over the specified period, providing downside price protection. The goal of these and other hedges

Table of Contents

is to lock in a range of prices in the case of collars or a fixed price in the case of swaps so as to mitigate price volatility and increase the predictability of cash flows. These transactions limit our potential gains if oil, natural gas or natural gas liquids prices rise above the maximum price established by the call option and may offer protection if prices fall below the minimum price established by the put option only to the extent of the volumes then hedged.

In addition, hedging transactions may expose us to the risk of financial loss in certain other circumstances, including instances in which our production is less than expected or the counterparties to our put and call option or swap contracts fail to perform under the contracts. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair its ability to perform under the terms of the contracts. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform under contracts with us. Even if we do accurately predict sudden changes, our ability to mitigate that risk may be limited depending upon market conditions.

Furthermore, there may be times when we have not hedged our production when, in retrospect, it would have been advisable to do so. Decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and natural gas liquids prices, and we may not always employ the optimal hedging strategy. We may employ hedging strategies in the future that differ from those that we have used in the past, and neither the continued application of our current strategies nor our use of different hedging strategies may be successful. We currently have no hedges in place for oil, natural gas or natural gas liquids beyond 2015.

An Increase in the Differential between the NYMEX or Other Benchmark Prices of Oil and Natural Gas and the Wellhead Price We Receive for Our Production Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The prices that we receive for our oil and natural gas production sometimes reflect a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the benchmark prices and the prices we receive is called a differential. Increases in the differential between the benchmark prices for oil and natural gas and the wellhead prices we receive could adversely affect our business, financial condition, results of operations and cash flows. We do not have, and may not have in the future, any derivative contracts covering the amount of the basis differentials we experience in respect of our production. As such, we will be exposed to any increase in such differentials.

We Are Subject to Government Regulation and Liability, Including Complex Environmental Laws, Which Could Require Significant Expenditures.

The exploration, development, production, gathering, processing, transportation and sale of oil and natural gas in the United States are subject to many federal, state and local laws, rules and regulations, including complex environmental laws and regulations. Matters subject to regulation include discharge permits, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, taxation and environmental matters and health and safety criteria addressing worker protection. Under these laws and regulations, we may be required to make large expenditures that could materially adversely affect our financial condition, results of operations and cash flows. These expenditures could include payments for:

- personal injuries;
- property damage;
- containment and clean-up of oil and other spills;
- management and disposal of hazardous materials;
- remediation, clean-up costs and natural resource damages; and
- other environmental damages.

We do not believe that full insurance coverage for all potential damages is available at a reasonable cost. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, injunctive relief and/or the imposition of investigatory or other remedial obligations. Laws, rules and regulations protecting the environment have changed frequently and the changes often include increasingly stringent requirements. These laws, rules and regulations may impose liability on us for environmental damage and disposal of hazardous materials even if we were not negligent or at fault. We may also be found to be liable for the conduct of others or for acts that complied with applicable laws, rules or regulations at the time we performed those acts. These laws, rules and regulations are interpreted and enforced by numerous federal and state agencies. In addition, private parties, including the owners of properties upon which our wells are drilled or the owners of properties adjacent to or in close proximity to those properties, may also pursue legal actions against us based on alleged non-compliance with certain of these laws, rules and regulations.

Table of Contents

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact statements and/or plans of development before commencing exploration and production activities. Oil and natural gas operations in certain of our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. The designation of previously unprotected species as threatened or endangered species could prohibit drilling in certain of our operating areas, cause us to incur increased costs arising from species protection measures or result in limitations on our exploration and production activities, each of which could have an adverse impact on our ability to develop and produce our reserves.

We Are Subject to Federal, State and Local Taxes, and May Become Subject to New Taxes or Have Eliminated or Reduced Certain Federal Income Tax Deductions Currently Available with Respect to Oil and Natural Gas Exploration and Production Activities as a Result of Future Legislation, Which Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases may occur. In addition, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals.

Periodically, legislation is introduced to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for certain oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production or manufacturing activities and (iv) the increase in the amortization period for geological and geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas within the United States. President Obama has proposed sweeping changes in federal laws on the income taxation of small oil and natural gas exploration and production companies like ours. President Obama has proposed to eliminate allowing small oil and natural gas companies to deduct intangible drilling costs as incurred and percentage depletion. The passage of any legislation as a result of the budget proposals or any other similar change in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and natural gas exploration and production activities and could negatively impact our financial condition, results of operations and cash flows.

Federal and State Legislation and Regulatory Initiatives Relating to Hydraulic Fracturing Could Result in Increased Costs and Additional Operating Restrictions or Delays.

In past sessions, Congress has considered, but did not pass, legislation to amend the Safe Drinking Water Act, or SDWA, to remove the SDWA’s exemption granted to most hydraulic fracturing operations (other than operations using fluids containing diesel) and to require reporting and disclosure of chemicals used by oil and natural gas companies in the hydraulic fracturing process. The EPA recently issued SDWA permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. Hydraulic fracturing involves the injection of water, sand or other propping agents and chemicals under pressure into rock formations to stimulate oil and natural gas production. We routinely use hydraulic fracturing to complete wells in order to produce oil, natural gas and natural gas liquids from formations such as the Eagle Ford shale, the Wolfcamp and Bone Spring plays and the Haynesville shale, where we focus our operations. The EPA is conducting a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water and groundwater. A progress report was released in December 2012, with draft final results expected in early 2015. Consequently, even if federal legislation is not adopted soon or at all, the performance of the hydraulic fracturing study by the EPA could spur further action towards federal legislation and regulation of hydraulic fracturing or similar production operations. Also at the federal level, the BLM has proposed rules to regulate hydraulic fracturing on federal lands. Additionally, the EPA has issued an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act to develop regulations governing the disclosure of hydraulic fracturing chemicals.

In addition, a number of states and local regulatory authorities are considering or have implemented more stringent regulatory requirements applicable to hydraulic fracturing, including bans/moratoria on drilling and effectively prohibit further production of oil and natural gas through the use of hydraulic fracturing or similar operations. For example, in December 2014 New York announced a moratorium on high volume fracturing activities combined with horizontal drilling following the issuance of a study regarding the safety of hydraulic fracturing. Certain communities in Colorado have also enacted bans on hydraulic fracturing. Voters in the city of Denton, Texas also recently approved a moratorium on hydraulic fracturing. These actions are the subject of legal challenges. Texas and Wyoming have adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process. These restrictions and regulations could increase our costs of compliance and doing business.

Table of Contents

The adoption of new laws or regulations imposing reporting obligations on, or otherwise limiting or prohibiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in unconventional plays. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, hydraulic fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in cost, which could adversely affect our business and results of operations.

Legislation or Regulations Restricting Emissions of Greenhouse Gases Could Result in Increased Operating Costs and Reduced Demand for the Oil, Natural Gas and Natural Gas Liquids We Produce while the Physical Effects of Climate Change Could Disrupt Our Production and Cause Us to Incur Significant Costs in Preparing for or Responding to Those Effects.

The EPA has published its final findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Accordingly, the EPA has adopted rules under the CAA for the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. The EPA has adopted a multi-tiered approach to this permitting, with the largest sources first subject to permitting. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA released a final rule that expands its rule on reporting of greenhouse gas emissions to include owners and operators of petroleum and natural gas systems. Monitoring of those newly covered emissions commenced on January 1, 2011, with the first annual reports filed in 2012.

In an interpretative guidance on climate change disclosures, the SEC indicated that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland and water availability and quality. If such effects were to occur, there is the potential for our exploration and production operations to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. In addition, our hydraulic fracturing operations require large amounts of water. See "—If We Are Unable to Acquire Adequate Supplies of Water for Our Drilling and Hydraulic Fracturing Operations or Are Unable to Dispose of the Water We Use at a Reasonable Cost and Pursuant to Applicable Environmental Rules, Our Ability to Produce Oil and Natural Gas Commercially and in Commercial Quantities Could Be Impaired." Should climate change or other drought conditions occur, our ability to obtain water of a sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

New Regulations on All Emissions from Our Operations Could Cause Us to Incur Significant Costs.

On April 17, 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards required owners/operators to reduce volatile organic compound, or VOC, emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. Further, the finalized regulations also established specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. In December 2014, the EPA issued finalized additional amendments to these rules that, among other things, distinguished between multiple flowback stages during completion of hydraulically fractured wells and clarified that storage tanks permanently removed from service are not affected by any requirements. These rules have required changes to our operations, including the installation of new equipment to control emissions. We continue to evaluate the effect these rules have on our business and operations, which are not anticipated to be materially impacted. Further, in 2012, seven states sued the EPA to compel the agency to make a determination as to whether standards of performance limiting methane emissions from oil and natural gas sources is appropriate and, if so, to promulgate performance standards for methane emissions from existing oil and natural gas sources. In April 2014, the EPA released a set of five white papers analyzing methane emissions from the industry. In January 2015, EPA announced plans to issue a rule in summer 2015 governing methane emissions from the oil and natural gas industry. The Bureau of Land Management (BLM) is also expected to address methane emissions from the oil and natural gas industry on federal lands. These rules could increase our operating costs and have a material adverse effect on our business and operations.

Table of Contents

The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. There were attempts at comprehensive federal legislation establishing a cap and trade program, but that legislation did not pass. Further, various states have considered or adopted legislation that seeks to control or reduce emissions of greenhouse gases from a wide range of sources. Any such legislation could adversely affect demand for the oil, natural gas and natural gas liquids that we produce.

A Change in the Jurisdictional Characterization of Some of Our Assets by FERC or a Change in Policy by It May Result in Increased Regulation of Our Assets, Which May Cause Our Revenues to Decline and Operating Expenses to Increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. A change in the jurisdictional characterization by FERC, the courts or Congress or a change in policy by FERC or Congress may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Should We Fail to Comply with All Applicable FERC-Administered Statutes, Rules, Regulations and Orders, We Could Be Subject to Substantial Penalties and Fines.

Under the Energy Policy Act, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1.0 million per day for each violation and disgorgement of profits associated with any violation. The nature of our gathering facilities is such that we have not yet been regulated by FERC as a natural gas company subject to the provisions of the NGA. It is possible, however, that laws, rules and regulations pertaining to those and other matters may be considered or adopted by FERC or Congress from time to time. Failure to comply with those laws, rules and regulations in the future could subject us to civil penalty liability.

The Derivatives Legislation Adopted by Congress Could Have an Adverse Impact on Our Ability to Hedge Risks Associated with Our Business.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which is intended to modernize and protect the integrity of the U.S. financial system. The Dodd-Frank Act, among other things, establishes federal oversight and regulation of certain derivative products, including commodity hedges of the type we use. The Dodd-Frank Act requires the Commodity Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. The Dodd-Frank Act could also result in additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future.

As a result, it is difficult to anticipate the overall impact of the Dodd-Frank Act on our ability or willingness to continue entering into and maintaining such commodity hedges and the terms thereof. Based upon the limited assessments we are able to make with respect to the Dodd-Frank Act, there is the possibility that the Dodd-Frank Act could have a substantial and adverse impact on our ability to enter into and maintain these commodity hedges.

If these types of commodity hedges become unavailable or uneconomic, our commodity price risk could increase, which would increase the volatility of revenues and may decrease the amount of credit available to us. Any limitations or changes in our use of derivative arrangements could also materially affect our cash flows, which could adversely affect our ability to make capital expenditures.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

Any of these consequences could have a material adverse effect on our business, financial condition and results of operations.

We May Have Difficulty Managing Growth in Our Business, Which Could Have a Material Adverse Effect on Our Business, Financial Condition, Results of Operations and Cash Flows and Our Ability to Execute Our Business Plan in a Timely Fashion.

Because of our size, growth in accordance with our business plans, if achieved, will place a significant strain on our financial, technical, operational and management resources. As and when we expand our activities, including any increase in oil exploration, development and production, and any increase in the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the inability to recruit and retain experienced managers, geoscientists, petroleum engineers, landmen, attorneys and financial and accounting professionals, could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to execute our business plan in a timely fashion.

Our Success Depends, to a Large Extent, on Our Ability to Retain Our Key Personnel, Including Our Chairman and Chief Executive Officer, Management and Technical Team, the Members of Our Board of Directors and Our Special Board Advisors, and the Loss of Any Key Personnel, Board Member or Special Board Advisor Could Disrupt Our Business Operations.

Investors in our common stock must rely upon the ability, expertise, judgment and discretion of our management and the success of our technical team in identifying, evaluating and developing prospects and reserves. Our performance and success are dependent to a large extent on the efforts and continued employment of our management and technical personnel, including our Chairman and Chief Executive Officer, Joseph Wm. Foran. We do not believe that they could be quickly replaced with personnel of equal experience and capabilities, and their successors may not be as effective. We have entered into employment agreements with Mr. Foran and other key personnel. However, these employment agreements do not ensure that these individuals will remain in our employment. If Mr. Foran or other key personnel resign or become unable to continue in their present roles and if they are not adequately replaced, our business operations could be adversely affected. With the exception of Mr. Foran, we do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We have an active Board of Directors that meets at least quarterly throughout the year and is closely involved in our business and the determination of our operational strategies. Members of our Board of Directors work closely with management to identify potential prospects, acquisitions and areas for further development. Certain of our directors have been involved with us since our inception and have a deep understanding of our operations and culture. If any of our directors resign or become unable to continue in their present role, it may be difficult to find replacements with the same knowledge and experience and, as a result, our operations may be adversely affected.

In addition, our board consults regularly with our special advisors regarding our business and the evaluation, exploration, engineering and development of our prospects. Due to the knowledge and experience of our special advisors, they play a key role in our multi-disciplined approach to making decisions regarding prospects, acquisitions and development. If any of our special advisors resign or become unable to continue in their present role, our operations may be adversely affected.

A Cyber Incident Could Occur and Result in Information Theft, Data Corruption, Operational Disruption or Financial Loss.

The oil and natural gas industry is dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to, among other things, estimate oil and natural gas reserves quantities, plan, execute and analyze drilling, completion and production operations and data, process and record financial and operating data and communicate with employees, shareholders, royalty owners and other third-party industry participants.

While we have not experienced any material losses due to cyber attacks, we may suffer such losses in the future. If our systems for protecting against cyber incidents prove to be insufficient, we could be adversely affected by unauthorized access to our proprietary information which could lead to data corruption, communication interruption, exposure of confidential or proprietary information, operational disruptions or financial loss. As cyber threats continue to evolve, we may be required to expend additional resources to continue to modify and enhance our protective systems or to investigate and remediate any vulnerabilities.

Risks Relating to Our Common Stock and Preferred Stock

The Price of Our Common Stock Has Fluctuated Substantially and May Fluctuate Substantially in the Future.

Our stock price has experienced volatility and could vary significantly as a result of a number of factors. In 2014, our stock price fluctuated between a high of $29.94 and a low of $14.08. In the future, the trading volume of our common stock may continue to fluctuate and cause significant price variations to occur. In the event of a drop in the market price of our

Table of Contents

common stock, you could lose a substantial part or all of your investment in our common stock. In addition, the stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.
Factors that could affect our stock price or result in fluctuations in the market price or trading volume of our common stock include:

- our actual or anticipated operating and financial performance and drilling locations, including oil and natural gas reserves estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and cash flows, or those of companies that are perceived to be similar to us;
- changes in revenue, cash flows or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- announcement or consummation of acquisitions or dispositions by us;
- public reaction to our press releases, announcements and filings with the SEC;
- sales of our common stock by us or shareholders, or the perception that such sales may occur;
- general financial market conditions and oil and natural gas industry market conditions, including fluctuations in commodity prices;
- the realization of any of the risk factors presented in this Annual Report on Form 10-K;
- the recruitment or departure of key personnel;
- commencement of or involvement in litigation;
- the prices of oil, natural gas and natural gas liquids;
- the success of our exploration and development operations, and the marketing of any oil, natural gas and natural gas liquids we produce;
- changes in market valuations of companies similar to ours; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

If We Fail to Maintain Effective Internal Control over Financial Reporting in the Future, Our Ability to Accurately Report Our Financial Results Could Be Adversely Affected.

As a public company with listed equity securities, we are required to comply with laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE. Complying with these statutes, regulations and requirements is difficult and occupies a significant amount of time of our Board of Directors and management and has significantly increased our costs and expenses.

Pursuant to the Sarbanes-Oxley Act, we are required to maintain internal controls over financial reporting. Our efforts to maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future and comply with the certification and reporting obligations under Sections 302 and 404 of the Sarbanes-Oxley Act. Our management does not expect that our internal controls and disclosure controls will prevent all possible error or all fraud. Further, our remediation efforts may not enable us to avoid material weaknesses in the future. Any failure to maintain effective controls could result in material misstatements that are not prevented or detected and corrected on a timely basis, which could potentially subject us to sanction or investigation by the SEC, the NYSE or other regulatory authorities. Ineffective internal controls could also cause investors to lose confidence in our reported financial information and adversely affect our business and our stock price.

We Do Not Presently Intend to Pay Any Cash Dividends on or Repurchase Any Shares of Our Common Stock.

We do not presently intend to pay any cash dividends on or repurchase any shares of our common stock. Any payment of future dividends will be at the discretion of our Board of Directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applicable to the payment of dividends and other considerations that our Board of Directors deems relevant. Cash dividend payments in the future may only be made out of legally available funds and, if we experience substantial losses, such funds may not be available. Any future cash dividends paid to holders of our common stock will also be owed to the holders of our Series A Preferred Stock on an as-converted basis. In addition, certain covenants in our Credit Agreement may limit our ability to pay dividends or repurchase shares of our common stock. Accordingly, you may have to sell some or all of your common stock in order to

Table of Contents

generate cash flow from your investment, and there is no guarantee that the price of our common stock will exceed the price you paid.

Future Sales of Shares of Our Common Stock by Existing Shareholders and Future Offerings of Our Common Stock by Us Could Depress the Price of Our Common Stock.

The market price of our common stock could decline as a result of sales of a large number of shares of our common stock in the market, including shares of preferred stock convertible into common stock, and the perception that these sales could occur may also depress the market price of our common stock. If our existing shareholders sell, or indicate an intent to sell, substantial amounts of our common stock in the public market, the trading price of our common stock could decline significantly. Sales of our common stock may make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. These sales could also cause our stock price to decrease and make it more difficult for you to sell shares of our common stock.

We may also sell or issue additional shares of common stock or securities convertible into common stock in public or private offerings or in connection with acquisitions, such as our Series A Preferred Stock issued in the HEYCO Merger. We cannot predict the size of future issuances of our common stock or convertible securities or the effect, if any, that future issuances and sales of shares of our common stock or convertible securities would have on the market price of our common stock.

Provisions of Our Certificate of Formation, Bylaws and Texas Law May Have Anti-Takeover Effects That Could Prevent a Change in Control Even if It Might Be Beneficial to Our Shareholders.

Our certificate of formation and bylaws contain certain provisions that may discourage, delay or prevent a merger or acquisition that our shareholders may consider favorable. These provisions include:

- authorization for our Board of Directors to issue preferred stock without shareholder approval, such as our Series A Preferred Stock issued in the HEYCO Merger;
- a classified Board of Directors so that not all members of our Board of Directors are elected at one time;
- the prohibition of cumulative voting in the election of directors; and
- a limitation on the ability of shareholders to call special meetings to those owning at least 25% of our outstanding shares of common stock.

Provisions of Texas law may also discourage, delay or prevent someone from acquiring or merging with us, which may cause the market price of our common stock to decline. Under Texas law, a shareholder who beneficially owns more than 20% of our voting stock, or an affiliated shareholder, cannot acquire us for a period of three years from the date this person became an affiliated shareholder, unless various conditions are met, such as approval of the transaction by our Board of Directors before this person became an affiliated shareholder or approval of the holders of at least two-thirds of our outstanding voting shares not beneficially owned by the affiliated shareholder.

Our Directors and Executive Officers Own a Significant Percentage of Our Equity, Which Could Give Them Influence in Corporate Transactions and Other Matters, and the Interests of Our Directors and Executive Officers Could Differ from Other Shareholders.

As of February 27, 2015, our directors and executive officers beneficially owned approximately 9% of our outstanding common stock and Series A Preferred Stock on an as-converted basis. Following the addition of George M. Yates to our board of directors, which we expect to occur no later than April 15, 2015, our directors and executive officers are expected to beneficially own approximately 15% of our outstanding common stock and Series A Preferred Stock on an as-converted basis. These shareholders could influence or control to some degree the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of any amendment to our certificate of formation or bylaws and the approval of mergers and other significant corporate transactions. Their influence or control of the Company may have the effect of delaying or preventing a change of control of the Company and may adversely affect the voting and other rights of other shareholders. In addition, due to their ownership interest in our common stock, our directors and executive officers may be able to remain entrenched in their positions.

Our Board of Directors Can Authorize the Issuance of Preferred Stock, Which Could Diminish the Rights of Holders of Our Common Stock and Make a Change of Control of the Company More Difficult Even if It Might Benefit Our Shareholders.

Our Board of Directors is authorized to issue shares of preferred stock in one or more series and to fix the voting powers, preferences and other rights and limitations of the preferred stock. Accordingly, we may issue shares of preferred stock with a preference over our common stock with respect to dividends or distributions on liquidation or dissolution, or that may otherwise adversely affect the voting or other rights of the holders of common stock. For example, in connection with the HEYCO Merger, we issued 150,000 shares of our Series A Preferred Stock, which will convert into shares of our common

Table of Contents

stock on a basis of 10 shares of common stock for each share of Series A Preferred Stock upon our shareholders' approval of the Charter Amendment. The holders of Series A Preferred Stock will vote, on an as-converted basis, together with the holders of common stock as a single class, except with respect to matters that would adversely affect the holders of Series A Preferred Stock as compared to the holders of common stock, in which case the holders of Series A Preferred Stock will vote as a separate class.

Issuances of preferred stock, such as the issuance of our Series A Preferred Stock, depending upon the rights, preferences and designations of the preferred stock, may have the effect of delaying, deterring or preventing a change of control of the company, even if that change of control might benefit our shareholders.

We May be Required to Pay Dividends on Shares of Our Series A Preferred Stock.

If our outstanding shares of Series A Preferred Stock are outstanding as of August 27, 2015, the holders of Series A Preferred Stock will be entitled to receive dividends on the Series A Preferred Stock in cash at a quarterly rate of $1.80 per share. The payment of such dividends may require a significant portion of our cash flows, which could materially adversely affect our financial condition and results of operations.

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 2. Properties.

See "Business" for descriptions of our properties. We also have various operating leases for rental of office space and office and field equipment. See "Note 13 – Commitments and Contingencies" to the consolidated financial statements in this Annual Report on Form 10-K for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings.

See "Note 13 – Commitments and Contingencies" to the consolidated financial statements in this Annual Report on Form 10-K. Such information is incorporated herein by reference.

Item 4. Mine Safety Disclosures.

Not applicable.

Table of Contents

PART II

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

General Market Information

Shares of our common stock are traded on the NYSE under the symbol "MTDR." Our shares have been traded on the NYSE since February 2, 2012. Prior to trading on the NYSE, there was no established public trading market for our common stock.

On February 27, 2015, following the closing of the HEYCO Merger, we had 76,728,605 shares of common stock outstanding held by approximately 350 record holders, excluding shareholders for whom shares are held in "nominee" or "street" name.

The following table sets forth the high and low sales prices of our common stock as reported by the NYSE for the periods indicated:

	2014		2013	
	High	Low	High	Low
First Quarter	$25.84	$17.95	$9.00	$7.58
Second Quarter	$29.36	$23.28	$12.48	$8.25
Third Quarter	$29.94	$23.70	$17.89	$11.49
Fourth Quarter	$26.09	$14.08	$24.10	$15.62

On February 27, 2015, the last reported sales price of our common stock on the NYSE was $21.66 per share.

Dividend Policy

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings to finance the expansion of our business. Our future dividend policy is within the discretion of our Board of Directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. In addition, certain covenants in our Credit Agreement may limit our ability to pay dividends on our common stock. During the years ended December 31, 2014 and 2013, we did not pay dividends to holders of our common stock.

As part of the consideration for the HEYCO Merger, we issued 150,000 shares of Series A Preferred Stock. Each share of Series A Preferred Stock will automatically convert into ten shares of our common stock, subject to customary anti-dilution adjustments, upon the vote and approval by our shareholders of the Charter Amendment. On February 25, 2015, we filed a definitive proxy statement with the Securities and Exchange Commission and began mailing to our shareholders such proxy materials related to a special meeting of shareholders to be held on April 2, 2015 at 9:30 a.m., Central Time, for the purpose of approving the Charter Amendment. All shareholders of record as of the close of business on February 18, 2015 will be entitled to vote at the special meeting.

If shares of our Series A Preferred Stock are outstanding as of August 27, 2015, the holders of such shares will be entitled to receive dividends on the Series A Preferred Stock in cash at a quarterly rate of $1.80 per share of Series A Preferred Stock. The payment of such dividends may require a significant portion of our cash flows, which could materially adversely affect our financial condition and results of operations.

Equity Compensation Plan Information

The following table presents the securities authorized for issuance under our equity compensation plans as of December 31, 2014.

Table of Contents

Equity Compensation Plan Information

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Shares Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders[(1)] [(2)]	1,968,182	$ 12.47	1,347,463
Equity compensation plans not approved by security holders	—	—	—
Total	1,968,182	$ 12.47	1,347,463

(1) Our Board of Directors has determined not to make any additional grants of awards under the Matador Resources Company 2003 Stock and Incentive Plan.

(2) Our 2012 Long-Term Incentive Plan was approved by our Board of Directors in December 2011 and took effect on January 1, 2012. The 2012 Long-Term Incentive Plan was also approved by our shareholders at the Annual Meeting of Shareholders on June 7, 2012. For a description of our 2012 Long-Term Incentive Plan, see “Note 8 – Stock-Based Compensation” to the consolidated financial statements in this Annual Report on Form 10-K.

Share Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock from February 2, 2012, the date our common stock began trading on the NYSE, through December 31, 2014, to that of the cumulative return on a $100 investment in the Russell 2000 Index and the Russell 2000 Energy Index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed.

This graph is not “soliciting material,” is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act , whether made before or after the date hereof and irrespective of any general incorporation language in any such filing. This graph is included in accordance with the SEC’s disclosure rules. This historic stock performance is not indicative of future stock performance.

Table of Contents

Comparison of Cumulative Total Return Among
Matador Resources Company, the Russell 2000 Index
and the Russell 2000 Energy Index

Table of Contents

Repurchase of Equity by the Company or Affiliates

During the quarter ended December 31, 2014, the Company re-acquired shares of common stock from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted stock.

Period	Total Number of Shares Purchased [1]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased under the Plans or Programs
October 1, 2014 to October 31, 2014	—	$—	—	—
November 1, 2014 to November 30, 2014	787	23.35	—	—
December 1, 2014 to December 31, 2014	779	20.23	—	—
Total	1,566	$21.80	—	—

(1) The shares were not re-acquired pursuant to any repurchase plan or program.

Table of Contents

Item 6. Selected Financial Data.

You should read the following selected financial data in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our historical consolidated financial statements and related notes thereto included elsewhere in this Annual Report on Form 10-K. The financial information included in this Annual Report on Form 10-K may not be indicative of our future results of operations, financial condition or cash flows.

The following selected financial information is summarized from our results of operations for the five-year period ended December 31, 2014 and selected consolidated balance sheet data at December 31, 2014, 2013, 2012, 2011 and 2010 and should be read in conjunction with the consolidated financial statements for the years ended December 31, 2014, 2013 and 2012 included herewith.

	Year Ended December 31,				
	2014	2013	2012	2011	2010
(In thousands, except per share data)					
Statement of operations data:					
Revenues					
Oil and natural gas revenues	$367,712	$269,030	$155,998	$67,000	$34,042
Realized gain (loss) on derivatives	5,022	(909)	13,960	7,106	5,299
Unrealized gain (loss) on derivatives	58,302	(7,232)	(4,802)	5,138	3,139
Total revenues	431,036	260,889	165,156	79,244	42,480
Expenses					
Production taxes and marketing	33,172	20,973	11,672	6,278	1,982
Lease operating	51,353	38,720	28,184	7,244	5,284
Depletion, depreciation and amortization	134,737	98,395	80,454	31,754	15,596
Accretion of asset retirement obligations	504	348	256	209	155
Full-cost ceiling impairment	—	21,229	63,475	35,673	—
General and administrative	32,152	20,779	14,543	13,394	9,702
Total expenses	251,918	200,444	198,584	94,552	32,719
Operating income (loss)	179,118	60,445	(33,428)	(15,308)	9,761
Other income (expense):					
Net loss on asset sales and inventory impairment	—	(192)	(485)	(154)	(224)
Interest expense	(5,334)	(5,687)	(1,002)	(683)	(3)
Interest and other income	1,345	225	224	315	364
Total other (expense) income	(3,989)	(5,654)	(1,263)	(522)	137
Net income (loss)	110,754	45,094	(33,261)	(10,309)	6,377
Net loss attributable to non-controlling interest in subsidiary	17	—	—	—	—
Net income (loss) attributable to Matador Resources Company shareholders	$110,771	$45,094	$(33,261)	$(10,309)	$6,377
Earnings (loss) per common share					
Basic					
Class A	$1.58	$0.77	$(0.62)	$(0.25)	$0.15
Class B	$—	$—	$(0.35)	$0.02	$0.42
Diluted					
Class A	$1.56	$0.77	$(0.62)	$(0.25)	$0.15
Class B	$—	$—	$(0.35)	$0.02	$0.42
Class B dividend declared, per share	$—	$—	$0.27	$0.27	$0.27

Table of Contents

	At December 31,				
	2014	2013	2012	2011	2010
(In thousands)					
Balance sheet data:					
Cash and cash equivalents	$8,407	$6,287	$2,095	$10,284	$21,060
Restricted cash	609	—	—	—	—
Certificates of deposit	—	—	230	1,335	2,349
Net property and equipment	1,322,072	845,877	591,090	399,865	303,880
Total assets	1,436,291	890,330	632,029	439,469	346,382
Current liabilities	161,787	100,327	96,492	74,576	30,097
Long-term liabilities	407,963	221,079	156,433	93,378	34,408
Total Matador Resources Company shareholders' equity	$866,408	$568,924	$379,104	$271,515	$281,877

	Year Ended December 31,				
	2014	2013	2012	2011	2010
(In thousands)					
Other financial data:					
Net cash provided by operating activities	$251,481	$179,470	$124,228	$61,868	$27,273
Net cash used in investing activities	(570,531)	(366,939)	(306,916)	(160,088)	(147,334)
Oil and natural gas properties capital expenditures	(560,849)	(363,192)	(300,689)	(156,431)	(159,050)
Expenditures for other property and equipment	(9,152)	(3,977)	(7,332)	(4,671)	(1,610)
Net cash provided by financing activities	321,170	191,661	174,499	87,444	36,891
Adjusted EBITDA [1]	$262,943	$191,771	$115,923	$49,911	$23,635

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see " – Non-GAAP Financial Measures" below.

Non-GAAP Financial Measures

We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA, because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

Table of Contents

	Year Ended December 31,				
	2014	2013	2012	2011	2010
(In thousands)					
Unaudited Adjusted EBITDA Reconciliation to Net Income (Loss):					
Net income (loss) attributable to Matador Resources Company shareholders	$110,771	$45,094	$(33,261)	$(10,309)	$6,377
Interest expense	5,334	5,687	1,002	683	3
Total income tax provision (benefit)	64,375	9,697	(1,430)	(5,521)	3,521
Depletion, depreciation and amortization	134,737	98,395	80,454	31,754	15,596
Accretion of asset retirement obligations	504	348	256	209	155
Full-cost ceiling impairment	—	21,229	63,475	35,673	—
Unrealized (gain) loss on derivatives	(58,302)	7,232	4,802	(5,138)	(3,139)
Stock-based compensation expense	5,524	3,897	140	2,406	898
Net loss on asset sales and inventory impairment	—	192	485	154	224
Adjusted EBITDA	$262,943	$191,771	$115,923	$49,911	$23,635

	Year Ended December 31,				
	2014	2013	2012	2011	2010
(In thousands)					
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:					
Net cash provided by operating activities	$251,481	$179,470	$124,228	$61,868	$27,273
Net change in operating assets and liabilities	5,978	6,210	(9,307)	(12,594)	(2,230)
Interest expense	5,334	5,687	1,002	683	3
Current income tax provision (benefit)	133	404	—	(46)	(1,411)
Net loss attributable to non-controlling interest in subsidiary	17	—	—	—	—
Adjusted EBITDA	$262,943	$191,771	$115,923	$49,911	$23,635

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains “forward-looking statements” that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in oil or natural gas prices, the timing of planned capital expenditures, availability under our Credit Agreement borrowing base, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of gathering, processing and transportation facilities, availability and integration of acquisitions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See “Cautionary Note Regarding Forward-Looking Statements.”

Overview

We are an independent energy company founded in July 2003 and engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Eagle Ford shale play in South Texas and the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas. We also operate in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

On February 2, 2012, our common stock began trading on the NYSE under the symbol “MTDR.” On February 7, 2012, we completed our initial public offering of 14,883,334 shares of common stock at $12.00 per share (the “Initial Public Offering”). We sold 12,209,167 shares of common stock in this offering and certain selling shareholders sold 2,674,167 shares of common stock, including shares sold pursuant to the partial exercise of the underwriters’ over-allotment option on March 7, 2012. Prior to trading on the NYSE, there was no established public trading market for our common stock.

Table of Contents

On September 10, 2013, we completed an underwritten public offering of 9,775,000 shares of our common stock, including 1,275,000 shares issued pursuant to the underwriters' exercise of their option to purchase additional shares. After deducting underwriting discounts, commissions and direct offering costs totaling approximately $7.4 million, we received net proceeds of approximately $141.7 million. We used the net proceeds from this offering primarily to fund a portion of our capital expenditures, including for the addition of a third rig to our drilling program. We also used the net proceeds from this offering to fund the acquisition of additional acreage in the Eagle Ford shale, the Permian Basin and the Haynesville shale and for other general working capital needs. Pending such uses, we used a portion of the net proceeds to repay $130.0 million in outstanding borrowings under our Credit Agreement in September 2013, which amounts were subsequently reborrowed in accordance with the terms of that facility for, among other items, the uses contemplated above.

On May 29, 2014, we completed a public offering of 7,500,000 shares of our common stock. After deducting direct offering costs totaling approximately $0.6 million, we received net proceeds of approximately $181.3 million. We used a portion of the net proceeds to repay $180.0 million in outstanding borrowings under our Credit Agreement, which amounts were subsequently reborrowed in accordance with the terms of that facility. The remaining $1.3 million of the offering net proceeds was used to fund working capital requirements.

Our business success and financial results are dependent on many factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Commodity price volatility, in particular, is a significant risk to our business and results of operations. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, the actions of OPEC, weather, pipeline capacity constraints, inventory storage levels, oil and natural gas price differentials and other factors. Prices for oil, natural gas and natural gas liquids will affect the cash flows available to us for capital expenditures and our ability to borrow and raise additional capital. Declines in oil, natural gas or natural gas liquids prices would not only reduce our revenues, but could also reduce the amount of oil, natural gas and/or natural gas liquids that we can produce economically, and as a result, could have an adverse effect on our financial condition, results of operations, cash flows and reserves. During 2014, we experienced sharp declines in oil and natural gas prices. For the year ended December 31, 2014, West Texas Intermediate oil prices declined from a high of approximately $107.26 per Bbl in mid-June to a low of $53.27 per Bbl in late December. Natural gas prices declined from a high of approximately $6.15 per MMBtu in mid-February to a low of approximately $2.89 per MMBtu in late December. As a result of this decline in commodity prices, we expect to reduce our drilling activities and capital expenditures by about 43% to $350.0 million (excluding capital expenditures associated with the HEYCO Merger) in 2015, as compared to the year ended December 31, 2014.

During the year ended December 31, 2014, we completed and began producing oil and natural gas from 36 gross (34.5 net) operated and eight gross (2.2 net) non-operated Eagle Ford shale wells. We also completed and began producing oil and natural gas from ten gross (9.5 net) operated and one gross (0.1 net) non-operated wells in the Permian Basin. We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana and East Texas during 2014, although we did participate in the drilling and completion of 46 gross (4.2 net) non-operated Haynesville shale wells, the most impactful of which were 14 gross (3.3 net) Haynesville wells completed and placed on production by Chesapeake on our Elm Grove properties in southern Caddo Parish, Louisiana.

In 2014, approximately 56% of our total capital expenditures of $610.4 million were directed to our operations in South Texas, primarily in the Eagle Ford shale, as we continued to increase our oil production and oil reserves. We also continued the evaluation and delineation of our acreage position in the Permian Basin during 2014. We increased our leasehold position significantly in the Permian Basin in Southeast New Mexico and West Texas during 2014. At December 31, 2014, we held approximately 92,700 gross (66,100 net) acres in the Permian Basin, as compared to approximately 70,800 gross (44,800 net) acres at December 31, 2013, and with the closing of the HEYCO Merger on February 27, 2015, our Permian Basin acreage position increased to 154,200 gross (85,400 net) acres. Approximately 37% of our 2014 capital expenditures were directed to our exploration and delineation program testing portions of our leasehold position in the Permian Basin and to the acquisition of additional leasehold interests prospective for the

Wolfcamp, Bone Spring and other oil and liquids-rich plays in the Permian Basin. In the first half of 2014, Chesapeake began the process of drilling up to an anticipated 45 gross (8.7 net) Haynesville shale wells on our Elm Grove acreage in southern Caddo Parrish, Louisiana, which we expect to continue through early 2017. We retain the right to participate for up to a 25% working interest in all wells drilled on this property with our working interest proportionately reduced to our leasehold position in any individual drilling unit. After notifying us of its intent to conduct this drilling program, Chesapeake began actively drilling these properties during the second quarter of 2014, and had up to five rigs operating on these properties at any one time during 2014. Approximately 7% of our total capital expenditures of $610.4 million were associated with non-operated Haynesville shale wells in 2014, including those wells drilled by Chesapeake.

Our average daily oil equivalent production for the year ended December 31, 2014 was 16,082 BOE per day, including 9,095 Bbl of oil per day and 41.9 MMcf of natural gas per day, an increase of 37% as compared to 11,740 BOE per day, including 5,843 Bbl of oil per day and 35.4 MMcf of natural gas per day, for the year ended December 31, 2013. Our average daily oil production in 2014 of 9,095 Bbl of oil per day was an increase of 56%, as compared to an average daily oil production

Table of Contents

of 5,843 Bbl of oil per day in 2013. This increase in oil production is primarily attributable to our ongoing development operations in the Eagle Ford shale as well as better-than-expected initial production contributions from wells drilled in the Permian Basin during 2014. Our average daily natural gas production of 41.9 Bcf per day for the year ended December 31, 2014 was an increase of 18% from 35.4 Bcf per day for the year ended December 31, 2013. This increase in natural gas production is primarily attributable to initial production contributions from wells drilled in the Permian Basin and to the increased natural gas production resulting from new, non-operated Haynesville shale wells completed and placed on production by Chesapeake on our Elm Grove properties in Northwest Louisiana during the second half of 2014. Our oil production, natural gas production and average daily oil equivalent production during 2014 were the best in Matador's history. Oil production comprised 57% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the year ended December 31, 2014, as compared to 50% for the year ended December 31, 2013 and only 37% for the year ended December 31, 2012.

Our oil and natural gas revenues and Adjusted EBITDA for the year ended December 31, 2014 were also the highest achieved for any year in our history. For the year ended December 31, 2014, our oil and natural gas revenues were $367.7 million, an increase of 37% from oil and natural gas revenues of $269.0 million for the year ended December 31, 2013. Our oil revenues and natural gas revenues increased 36% and 38% to approximately $290.0 million and $77.7 million, respectively, for the year ended December 31, 2014, as compared to $212.8 million and $56.2 million, respectively, for the year ended December 31, 2013. Adjusted EBITDA for the year ended December 31, 2014 was $262.9 million, an increase of 37% from an Adjusted EBITDA of $191.8 million reported for the year ended December 31, 2013. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "Selected Financial Data — Non-GAAP Financial Measures."

At December 31, 2014, our estimated total proved oil and natural gas reserves were 68.7 million BOE, including 24.2 million Bbl of oil and 267.1 Bcf of natural gas, with a PV-10 of $1.04 billion and a Standardized Measure of $913.3 million. At December 31, 2013, our estimated proved oil and natural gas reserves were 51.7 million BOE, including 16.4 million Bbl of oil and 212.2 Bcf of natural gas, with a PV-10 of $655.2 million and a Standardized Measure of $578.7 million. Our estimated proved oil reserves of 24.2 million Bbl at December 31, 2014 increased 48%, as compared to 16.4 million Bbl at December 31, 2013. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "Business — Estimated Proved Reserves."

Our estimated capital expenditure budget for 2015 is $350 million (excluding capital expenditures associated with the HEYCO Merger), and 96% is expected to be directed towards oil and liquids-rich opportunities. We expect to reduce our operated drilling program from five rigs, three in the Permian Basin and two in the Eagle Ford in January 2015, to two rigs early in the second quarter. We then plan to operate two rigs in the Permian Basin, one rig in Loving County, Texas and the other rig in Lea and Eddy Counties, New Mexico, for the remainder of 2015. As approximately 96% of our Eagle Ford acreage is either held by production or not burdened by leasehold expiration until 2016 or later, we plan to temporarily suspend our drilling activities in South Texas in 2015 until commodity prices improve sufficiently. Development of our Permian Basin assets will be the primary driver of our growth in 2015 and approximately $245 million, or 70%, of our 2015 estimated capital expenditures will be allocated to further delineation and development of our growing leasehold position in the Permian Basin. Our 2015 Permian Basin drilling program will focus on the development of the Wolf prospect area, the further delineation of the Ranger and Rustler Breaks prospect areas and the integration of the HEYCO acreage. We still plan to direct approximately $90 million, or 26%, of our estimated 2015 capital expenditures to drilling and completion operations in the Eagle Ford shale in South Texas. Although we do not plan to drill any operated Haynesville shale natural gas wells during 2015, approximately $15 million, or 4%, of our 2015 estimated capital expenditures will be allocated to participation in non-operated Haynesville shale wells in Northwest Louisiana. We believe that we should be able to fund our 2015 drilling program through a combination of operating cash flows, borrowings under our Credit Agreement (assuming availability under our borrowing base) or additional credit arrangements, potential joint ventures, the sale of assets or acreage and the potential issuance of equity and debt securities. While we have budgeted approximately $350.0 million of capital expenditures (excluding capital expenditures associated with the HEYCO Merger) for 2015, the aggregate amount of capital we expend may fluctuate materially based on market conditions, the actual costs to drill scheduled wells, wells drilled on properties we do not operate, our drilling results, other opportunities that may become available to us and our ability to obtain capital.

Table of Contents

Revenues

Our revenues are derived primarily from the sale of oil, natural gas and natural gas liquids production. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in oil, natural gas or natural gas liquids prices.

The following table summarizes our revenues and production data for the periods indicated:

	Year Ended December 31,		
	2014	2013	2012
Operating Data:			
Revenues (in thousands): [1]			
Oil	$290,026	$212,833	$123,654
Natural gas	77,686	56,197	32,344
Total oil and natural gas revenues	367,712	269,030	155,998
Realized gain (loss) on derivatives	5,022	(909)	13,960
Unrealized gain (loss) on derivatives	58,302	(7,232)	(4,802)
Total revenues	$431,036	$260,889	$165,156
Net Production Volumes: [1]			
Oil (MBbl)	3,320	2,133	1,214
Natural gas (Bcf)	15.3	12.9	12.5
Total oil equivalent (MBOE) [2]	5,870	4,285	3,294
Average daily production (BOE/d) [2]	16,082	11,740	9,000
Average Sales Prices:			
Oil, with realized derivatives (per Bbl)	$88.94	$98.67	$103.55
Oil, without realized derivatives (per Bbl)	$87.37	$99.79	$101.86
Natural gas, with realized derivatives (per Mcf)	$5.06	$4.47	$3.55
Natural gas, without realized derivatives (per Mcf)	$5.08	$4.35	$2.59

(1) We report our production volumes in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Revenues associated with natural gas liquids are included with our natural gas revenues.

(2) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

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

Oil and natural gas revenues. Our oil and natural gas revenues increased $98.7 million to $367.7 million, or an increase of 37% for the year ended December 31, 2014, as compared to $269.0 million for the year ended December 31, 2013. This increase in oil and natural gas revenues corresponds with an increase of 37% in our oil and natural gas production to 5.9 million BOE for the year ended December 31, 2014 from 4.3 million BOE for the year ended December 31, 2013. Our oil revenues increased $77.2 million, an increase of 36%, to $290.0 million for the year ended December 31, 2014, as compared to $212.8 million for the year ended December 31, 2013. Our oil production increased 56% to over 3.3 million Bbl of oil, or about 9,095 Bbl of oil per day, as compared to approximately 2.1 million Bbl of oil, or about 5,843 Bbl of oil per day, for the year ended December 31, 2013 due to our ongoing development operations in the Eagle Ford shale and from the better-than-expected performance of a number of our initial wells in the Permian Basin. Had the weighted average oil price we realized in 2014 remained consistent with the oil price we realized in 2013, the increase in oil production would have resulted in an increase in oil revenue of $118.5 million, for the year ended December 31, 2014. This potential increase of $41.2 million in oil revenues was not fully realized in 2014, however, as a result of a lower oil price of $87.37 per Bbl realized for the year ended December 31, 2014, as compared to $99.79 per Bbl realized for the year ended December 31, 2013. Our natural gas revenues increased $21.5 million, or an increase of 38%, to $77.7 million for the year ended December 31, 2014, as compared to $56.2 million for the year ended December 31, 2013. Our natural gas production increased 18% to approximately 15.3 Bcf for the year ended December 31, 2014, as compared to approximately 12.9 Bcf for the year ended December 31, 2013 due to our ongoing development activities in the Eagle Ford shale and the Permian Basin and to the natural gas production resulting from new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2014. This increase in natural gas production in 2014 resulted in increased natural gas revenues of $10.4 million, and the remaining increase in natural gas revenue of $11.1 million was due to a higher natural gas price of $5.08 per Mcf realized for the year ended December 31, 2014, as compared to $4.35 per Mcf realized for the year ended December 31, 2013.

Realized gain (loss) on derivatives. Our realized net gain on derivatives was approximately $5.0 million for the year ended December 31, 2014, as compared to a realized net loss of approximately $0.9 million for the year ended December 31,

2013. We realized a gain from our oil contracts of $5.2 million and a gain of $0.5 million from our natural gas liquids (“NGL”)contracts for the year ended December 31, 2014 due to oil prices being below the floor prices of some of our costless collar contracts and NGL prices being below the fixed prices of some of our swap contracts, respectively, especially during the latter part of 2014. These gains were partially offset by a loss of approximately $0.7 million on our natural gas contracts due to natural gas prices being in excess of the ceiling prices of our natural gas costless collar contracts, especially in the early months of 2014. Our realized net loss on derivatives was $0.9 million for the year ended December 31, 2013. We realized a loss from our oil contracts of approximately $2.4 million year ended December 31, 2013 due to oil prices in excess of the ceiling prices of some of our costless collar contracts and the fixed prices of our swap contracts. This loss was partially offset by gains of approximately $0.8 million and $0.7 million on our natural gas and NGL derivative contracts, respectively, due to the respective commodity prices being below the floor prices of our natural gas costless collar contracts and the fixed prices of our NGL swap contracts. We realized an average gain of approximately $2.00 per Bbl hedged on all of our oil costless collar contracts during the year ended December 31, 2014, as compared to an average loss of $1.42 per Bbl hedged for the year ended December 31, 2013. Our oil volumes hedged for the year ended December 31, 2014 were also 53% higher as compared to the year ended December 31, 2013. We realized an average loss of approximately $0.06 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2014, as compared to an average gain of approximately $0.10 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2013. Our total natural gas volumes hedged for the year ended December 31, 2014 were also 46% higher than the total natural gas volumes hedged for the year ended December 31, 2013.

Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $58.3 million for the year ended December 31, 2014, as compared to an unrealized loss of approximately $7.2 million for the year ended December 31, 2013. During the year ended December 31, 2014, the net fair value of our open oil, natural gas and natural gas liquids derivatives contracts increased to approximately $55.5 million, from $(2.8) million for the year ended December 31, 2013, resulting in an unrealized gain on derivatives of approximately $58.3 million for the year ended December 31, 2014. During the year ended year ended December 31, 2014, the net fair value of our open oil, natural gas and NGL derivative contracts increased by $47.2 million, $9.1 million and $2.0 million, respectively, due primarily to the decrease in the underlying commodities’ futures prices as compared to the year ended December 31, 2013.

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

Oil and natural gas revenues. Our oil and natural gas revenues increased by $113.0 million to $269.0 million, or an increase of about 72%, for the year ended December 31, 2013, as compared to $156.0 million for the year ended December 31, 2012. This increase in oil and natural gas revenues corresponds with an increase of 30% in our and natural gas production to 4.3 million BOE for the year ended December 31, 2013, from 3.3 million BOE for the year ended December 31, 2012. Our oil revenues increased $89.2 million, or an increase of 72%, to $212.8 million for the year ended December 31, 2013, as compared to $123.7 million for the year ended December 31, 2012. Our oil production increased 76% to over 2.1 million Bbl of oil, or about 5,843 Bbl of oil per day, as compared to approximately 1.2 million Bbl of oil, or about 3,317 Bbl of oil per day, for the year ended December 31, 2012 due to our drilling operations in the Eagle Ford shale. The increase in our oil revenues in 2013 was mostly attributable to the increase in oil production, but was partially offset by a slightly lower oil price of $99.79 per Bbl realized for the year ended December 31, 2013, as compared to $101.86 per Bbl realized for the year ended December 31, 2012. Our natural gas revenues increased $23.9 million, an increase of 74%, to $56.2 million for the year ended December 31, 2013, due to higher prices and increased production. The vast majority of the increase in natural gas revenues, or $22.7 million, resulted from a significantly higher weighted average natural gas price of $4.35 per Mcf realized during the year ended December 31, 2013, as compared to a weighted average natural gas price of $2.59 per Mcf realized during the year ended December 31, 2012. The 3% increase in our natural gas production to approximately 12.9 Bcf for the year ended December 31, 2013, as compared to approximately 12.5 Bcf for the year ended December 31, 2012 resulted in an increase in natural gas revenues of $1.1 million during 2013, as compared to 2012. This slight increase in natural gas production is due to an increase in natural gas production from our Eagle Ford shale wells during 2013, which was sufficient to offset the decline in natural gas production from our Haynesville and Cotton Valley wells in Northwest Louisiana and East Texas.

Realized gain (loss) on derivatives. Our realized net loss on derivatives was approximately $0.9 million for the year ended December 31, 2013, as compared to a realized net gain of $14.0 million for the year ended December 31, 2012. We realized a loss from our oil contracts of approximately $2.4 million for the year ended December 31, 2013 due to oil prices in excess of the ceiling prices of some our costless collar contracts and the fixed prices of our swap contracts. This loss was partially offset by gains of approximately $0.8 million and $0.7 million on our natural gas and NGL contracts, respectively, due to the respective commodity prices being below the floor prices of our natural gas costless collars and the fixed prices of our NGL swap contracts. During the year ended December 31, 2012, we realized a gain of approximately $2.0 million, $11.9 million and $21,000 on our oil, natural gas and NGL derivative contracts, respectively. These gains were the result of the respective commodity prices being below the floor and fixed prices of our oil costless collar and swap contracts, natural gas costless collar contracts and NGL swap contracts. We realized an average loss of approximately $1.42 per Bbl hedged on all of our oil costless collar and swap contracts during the year ended December 31, 2013, as compared to an average gain of $1.74 per Bbl hedged for the year ended December 31, 2012. Our oil volumes hedged for the year ended December 31, 2013 were also 44% higher as compared to the year ended December 31, 2012. We realized an average gain of approximately $0.10 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2013, as compared to an average gain of approximately $1.45 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2012. Our total natural gas volumes hedged for the year ended December 31, 2013 were also 5% higher than the total natural gas volumes hedged for the year ended December 31, 2012.

Unrealized gain (loss) on derivatives. Our unrealized loss on derivatives was approximately $7.2 million for the year ended December 31, 2013, as compared to an unrealized loss of approximately $4.8 million for the year ended December 31, 2012. During the year ended December 31, 2013, the net fair value of our open oil, natural gas and natural gas liquids derivative contracts decreased to approximately $(2.8) million, from approximately $4.5 million, for the year ended December 31, 2012, resulting in an unrealized loss on derivatives of approximately $7.2 million for the year ended December 31, 2013. During the year ended December 31, 2013, the net fair value of our open oil, natural gas and NGL derivative contracts decreased by $5.3 million, $1.6 million and $0.3 million, respectively, due primarily to the increase in the underlying commodities’ futures prices as compared to the year ended December 31, 2012.

Expenses

The following table summarizes our operating expenses and other income (expense) for the periods indicated.

	Year Ended December 31,		
	2014	2013	2012
(In thousands, except expenses per BOE)			
Expenses:			
Production taxes and marketing	$33,172	$20,973	$11,672
Lease operating	51,353	38,720	28,184
Depletion, depreciation and amortization	134,737	98,395	80,454
Accretion of asset retirement obligations	504	348	256
Full-cost ceiling impairment	—	21,229	63,475
General and administrative	32,152	20,779	14,543
Total expenses	251,918	200,444	198,584
Operating income (loss)	179,118	60,445	(33,428)
Other (expense) income:			
Net loss on asset sales and inventory impairment	—	(192)	(485)
Interest expense	(5,334)	(5,687)	(1,002)
Interest and other income	1,345	225	224
Total other expense	(3,989)	(5,654)	(1,263)
Income (loss) before income taxes	175,129	54,791	(34,691)
Total income tax provision (benefit)	64,375	9,697	(1,430)
Net loss attributable to non-controlling interest in subsidiary	17	—	—
Net income (loss) attributable to Matador Resources Company shareholders	$110,771	$45,094	$(33,261)
Expenses per BOE:			
Production taxes and marketing	$5.65	$4.89	$3.54
Lease operating	$8.75	$9.04	$8.56
Depletion, depreciation and amortization	$22.95	$22.96	$24.43
General and administrative	$5.48	$4.85	$4.42

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

Production taxes and marketing. Our production taxes and marketing expenses increased by $12.2 million to $33.2 million, an increase of 58%, for the year ended December 31, 2014, as compared to $21.0 million for the year ended

December 31, 2013. On a unit-of-production basis, however, our production taxes and marketing expenses increased by only 16% to $5.65 per BOE for the year ended December 31, 2014, as compared to $4.89 per BOE for the year ended December 31, 2013. Much of this increase was attributable to increased production taxes associated with the large increase in our oil production during 2014 resulting from our drilling operations in the Eagle Ford shale, as well as initial production from our newly drilled wells in the Permian Basin. Our total production was comprised of approximately 57% oil and 43% natural gas during the year ended December 31, 2014, as compared to approximately 50% oil and 50% natural gas during the year ended December 31, 2013. The increase in production taxes and marketing expenses during the year ended December 31, 2014 also reflected the increase in natural gas production from the Eagle Ford shale where natural gas production taxes are higher than production taxes

Table of Contents

associated with Haynesville shale natural gas in Louisiana, as well as increased marketing expenses on certain of our non-operated Eagle Ford and Haynesville properties in 2014.

Lease operating expenses. Our lease operating expenses increased by $12.6 million to $51.4 million, an increase of 33%, for the year ended December 31, 2014, as compared to $38.7 million for the year ended December 31, 2013. Our lease operating expenses per unit of production decreased 3% to $8.75 per BOE for the year ended December 31, 2014, as compared to $9.04 per BOE for the year ended December 31, 2013. Our total oil and natural gas production increased 37% to approximately 5.9 million BOE for the year ended December 31, 2014 from approximately 4.3 million BOE for the year ended December 31, 2013, including an increase of 56% in oil production to over 3.3 million Bbl for the year ended December 31, 2014, as compared to 2.1 million Bbl for the year ended December 31, 2013, which would typically result in higher lease operating expenses. Oil production was 57% of total production by volume for the year ended December 31, 2014, as compared to only 50% of total production by volume for the year ended December 31, 2013. The decrease achieved in lease operating expenses on a unit-of-production basis was primarily attributable to the progress we have made in reducing our lease operating expenses in the Eagle Ford shale during the last twelve months, which was primarily attributable to (i) the installation of permanent production facilities on almost all of our Eagle Ford properties, alleviating the need for the extended use of flowback equipment to produce newly completed Eagle Ford wells, (ii) the early use of gas lift on most of our newly completed Eagle Ford wells, (iii) a decrease in salt water disposal costs on a per barrel basis, and (iv) continued improvement in overall operational processes in our South Texas operations.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $36.3 million to $134.7 million, an increase of 37%, for the year ended December 31, 2014, as compared to $98.4 million for the year ended December 31, 2013. On a unit-of-production basis, however, our depletion, depreciation and amortization expenses remained essentially flat at $22.95 per BOE for the year ended December 31, 2014, as compared to $22.96 per BOE for the year ended December 31, 2013. The absolute increase in our depletion, depreciation and amortization expenses reflects an increase of approximately 37% in our total oil and natural gas production to 5.9 million BOE for the year ended December 31, 2014 from 4.3 million BOE for the year ended December 31, 2013. This increase on an absolute basis was offset on a unit-of-production basis by the increase in our proved oil and natural gas reserves of 33% to 68.7 million BOE at December 31, 2014 from 51.7 million BOE at December 31, 2013. This increase in total proved oil and natural gas reserves was primarily attributable to the continued development of our acreage in the Eagle Ford shale and the initial delineation and development of our acreage in the Permian Basin. As a result of this increase in proved oil and natural gas reserves, depletion, depreciation and amortization expenses on a unit-of production basis remained essentially flat year-over-year.

Full-cost ceiling impairment. No impairment to the net carrying value of our oil and natural gas properties and no corresponding charge resulting from a full-cost ceiling impairment was recorded during the year ended December 31, 2014. No impairment to the net carrying value of our oil and natural gas properties and no corresponding charge resulting from a full-cost ceiling impairment was recorded during the quarters ended December 31, 2013, September 30, 2013 or June 30, 2013. During the quarter ended March 31, 2013, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $13.7 million. As a result, we recorded an impairment charge of $21.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $7.5 million. This full-cost ceiling impairment of $21.2 million is reflected in our operating expenses for the year ended December 31, 2013, and resulted primarily from the continued low weighted average index price for natural gas used to estimate proved natural gas reserves at March 31, 2013, which was $2.95 per MMBtu for the period of time from April 2012 through March 2013.

General and administrative. Our general and administrative expenses increased by $11.4 million to $32.2 million, an increase of 55%, for the year ended December 31, 2014, as compared to $20.8 million for the year ended December 31, 2013. The increase in our general and administrative expenses was primarily attributable to increased payroll expenses associated with additional personnel joining the Company during the year ended December 31, 2014 to support our increased land, geoscience, drilling, completion and production operations. The remaining increase is largely due to a $1.6 million increase in non-cash stock-based compensation expenses to $5.5 million for the year ended December 31, 2014, as compared to $3.9 million for the year ended December 31, 2013. The increase in our non-cash stock-based compensation expense was attributable to the increased expense related to the continued vesting of awards granted in 2012, 2013 and 2014 of $5.3 million for the year ended December 31, 2014, as compared to $2.9 million for the year ended December 31, 2013. This increase was offset by the decreased expense related to our liability-based stock options of $0.2 million for the year ended December 31, 2014, as compared to $1.0 million for the year ended December 31, 2013. This decreased expense related to our liability-based stock options was attributable to the smaller increase in our stock price from $18.64 per share at December 31, 2013 to $20.23 per share at December 31, 2014, as compared to the larger increase from $8.20 per share at December 31, 2012 to $18.64 at December 31, 2013. Our general and administrative expenses increased by only 13% on a unit-of-production basis to $5.48 per BOE for the year ended December 31, 2014, as compared to $4.85 for the year ended December 31, 2013.

Table of Contents

Interest expense. For the year ended December 31, 2014, we incurred total interest expense of approximately $8.2 million. We capitalized approximately $2.8 million of our interest expense on certain qualifying projects for the year ended December 31, 2014 and expensed the remaining $5.3 million to operations. For the year ended December 31, 2013, we incurred total interest expense of approximately $7.6 million. We capitalized approximately $1.9 million of our interest expense on certain qualifying projects for the year ended December 31, 2013 and expensed the remaining $5.7 million to operations. The increase in total interest expense for the year ended December 31, 2014 of $0.6 million, as compared to the year ended December 31, 2013, was primarily attributable to higher average outstanding borrowings under our Credit Agreement during 2014, as compared to average outstanding borrowings under our Credit Agreement during 2013. In May 2014, we used a portion of the net proceeds of our public equity offering to repay $180.0 million of outstanding borrowings under our Credit Agreement. At December 31, 2014, we had $340.0 million in borrowings and $0.6 million in letters of credit outstanding under our Credit Agreement, and the effective interest rate on our borrowings was approximately 3.3% per annum. In September 2013, we used a portion of the net proceeds of our public equity offering to repay $130.0 million of outstanding borrowings under our Credit Agreement. At December 31, 2013, we had $200.0 million in borrowings and $0.3 million in letters of credit outstanding under our Credit Agreement.

Total income tax provision (benefit). We recorded a total income tax provision of approximately $64.4 million for the year ended December 31, 2014, as compared to a total income tax provision of approximately $9.7 million for the year ended December 31, 2013. For the year ended December 31, 2014, we incurred an estimated alternative minimum tax ("AMT") liability of $0.1 million, which represents the current portion of the income tax provision. The remaining income tax provision of $64.2 million represents deferred taxes for the year ended December 31, 2014. Our effective tax rate for the year ended December 31, 2014 was 36.8%. Total income tax expense for the year ended December 31, 2014 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due to the impact of permanent differences between book and taxable income. For the year ended December 31, 2013, we incurred an estimated AMT liability of $0.4 million, which represents the current portion of the income tax provision. The remaining $9.3 million represents deferred taxes for the year ended December 31, 2013. Our effective tax rate for the year ended December 31, 2013 was 17.7%. Total income tax expense for the year ended December 31, 2013 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to (i) the reversal of the valuation allowance of approximately $8.9 million on our federal deferred tax assets at December 31, 2012, as our federal deferred tax liability exceeded our federal deferred tax assets for the year ended December 31, 2013, (ii) the reversal of a state valuation allowance of approximately $1.3 million, as we believe we will be able to utilize the state net operating losses prior to their expiration, and (iii) the impact of permanent differences between book and taxable income.

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

Production taxes and marketing. Our production taxes and marketing expenses increased by $9.3 million to $21.0 million, an increase of 80%, for the year ended December 31, 2013, as compared to $11.7 million for the year ended December 31, 2012. The majority of this increase was attributable to increased production taxes associated with the large increase in our oil production during 2013 resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 50% oil and 50% natural gas during the year ended December 31, 2013, as compared to approximately 37% oil and 63% natural gas during the year ended December 31, 2012. On a unit-of-production basis, our our production taxes and marketing expenses increased by 38% to $4.89 per BOE for the year ended December 31, 2013, as compared to $3.54 per BOE for the year ended December 31, 2012. Production taxes on a unit-of-production basis on our oil and natural gas production in Texas are effectively higher than the production taxes on a unit-of-production basis on our production in Louisiana. As a result, the shift in our focus from the Haynesville shale in Northwest Louisiana to the Eagle Ford shale in South Texas has also resulted in an increase in our production taxes.

Lease operating expenses. Our lease operating expenses increased by $10.5 million to $38.7 million, an increase of 37%, for the year ended December 31, 2013, as compared to $28.2 million for the year ended December 31, 2012. Our total oil and natural gas production increased by 30% to approximately 4.3 million BOE for the year ended December

31, 2013 from approximately 3.3 million BOE for the year ended December 31, 2012, and our oil production increased 76% to over 2.1 million Bbl for the year ended December 31, 2013, as compared to 1.2 million Bbl for the year ended December 31, 2012. Our lease operating expenses per unit-of-production increased 6% to $9.04 per BOE for the year ended December 31, 2013, as compared to $8.56 per BOE for the year ended December 31, 2012. This increase in lease operating expenses was primarily attributable to the overall increase in oil and the higher lifting costs associated with oil production between the two years, as well as to the increased percentage of oil being produced, which was approximately 50% of total production by volume for the year ended December 31, 2013, as compared to 37% of total production by volume for the year ended December 31, 2012.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $17.9 million to $98.4 million, or an increase of about 22%, for the year ended December 31, 2013, as compared to $80.5 million for the year ended December 31, 2012. On a unit-of-production basis, our depletion, depreciation and amortization expenses were

$22.96 per BOE for the year ended December 31, 2013, a decrease of 6%, from $24.43 per BOE for the year ended December 31, 2012. The decrease in our depletion, depreciation and amortization expenses reflects an increase of approximately 30% in our total oil and natural gas production to 4.3 million BOE for the year ended December 31, 2013 from 3.3 million BOE for the year ended December 31, 2012. Because we use the unit-of-production method for calculating depletion, depreciation and amortization expense, the impact of the increased production experienced in the year ended December 31, 2013, as compared to the year ended December 31, 2012, on our depletion, depreciation and amortization expenses was offset by the increase in our proved oil and natural gas reserves to 51.7 million BOE at December 31, 2013 from 23.8 million BOE at December 31, 2012. Primarily as a result of continued improvement in natural gas prices over the past year, we added approximately 134.2 Bcf (22.4 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our estimated total proved reserves in the second, third and fourth quarters of 2013, which are reflected in our estimated total proved reserves at December 31, 2013. We had removed a large portion of these proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012 because the unweighted arithmetic average natural gas price had declined to $3.146 per MMBtu, a price at which the natural gas volumes associated with almost all of our identified Haynesville shale well locations could no longer be classified as proved undeveloped reserves.

Full-cost ceiling impairment. No impairment to the net carrying value of our oil and natural gas properties and no corresponding charge resulting from a full-cost ceiling impairment was recorded during the quarters ended December 31, 2013, September 30, 2013 or June 30, 2013. During the quarter ended March 31, 2013, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $13.7 million. As a result, we recorded an impairment charge of $21.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $7.5 million. This full-cost ceiling impairment of $21.2 million is reflected in our operating expenses for the year ended December 31, 2013, and resulted primarily from the continued low weighted average index price for natural gas used to estimate proved natural gas reserves at March 31, 2013, which was $2.95 per MMBtu for the period of time from April 2012 through March 2013. At June 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $21.3 million. As a result, we recorded an impairment charge of $33.2 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $11.9 million. At September 30, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $2.3 million. As a result, we recorded an impairment charge of $3.6 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $1.3 million. At December 31, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $17.3 million. As a result, we recorded an impairment charge of $26.7 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $9.4 million. These full-cost ceiling impairment charges in 2012 were primarily attributable to declining natural gas prices throughout much of the year. As a result of substantially lower natural gas prices in 2012, we had downward revisions of our natural gas reserves totaling 103.4 Bcf (17.2 million BOE), including the removal of 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves at June 30, 2012. These impairment charges are reflected in our operating expenses for the year ended December 31, 2012.

General and administrative. Our general and administrative expenses increased by $6.2 million to $20.8 million, or an increase of 43%, for the year ended December 31, 2013, as compared to $14.5 million for the year ended December 31, 2012. The increase in our general and administrative expenses was primarily attributable to a $3.8 million increase in stock-based compensation costs to $3.9 million for the year ended December 31, 2013, as compared to $0.1 million for the year ended December 31, 2012. The increase in our stock-based compensation expense was primarily attributable to the continued vesting of awards granted in 2012 and 2013, as well as the increased fair value of our liability-based stock options during the year ended December 31, 2013 due to the increase in our stock price from $8.20 per share at December 31, 2012 to $18.64 per share at December 31, 2013. The remaining increase in our general and administrative expenses was primarily due to additional payroll expenses associated with personnel added between the respective periods to support our increased operations, some of which was offset by $1.0 million of our general and administrative expenses for the year ended December 31, 2013 that was capitalized in connection with the permanent production facilities being constructed on certain of our properties in the Eagle Ford shale in South Texas during the second quarter of 2013. Our general and administrative expenses increased by only 10% on a unit-of-production basis to $4.85 per BOE for the year ended December 31, 2013, as compared to $4.42 per BOE for the year ended December 31, 2012. On a unit-of-production basis, the increase in general and administrative expenses was partially offset by the increase of approximately 30% in our total oil and natural gas production to 4.3 million BOE from 3.3 million BOE during the respective periods.

Interest expense. For the year ended December 31, 2013, we incurred total interest expense of approximately $7.6 million. We capitalized approximately $1.9 million of our interest expense on certain qualifying projects for the year ended December 31, 2013 and expensed the remaining $5.7 million to operations. For the year ended December 31, 2012, we incurred total interest expense of approximately $2.6 million. We capitalized approximately $1.6 million of our interest expense

Table of Contents

on certain qualifying projects for the year ended December 31, 2012 and expensed the remaining $1.0 million to operations. The increase in interest expense for the year ended December 31, 2013 of $4.7 million, as compared to the year ended December 31, 2012, was primarily attributable to higher average outstanding borrowings under our Credit Agreement during 2013, as compared to average outstanding borrowings under our Credit Agreement during 2012. In September 2013, we used a portion of the net proceeds of our public equity offering to repay $130.0 million of outstanding borrowings under our Credit Agreement. At December 31, 2013, we had $200.0 million in borrowings and $0.3 million in letters of credit outstanding under our Credit Agreement, and the effective interest rate on our borrowings was approximately 3.3% per annum. In February 2012, we used a portion of the net proceeds of our Initial Public Offering to repay our then outstanding borrowings of $123.0 million. At December 31, 2012, we had $150.0 million in borrowings and $1.1 million in letters of credit outstanding under our Credit Agreement.

Total income tax provision (benefit). We recorded a total income tax benefit of approximately $9.7 million for the year ended December 31, 2013, as compared to a total income tax benefit of approximately $1.4 million for the year ended December 31, 2012. For the year ended December 31, 2013, we incurred an estimated AMT liability of $0.4 million, which represents the current portion of the income tax provision. The remaining tax provision of $9.3 million represents deferred taxes for the year ended December 31, 2013. Our effective tax rate for the year ended December 31, 2013 was 17.7%. Total income tax expense for the year ended December 31, 2013 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to (i) the reversal of the valuation allowance of approximately $8.9 million on our federal deferred tax assets at December 31, 2012, as our federal deferred tax liability exceeded our federal deferred tax assets for the year ended December 31, 2013, (ii) the reversal of a state valuation allowance of approximately $1.3 million, as we now believe we will be able to utilize the state net operating losses prior to their expiration, and (iii) the impact of permanent differences between book and taxable income. During the year ended December 31, 2012, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $40.9 million. We recorded an impairment charge of $63.5 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $22.6 million. The increase in our deferred tax assets as a result of the impairment charges recorded during the year ended December 31, 2012 caused our deferred tax assets to exceed our deferred tax liabilities, resulting in the establishment of a valuation allowance of $10.3 million due to uncertainties regarding the future realization of our deferred tax assets. As a result, we recorded an income tax benefit of $1.4 million for the year ended December 31, 2012. We had a net loss for the year ended December 31, 2012.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue to be during 2015 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties. We continually evaluate potential capital sources, including additional borrowings, equity and debt financings and joint ventures, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital and to generate operating cash flows.

At December 31, 2014, we had cash totaling approximately $8.4 million, the borrowing base under our Credit Agreement was $450.0 million, and we had $340.0 million of outstanding long-term borrowings and approximately $0.6 million in outstanding letters of credit. These borrowings bore interest at an effective interest rate of approximately 3.3% per annum. From January 1 through February 27, 2015, we borrowed an additional $55.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures, to acquire additional leasehold interests and to consummate the HEYCO Merger. At February 27, 2015, following the closing of the HEYCO Merger, we had $395.0 million of outstanding long-term borrowings and approximately $0.6 million in outstanding letters of credit under the Credit Agreement and an additional $12.0 million of borrowings that was assumed in connection with the HEYCO Merger.

On May 29, 2014, we completed a public offering of 7,500,000 shares of our common stock. After deducting direct offering costs totaling approximately $0.6 million, we received net proceeds of approximately $181.3 million. We used a portion of the net proceeds to repay $180.0 million in outstanding borrowings under the Credit Agreement, which amounts were subsequently reborrowed in accordance with the terms of that facility. The remaining $1.3 million of the offering net proceeds was used to fund working capital requirements.

Our 2015 capital expenditure budget is estimated to be $350.0 million (excluding capital expenditures associated with the HEYCO Merger) and includes approximately $267.0 million for drilling and completing oil and natural gas exploration and development wells, with the remainder allocated to lease acquisitions, seismic data, midstream initiatives, pipelines and other infrastructure. Due to the sharp decline in oil and natural gas prices since mid-2014, we have reduced our estimated capital expenditure budget by approximately 43% from the $610.4 million in capital expenditures we incurred in 2014. We were operating five drilling rigs, two rigs in the Eagle Ford and three rigs in the Permian Basin, at the beginning of 2015, but plan to reduce our operated drilling rigs to two, both operating in the Permian Basin, during the second quarter of 2015. We then plan

Table of Contents

to operate two drilling rigs in the Permian Basin for the remainder of 2015. We plan to temporarily suspend our drilling program in the Eagle Ford shale for the balance of 2015 or until commodity prices increase sufficiently. We expect to fund our 2015 capital expenditure budget through a combination of operating cash flows, borrowings under our Credit Agreement (assuming availability under our borrowing base) or additional credit arrangements, potential joint ventures, the sale of assets or acreage and potential issuances of equity or debt securities, which may not be available on terms reasonably acceptable to us or at all.

Exploration and development activities are subject to a number of risks and uncertainties, which could cause these activities to be less successful than we anticipate and could impact our ability to sufficiently increase our reserves, cash flows from operations and borrowing base under our Credit Agreement. A significant portion of our anticipated cash flows from operations in 2015 is expected to come from producing wells and development activities on currently proved properties in the Eagle Ford shale in South Texas, the Wolfcamp and Bone Spring plays in the Permian Basin and the Haynesville shale in Louisiana. Our existing wells may not produce at the levels we are forecasting and our exploration and development activities in these areas may not be as successful as we anticipate. Additionally, our anticipated cash flows from operations are based upon current expectations of oil and natural gas prices for 2015 and the hedges we currently have in place. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices and to partially offset reductions in our cash flows from operations resulting from declines in commodity prices. At February 27, 2015, we have approximately 40% of our anticipated oil production and approximately 70% of our anticipated natural gas production hedged for the remainder of 2015. We currently have no hedges in place for oil or natural gas beyond 2015.

Due to the sharp decline in commodity prices since mid-2014, we anticipate that our operating cash flows in 2015 will be less than in 2014. Further, if our exploration, development and production activities result in less cash flows than anticipated, we may seek additional sources of capital, including through additional borrowings under our Credit Agreement, additional debt arrangements, the sale of assets or acreage or entering into one or more joint ventures, none of which may be available. In addition to future borrowings under our Credit Agreement, we may also seek to raise additional funds by issuing debt securities or selling shares of our common stock or securities convertible or exercisable into our common stock (including debt securities or other preferential securities) in the public markets or otherwise. Any such sales of equity or convertible securities would dilute the ownership interest of our existing shareholders. There is no guarantee that we would be able to sell such debt or equity securities on terms acceptable to us. It is also possible that, to the extent we are not able to obtain additional sources of capital, we may modify our planned capital expenditure budget for 2015 accordingly to further reduce our capital spending and rate of growth or enter into one or more joint ventures or other alternative financings. Exploration and development activities are subject to a number of risks and uncertainties that could impact our ability to sufficiently increase our reserves, cash flows from operations and the borrowing base under our Credit Agreement. See “Risk Factors — Our Exploration, Development and Exploitation Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth,” “Risk Factors — Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of Operational and Financial Risk, with Many Uncertainties That Could Adversely Affect Our Business” and “Risk Factors — Our Identified Drilling Locations Are Scheduled over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling.”

Our cash flows for the years ended December 31, 2014, 2013 and 2012 are presented below:

	Year Ended December 31,		
	2014	2013	2012
(In thousands)			
Net cash provided by operating activities	$251,481	$179,470	$124,228
Net cash used in investing activities	(570,531)	(366,939)	(306,916)

Net cash provided by financing activities	321,170	191,661	174,499
Net change in cash	$2,120	$4,192	$(8,189)

Cash Flows Provided by Operating Activities

Net cash provided by operating activities increased by $72.0 million to $251.5 million for the year ended December 31, 2014, as compared to net cash provided by operating activities of $179.5 million for the year ended December 31, 2013. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased significantly to $257.5 million for the year ended December 31, 2014 from $185.7 million for the year ended December 31, 2013. This increase is primarily attributable to the increase of approximately 56% in our oil production to just over 3.3 million Bbl from approximately 2.1 million Bbl during the respective periods. Changes in our operating assets and liabilities between

December 31, 2013 and December 31, 2014 also resulted in a net increase of approximately $0.2 million in net cash provided by operating activities for the year ended December 31, 2014, as compared to the year ended December 31, 2013.

Net cash provided by operating activities increased by $55.2 million to $179.5 million for the year ended December 31, 2013, as compared to net cash provided by operating activities of $124.2 million for the year ended December 31, 2012. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased significantly to $185.7 million for the year ended December 31, 2013 from $114.9 million for the year ended December 31, 2012. This increase is primarily attributable to the increase of approximately 76% in our oil production to just over 2.1 million Bbl from approximately 1.2 million Bbl during the respective periods. Changes in our operating assets and liabilities between December 31, 2013 and December 31, 2012 also resulted in a net decrease of approximately $15.5 million in net cash provided by operating activities for the year ended December 31, 2013, as compared to the year ended December 31, 2012.

Our operating cash flows are sensitive to a number of variables, including changes in our production and the volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, the actions of OPEC, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices. In addition, we attempt to avoid long-term service agreements in order to minimize ongoing future commitments. For additional information on the impact of changing prices on our financial condition, see "Quantitative and Qualitative Disclosures About Market Risk" below. See also "Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations."

Cash Flows Used in Investing Activities

Net cash used in investing activities increased by $203.6 million to $570.5 million for the year ended December 31, 2014 from $366.9 million for the year ended December 31, 2013. This increase in net cash used in investing activities reflected an increase of $197.7 million in our oil and natural gas properties capital expenditures for the year ended December 31, 2014, as compared to the year ended December 31, 2013, and an increase of approximately $5.2 million in expenditures for other property and equipment, which includes new pipeline infrastructure associated primarily with our properties in the Eagle Ford shale, but also reflects initial costs associated with a natural gas processing plant and a saltwater disposal facility we are constructing in Loving County, Texas. Approximately 87% of our capital expenditures were allocated to drilling and completion operations, associated infrastructure and midstream activities and 13% to the acquisition of additional acreage for the year ended December 31, 2014, as compared to approximately 83% allocated to drilling and completion operations and associated infrastructure and 17% allocated to acquisition of additional acreage for the year ended December 31, 2013. Cash used for oil and natural gas properties capital expenditures for the year ended December 31, 2014 was primarily attributable to our operated and non-operated drilling and completion activities in the Eagle Ford shale play, as well as to our operated drilling activities in the Permian Basin and certain non-operated drilling activities in the Haynesville shale. We also used a portion of this cash to acquire approximately 29,300 gross (21,800 net) acres in the Permian Basin in 2014, along with 3,200 gross (3,000 net) acres in the Eagle Ford shale.

Net cash used in investing activities increased by $60.0 million to $366.9 million for the year ended December 31, 2013 from $306.9 million for the year ended December 31, 2012. This increase in net cash used in investing activities reflected an increase of $62.5 million in our oil and natural gas properties capital expenditures for the year ended December 31, 2013, as compared to the year ended December 31, 2012, and a decrease of approximately $3.4 million in expenditures for other property and equipment, which included new pipeline infrastructure associated with our properties in the Eagle Ford shale. Approximately 83% of our capital expenditures were allocated to drilling and completion operations and associated infrastructure and 17% to the acquisition of additional acreage for the year ended December 31, 2013, as compared to approximately 91% allocated to drilling and completion operations and associated infrastructure and 9% allocated to acquisition of additional acreage for the year ended December 31, 2012.

Cash used for oil and natural gas properties capital expenditures for the year ended December 31, 2013 was primarily attributable to our operated and non-operated drilling and completion activities in the Eagle Ford shale play, as well as to our initial operated drilling activities in the Permian Basin. We also used a portion of this cash to acquire approximately 55,400 gross (38,900 net) additional acres in the Permian Basin during 2013, along with approximately 1,720 gross (1,660 net) acres in the Eagle Ford shale and 1,190 gross (1,190) net acres in the Haynesville shale.

Table of Contents

Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $350.0 million in capital (excluding capital expenditures associated with the HEYCO Merger) for acquisition, exploration and development activities in 2015 as follows:

	Amount (in millions)
Exploration and development drilling and completion costs	$267.0
Midstream activities	38.0
Pipeline and infrastructure expenditures	25.0
Leasehold acquisition and 2-D and 3-D seismic data	20.0
Total	$350.0

For further information regarding our anticipated 2015 capital expenditure budget, see "Business — General."

Our 2015 capital expenditures may be adjusted as business conditions warrant, as evidenced by the substantial reduction in our 2015 capital expenditures budget, as compared to our 2014 capital spending, in response to the sharp decline in oil and natural gas prices since mid-2014. The amount, timing and allocation of our capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline further or costs increase significantly, we could defer a significant portion of our anticipated capital expenditures until later periods to conserve cash or to focus on those projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and development activities, contractual obligations, drilling plans for properties we do not operate and other factors both within and outside our control.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities was $321.2 million for the year ended December 31, 2014, as compared to net cash provided by financing activities of $191.7 million for the year ended December 31, 2013. The net cash provided by financing activities for the year ended December 31, 2014 was primarily attributable to the total proceeds of our May 2014 public equity offering of $181.9 million and borrowings under our Credit Agreement of $320.0 million, offset by the costs of the offering of $0.6 million paid during the period and by the repayment of $180.0 million in borrowings under our Credit Agreement during the period.

Net cash provided by financing activities was $191.7 million for the year ended December 31, 2013, as compared to net cash provided by financing activities of $174.5 million for the year ended December 31, 2012. The net cash provided by financing activities for the year ended December 31, 2013 was primarily attributable to the total proceeds from our September 2013 public equity offering of $149.1 million and borrowings of $180.0 million under our Credit Agreement during the period, offset by the costs of the offering of $7.4 million incurred during the period and by the repayment of $130.0 million in borrowings under our Credit Agreement during the period.

Net cash provided by financing activities was $174.5 million for the year ended December 31, 2012. The net cash provided by financing activities for the year ended December 31, 2012 was principally due to the total proceeds from the Initial Public Offering of $146.5 million and total borrowings of $160.0 million under our Credit Agreement to fund a portion of our working capital requirements during the period, offset by the costs of the Initial Public Offering of $11.6 million incurred during the period and by the repayment of $123.0 million in borrowings during the period. We also received approximately $2.7 million from the exercise of stock options during the year ended December 31, 2012.

Credit Agreement

On September 28, 2012, we entered into the Credit Agreement, which increased the maximum facility amount from $400.0 million to $500.0 million. The Credit Agreement matures December 29, 2016. Our subsidiary, MRC Energy Company, is the borrower under the Credit Agreement. Borrowings are secured by mortgages on substantially all of our oil and natural gas properties, other than those properties acquired in the HEYCO Merger (which properties secure the approximately $12.0 million in indebtedness we assumed in the HEYCO Merger) and by the equity interests of all of MRC Energy Company's wholly-owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador, the parent corporation. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by the eligible subsidiaries of MRC Energy Company.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both we and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the first quarter of 2014, our lenders completed their review of our estimated total proved oil and natural gas reserves at December 31, 2013, and on March 12, 2014, the borrowing base under our Credit Agreement was increased to $385.0 million, and the conforming borrowing base was increased to $310.0 million. At that time, Wells Fargo, N.A. replaced Capital One, N.A. in our lending group, and we amended the Credit Agreement to, among other things, provide that the borrowing base will automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2015 or (ii) concurrent with the issuance by us of senior unsecured notes in an amount greater than or equal to $10.0 million. The Credit Agreement was also amended to eliminate the current ratio covenant and to increase the debt to EBITDA ratio covenant, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, to 4.25 or less. Furthermore, the interest rate charged to us based on our outstanding level of borrowings was reduced by 0.25% across the borrowing grid as a result of this amendment. This March 2014 redetermination constituted the regularly scheduled May 1 redetermination.

During the third quarter of 2014, the lenders completed their review of our estimated total proved oil and natural gas reserves at July 31, 2014, and on September 5, 2014, the borrowing base under our Credit Agreement was increased to $450.0 million, and the conforming borrowing base was increased to $375.0 million. This September 2014 redetermination constituted the regularly scheduled November 1 redetermination. We may request one additional unscheduled redetermination of our borrowing base prior to the next scheduled redetermination.

At February 27, 2015, the Lenders had begun the regularly scheduled May 1 redetermination of our borrowing base using our estimated total proved oil and natural gas reserves at December 31, 2014. Oil and natural gas prices have declined significantly in the six months since the last borrowing base redetermination in September 2014. As a result, the Company cannot be certain as to how much, if any, increase in its borrowing base may be achieved from this May 1 redetermination.

In the event of a borrowing base increase, we are required to pay a fee to the lenders equal to a percentage of the amount of the increase, which is determined based on market conditions at the time of the borrowing base increase. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

At December 31, 2014, we had $340.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. At December 31, 2014, our outstanding borrowings bore interest at an effective interest rate of approximately 3.3% per annum. From January 1, 2014 through February 27, 2015, we borrowed an additional $55.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures, to acquire additional leasehold interests and to consummate the HEYCO Merger. At February 27, 2015, following the closing of the HEYCO Merger, we had $395.0 million of outstanding long-term borrowings and approximately $0.6 million in outstanding letters of credit under the Credit Agreement and an additional approximately $12.0 million in indebtedness that we assumed in connection with the HEYCO Merger. We expect to access future borrowings under our Credit Agreement to fund a portion of our 2015 capital expenditure requirements in excess of amounts available from our operating cash flows.

If we borrow funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the prime rate for such day, (ii) the Federal Funds Effective Rate (as defined in the Credit Agreement) on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate (as defined in the Credit Agreement) plus 1.0% plus, in each case, an amount from 0.50% to 2.75% of such outstanding loan depending on the level of borrowings under the agreement. If we borrow funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Royal Bank of Canada (“RBC”) is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.50% to 3.75% of such outstanding loan depending on the level of borrowings under the Credit Agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by us. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. We include this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees, if any, as interest expense and in our interest rate calculations and related disclosures. The Credit Agreement requires us to maintain a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.25 or less.

Table of Contents

Subject to certain exceptions, our Credit Agreement contains various covenants that limit our ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of our assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of our assets.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the notes or any reimbursement obligation under any letter of credit when due or any fees or other amounts within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving us or our subsidiaries; and
- a change of control, as defined in the Credit Agreement.

During the second quarter of 2014, Bank of America, N.A. replaced Citibank, N.A. as a lender under the Credit Agreement.

At December 31, 2014, we believe that we were in compliance with the terms of our Credit Agreement.

Off-Balance Sheet Arrangements

From time-to-time, the Company enters into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2014, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) operating lease agreements, (ii) non-operated drilling commitments, (iii) termination obligations under drilling rig contracts, (iv) firm transportation and fractionation commitments, (v) agreements to construct facilities and (vi) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices or interest rates, gathering, treating, fractionation and transportation commitments on uncertain volumes of future throughput, open delivery commitments and indemnification obligations following certain divestitures. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. See “Obligations and Commitments” below and “Note 13 – Commitments and Contingencies” to the consolidated financial statements in this Annual Report on Form 10-K for more information regarding the Company's off-balance sheet arrangements. Such information is incorporated herein by reference.

Obligations and Commitments

We had the following material contractual obligations and commitments at December 31, 2014:

Table of Contents

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
(In thousands)					
Contractual Obligations:					
Revolving credit borrowings and term loan, including letters of credit [(1)]	$340,600	$—	$340,600	$—	$—
Office lease	7,047	971	1,790	1,868	2,418
Non-operated drilling commitments [(2)]	20,983	20,983	—	—	—
Drilling rig contracts [(3)]	50,351	28,388	21,963	—	—
Asset retirement obligations	11,951	311	900	2,897	7,843
Natural gas processing and transportation agreement [(4)]	5,988	2,992	2,996	—	—
Gas plant engineering, procurement, construction and installation contract [(5)]	14,900	14,900	—	—	—
Total contractual cash obligations	$451,820	$68,545	$368,249	$4,765	$10,261

(1) At December 31, 2014, we had $340.0 million in revolving borrowings outstanding under our Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. These borrowings mature in December 2016. These amounts do not include estimated interest on the obligations, because our revolving borrowings had short-term interest periods, and we are unable to determine what our borrowing costs may be in future periods.

(2) At December 31, 2014, we had outstanding commitments to participate in the drilling and completion of various non-operated wells. Our working interests in these wells are typically small, and certain of these wells were in progress at December 31, 2014. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $21.0 million at December 31, 2014, which we expect to incur within the next year.

(3) We do not own or operate our own drilling rigs, but instead we enter into contracts with third parties for such drilling rigs. These contracts establish daily rates for the drilling rigs and the term of our commitments for the drilling services to be provided, which have typically been for one year or less, although in 2014, we entered into longer-term contracts in order to secure new drilling rigs equipped with the latest technology in plays that were experiencing heavy demand for drilling rigs. Should we elect to terminate a contract and if the drilling contractor were unable to secure replacement work for the contracted drilling rigs or if the drilling contractor were unable to secure work for the contracted drilling rigs at the same daily rates being charged to us prior to the end of their respective contract terms, we would incur termination obligations. Our maximum outstanding aggregate termination obligations under our drilling rig contracts were approximately $50.4 million at December 31, 2014.

(4) Effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement for a significant portion of our operated natural gas production in South Texas. The undiscounted minimum commitments under this agreement total approximately $6.0 million at December 31, 2014.

(5) We entered into an agreement with a third party for the engineering, procurement, construction and installation of a natural gas processing plant in Loving County, Texas in 2014. This plant is expected to process a portion of our natural gas produced from certain of our wells in the Permian Basin, as well as third-party natural gas. The plant is scheduled to be completed and placed in service in the third quarter of 2015.

General Outlook and Trends

For the year ended December 31, 2014, oil prices ranged from a high of approximately $107.26 per Bbl in mid-June to a low of approximately $53.27 per Bbl in late December, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized a weighted average oil price of $87.37 per Bbl ($88.94 per Bbl including realized gains from oil derivatives) for our oil production for the year ended December 31, 2014, as compared to $99.79 per Bbl ($98.67 per Bbl including realized losses from oil derivatives) for the year ended December 31, 2013. At February 27, 2015, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date had declined further, closing at $49.76 per Bbl, as compared to $102.40 per Bbl at February 27, 2014.

For the year ended December 31, 2014, natural gas prices ranged from a high of approximately $6.15 per MMBtu in mid-February to a low of approximately $2.89 per MMBtu in late December, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a weighted average natural gas price of $5.08 per Mcf ($5.06 per Mcf including realized losses from natural gas and NGL derivatives) for our natural gas production for the year ended December 31, 2014, as compared to $4.35 per Mcf ($4.47 per Mcf including realized gains from natural gas and NGL derivatives) for the year ended December 31, 2013. At February 27, 2015, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date had declined further, closing at $2.73 per MMBtu, as compared to $4.51 per MMBtu at February 27, 2014.

In response to the sharp decrease in oil and natural gas prices experienced in late 2014 and early 2015, we have reduced our 2015 estimated capital expenditure budget to $350.0 million (excluding capital expenditures associated with the HEYCO Merger), as compared to actual capital expenditures of $610.4 million for the year ended December 31, 2014. This 2015 capital expenditure budget anticipates a reduction of our drilling program from five drilling rigs operating in January 2015 to two drilling rigs by the second quarter of 2015. We then plan to operate these two drilling rigs on our Permian Basin properties throughout the remainder of 2015. We also plan to temporarily suspend our development drilling program in the Eagle Ford shale after the first quarter of 2015, as approximately 96% of our Eagle Ford acreage was held by production or not burdened by lease expirations until 2016 at December 31, 2014. We would not expect to increase our operated drilling activities in either the Eagle Ford shale or the Permian Basin until oil prices improve sufficiently from their current levels. We also plan to direct a small portion of our 2015 capital expenditures, about 4%, to our participation in non-operated Haynesville shale wells in Northwest Louisiana.

Coincident with the recent decline in commodity prices, we have also begun to experience price reductions from our service providers for many of the products and services we use in our drilling and completion operations. At February 27, 2015, we were receiving price reductions of approximately 15% to 20% on many of the products and services we use, but we have also begun to see some price reductions as high as 50% on certain products and services. If oil and natural gas prices remain at their current levels for an extended period of time or should they decline further, we would anticipate receiving additional price reductions for drilling and completion products and services, although we can provide no assurances that these price reductions will occur or of their eventual magnitude.

Most of our Eagle Ford shale oil production in South Texas is sold based on a Louisiana Light Sweet oil price index less transportation costs. Although we realized significant uplifts to West Texas Intermediate oil prices at times during 2013, the differential between these two benchmark prices has decreased since early 2013. We may not realize similar, or any, uplifts to West Texas Intermediate oil prices in future periods, which could result in a decrease in our weighted average oil price realized and associated oil revenues. Additionally, oil production from our properties in the Permian Basin is sold on a West Texas Intermediate oil price index less transportation costs.

The prices we receive for oil, natural gas and natural gas liquids heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital and future rate of growth. Oil, natural gas and natural gas liquids are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil, natural gas and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. Declines in oil, natural gas or natural gas liquids prices not only reduce our revenue, but could also reduce the amount of oil, natural gas and natural gas liquids we can produce economically. From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. Even so, decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and natural gas liquids prices, and we may not always employ the optimal hedging strategy. This, in turn, may affect the liquidity that can be accessed through the borrowing base under our Credit Agreement and through the capital markets. See “Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations.”

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our oil and natural gas wells will experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil, natural gas and natural gas liquids price declines, however, drilling additional oil or natural gas wells may not be economical, and we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves, cash flows and our availability under our Credit Agreement. See “Risk Factors — Our Exploration, Development and Exploitation Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth.”

We strive to focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses during each reporting period. We believe that our estimates and assumptions are reasonable and reliable, and believe that the actual results will not differ significantly from those reported; however, such estimates and assumptions are subject to a number of risks and uncertainties, and such risks and uncertainties could cause the actual results to differ materially from our estimates. We consider the following to be our most critical accounting policies and estimates involving significant judgment or estimates by our management. See "Note 2 — Summary of Significant Accounting Policies" to the consolidated financial statements in this Annual Report on Form 10-K for further details on our accounting policies at December 31, 2014. Such information is incorporated herein by reference.

Property and Equipment

We use the full-cost method of accounting for our investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred. These costs are accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities.

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center "ceiling". The cost center ceiling is defined as the sum of:

(a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus

(b) unproved and unevaluated property costs not being amortized, plus

(c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less

(d) income tax effects related to the properties involved.

Any excess of our net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. The fair value of our derivative instruments is not included in the ceiling test computation as we do not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent upon the quantities of proved reserves, the estimation of which requires substantial judgment. The associated commodity prices and the applicable discount rate used in these estimates are in accordance with guidelines established by the SEC. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. Future net revenues are calculated using commodity prices that represent the arithmetic averages of the first-day-of-the-month price for the 12-month period prior to the end of each quarterly period, and the guidelines further dictate that a 10% discount factor be used to determine the present value of future net revenues.

Because the cost center ceiling calculation is based on the average of historical prices, which may or may not be representative of future prices, and requires a 10% discount factor, the resulting estimated value may not be indicative of the fair market value of our properties. Any impairment related to the excess of our net capitalized costs above the resulting cost center ceiling should not be viewed as an absolute indicator of a reduction in the ultimate value of the related reserves.

Because of the volatile nature of oil and gas prices, it generally is not possible to predict the timing or magnitude of full-cost impairments. In addition, due to the inter-relationship of the various judgments made to estimate proved reserves, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates. However, decreases in estimates of proved reserves would generally increase our depletion rate and, thus, our depletion expense. Decreases in our proved reserves may also increase the likelihood of recognizing a full-cost ceiling impairment.

Although uncertain future oil and natural gas prices impact the ability to predict future full-cost ceiling impairments, we do anticipate recognizing full-cost ceiling impairments in 2015, beginning as early as the first quarter of 2015. This conclusion is based on the historic commodity prices for the last nine months of 2014 and the first two months of 2015 as well as the short-term pricing outlook. Although we can predict with relative certainty that we will recognize full-cost ceiling impairments in 2015, we are not able to reasonably estimate the amounts of any such impairments.

However, we expect the amounts, if realized, will be material to our net income and earnings per share but will have no impact on our cash flows from operations, liquidity or capital resources.

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion.

Impairment

Unproved and unevaluated properties are assessed for impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Exploratory dry holes are included in the amortization base immediately upon the determination that the well is not productive.

Derivative Financial Instruments

From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. These instruments consist of put and call options in the form of costless (or zero-cost) collars and swap contracts. Costless collars provide us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially "costless" to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified period, providing downside price protection.

Prior to settlement, our derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. We have elected not to apply hedge accounting for our existing derivative financial instruments, and as a result, we recognize the change in derivative fair value between reporting periods currently in our consolidated statement of operations. Such changes in fair value are reported under "Revenue" as "Unrealized gain (loss) on derivatives". Changes in the fair value of these open derivative financial instruments can have a significant impact on our reported results from period to period but do not impact our cash flow from operations, liquidity or capital resources. The fair value of our derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Realized gains and realized losses from the settlement of derivative financial instruments do have a direct impact on our cash flow from operations and liquidity. The impact of these settlements is also reported under "Revenue" as "Realized gain (loss) on derivatives".

Revenue Recognition

We follow the sales method of accounting for our oil, natural gas and natural gas liquids revenue, whereby we recognize revenue, net of royalties, on all oil, natural gas and natural gas liquids sold to purchasers regardless of whether the sales are proportionate to our ownership in the property. Under this method, revenue is recognized at the time the oil, natural gas and natural gas liquids are produced and sold, and we accrue for revenue earned but not yet received.

Stock-Based Compensation

We account for stock-based compensation in accordance with ASC 718. During 2014, 2013 and 2012 all stock option awards were granted under our 2012 Long-Term Incentive Plan and were equity instruments. We did not grant any stock option awards in 2011. Prior to 2011, all stock option awards were granted under our 2003 Stock and Incentive Plan, and since November 22, 2010, these awards have been accounted for as liability instruments. We used the fair value method to measure and recognize the liability associated with our outstanding liability-based stock options and to measure and recognize the equity associated with our equity-based stock options. Stock options typically vest over three or four years, and the associated compensation expense is recognized on a straight-line basis over the vesting period. Restricted stock and restricted stock units typically vest over a period of one to four years, and compensation expense is recognized on a straight line basis over the vesting period. As our shares were not publicly traded prior to February 2, 2012, we estimated the future volatility of our stock using the historical volatility of the common stock of a group of companies we consider to be a representative peer group. Management believes that these average historical volatility rates are currently the best available indicator of future volatility.

We have adopted the "simplified method" as outlined in Staff Accounting Bulletin Topic 14 for estimating the expected term of awards. The risk free interest rate is the rate for constant yield U.S. Treasury securities with a term to maturity that is consistent with the expected term of the award.

Assumptions are reviewed each time new equity-based option awards are granted and quarterly for outstanding liability-based option awards. The assumptions used may be impacted by actual fluctuations in our stock price, movements in market interest rates and option terms. The use of different assumptions produces a different fair value for equity-based option awards and outstanding liability-based option awards and can significantly impact the amount of stock compensation expense recognized in our consolidated statement of operations. We use the Black Scholes Merton model to determine the fair value of service-based option awards and the Monte Carlo method to determine the fair value of option awards that contain a market condition. The fair value of restricted stock and restricted stock unit awards are recognized based on the fair value of our stock on the date of the grant. See "Note 8 — Stock-Based Compensation" to the consolidated financial statements in this Annual

Report on Form 10-K for further details on our stock-based compensation at December 31, 2014. Such information is incorporated herein by reference.

Income Taxes

We account for income taxes using the asset and liability approach for financial accounting and reporting. The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state taxing authorities. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and tax carryforwards. We evaluate the probability of realizing the future benefits of our deferred tax assets and provide a valuation allowance for the portion of any deferred tax assets where the likelihood of realizing an income tax benefit in the future does not meet the more likely than not criteria for recognition.

We account for uncertainty in income taxes by recognizing the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Oil and Natural Gas Reserves Quantities and Standardized Measure of Future Net Revenue

Our engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the applicable rules allow us to disclose proved, probable and possible reserves, we have elected to present only proved reserves in this Annual Report on Form 10-K. The applicable rules define proved reserves as the quantities of oil and natural 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 the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Our engineers and technical staff must make many subjective assumptions based on their professional judgment in developing reserves estimates. Reserves estimates are updated quarterly and consider recent production levels and other technical information about each well. Estimating oil and natural gas reserves is complex and is inexact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations can vary. The process also requires certain economic assumptions, including, but not limited to, oil and natural gas prices, development expenditures, operating expenses, capital expenditures and taxes. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas will most likely vary from our estimates. Accordingly, reserves estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. Any significant variance could materially and adversely affect our future reserves estimates, financial condition, results of operations and cash flows. We cannot predict the amounts or timing of future reserves revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in an impairment of assets that may be material. See "Risk Factors — Our Oil and Natural Gas Reserves Are Estimated and May Not Reflect the Actual Volumes of Oil and Natural Gas We Will Recover, and Significant Inaccuracies in These Reserves Estimates or Underlying Assumptions Will Materially Affect the Quantities and Present Value of Our Reserves."

Recent Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued Accounting Standards Update, or ASU, 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. This standard requires expanded disclosures surrounding revenue recognition and is intended to improve, and converge with international standards, the financial reporting requirements for revenue from contracts with customers. ASU 2014-09 will become effective for fiscal years beginning after December 15, 2016, i.e., in our first fiscal quarter of 2017. We are currently evaluating the impact, if any, of the adoption of this ASU on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative financial instruments, but we do not enter into derivative financial instruments for trading purposes.

Commodity price exposure. We are exposed to market risk as the prices of oil, natural gas and natural gas liquids fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our future anticipated production.

Table of Contents

We use costless (or zero-cost) collars and/or swap contracts to manage risks related to changes in oil, natural gas and natural gas liquids prices. Costless collars provide us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified period, providing downside price protection.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using purchase and sale information available for similarly traded securities. At December 31, 2014, RBC, Comerica Bank, The Bank of Nova Scotia and BMO Harris Financing (Bank of Montreal) (or affiliates thereof) were the counterparties for all of our derivative instruments. We have considered the credit standing of the counterparties in determining the fair value of our derivative financial instruments.

We have entered into various costless collar contracts to mitigate our exposure to fluctuations in oil prices, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to us pursuant to any of these oil hedging transactions is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to the calculation period’s calendar month. When the settlement price is below the price floor established by one or more of these collars, we receive from our counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil volume. When the settlement price is above the price ceiling established by one or more of these collars, we pay our counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

We have entered into various costless collar contracts to mitigate our exposure to fluctuations in natural gas prices, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to us pursuant to any of these transactions is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period’s calendar month for the settlement date of that contract period. When the settlement price is below the price floor established by one or more of these collars, we receive from our counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract natural gas volume. When the settlement price is above the price ceiling established by one or more of these collars, we pay our counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

We have entered into various swap contracts to mitigate our exposure to fluctuations in NGL prices, each with an established fixed price. For each calculation period, the settlement price for determining the realized gain or loss to us pursuant to any of these transactions is the arithmetic average of any current month for delivery on the nearby month futures contracts of the underlying commodity on the pricing date. When the settlement price is below the fixed price established by one or more of these swaps, we receive from our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume. When the settlement price is above the fixed price established by one or more of these swaps, we pay to our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume.

See “Note 11 — Derivative Financial Instruments” to the consolidated financial statements in this Annual Report on Form 10-K for a summary of our open derivative financial instruments at December 31, 2014. Such information is incorporated herein by reference.

Effect of Recent Derivatives Legislation. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which is intended to modernize and protect the integrity of the U.S. financial system. The Dodd-Frank Act, among other things, establishes federal oversight and regulation of certain derivative products including commodity hedges of the type we use. The Dodd-Frank Act requires the Commodity Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has proposed or finalized most of these regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished. Based upon the limited assessments we are able to make with respect to the Dodd-Frank Act, there is the possibility that the Dodd-Frank Act could have a substantial and adverse impact on our ability to enter into and maintain these commodity hedges. In particular, the Dodd-Frank Act could result in the implementation of position limits and additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future. See "Risk Factors — The Derivatives Legislation Adopted by Congress Could Have an Adverse Impact on Our Ability to Hedge Risks Associated with Our Business."

Interest rate risk. We do not and have not used interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense on existing debt since we borrowed under our Credit Agreement for the first time in December 2010. At December 31, 2014 we had $340.0 million in revolving borrowings outstanding under our Credit Agreement at an interest rate of approximately 3.3% per annum. If we incur additional indebtedness in the future and at higher interest rates, we may use interest rate derivatives. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition, results of operations and cash flows. In addition, our oil, natural gas and natural gas liquids derivative arrangements expose us to credit risk in the event of nonperformance by our counterparties.

While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation requires us to conduct the due diligence necessary to determine credit terms and credit limits, which may include reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, its historical payment record and the financial ability of its parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. The counterparties on our derivative financial instruments in place at February 27, 2015 were RBC, Comerica Bank, The Bank of Nova Scotia and BMO Harris Financing (Bank of Montreal) (or affiliates thereof) and we are likely to enter into any future derivative instruments with RBC, Comerica Bank, The Bank of Nova Scotia, BMO Harris Financing (Bank of Montreal) or other lenders (or affiliates thereof) party to the Credit Agreement.

Impact of Inflation. Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2014, 2013 and 2012. Although the impact of inflation has been generally insignificant in recent years, it is still a factor in the U.S. economy and we tend to specifically experience inflationary pressure on the cost of oilfield services and equipment with increases in oil and natural gas prices and with increases in drilling activity in our areas of operations, including the Eagle Ford shale play, the Wolfcamp and Bone Spring plays in the Permian Basin, and the Haynesville shale play. See "Business — General." See also "Risk Factors — The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows."

Item 8. Financial Statements and Supplementary Data.

Our financial statements appear at the end of this Annual Report on Form 10-K. See the index to the financial statements in Item 15.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.

On April 9, 2014, the Audit Committee of the Board of Directors of the Company approved the appointment of KPMG LLP ("KPMG") as the Company's independent registered public accounting firm for the year ending December 31, 2014. This appointment constituted the dismissal of Grant Thornton LLP ("Grant Thornton") as the Company's independent registered public accounting firm. Grant Thornton completed its engagement as the Company's independent registered public accounting firm for the year ended December 31, 2013 upon the filing of the Company's Annual Report on Form 10-K. The Audit Committee made its decision in connection with its annual review of the Company's independent registered public accounting firm and after soliciting proposals from several accounting firms.

Grant Thornton’s audit reports on the Company’s consolidated financial statements for the years ended December 31, 2013 and 2012 did not contain an adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope, or accounting principles.

During the years ended December 31, 2013 and 2012, and through the current date, there were no (i) disagreements (as defined in Item 304(a)(1)(iv) of Regulation S-K) between the Company and Grant Thornton on any matter of accounting principle or practice, financial statement disclosure, or auditing scope or procedure which, if not resolved to Grant Thornton’s satisfaction, would have caused it to make reference to the matter in conjunction with its report on the Company's consolidated financial statements for the relevant year, or (ii) reportable events (as defined in Item 304(a)(1)(v) of Regulation S-K).

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this Annual Report on Form 10-K, we evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2014 to ensure that (i) information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that (ii) information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2014, there were no changes in our internal controls that have materially affected or are reasonably likely to have a material effect on our internal control over financial reporting.

Management's 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) of the Exchange Act, as amended. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this Annual Report on Form 10-K based on the framework in 2013 "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

KPMG, our independent registered public accounting firm, has issued an attestation report on our controls over financial reporting as of December 31, 2014 as included herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Matador Resources Company:

We have audited Matador Resources Company's (the "Company") internal control over financial reporting as of December 31, 2014 based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) .

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of the Company and subsidiaries as of December 31, 2014, and the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the year then ended, and our report dated March 2, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Dallas, Texas
March 2, 2015

Item 9B. Other Information.

On February 26, 2015, we entered into an amendment to the Independent Contractor Agreement with David F. Nicklin and his consulting company, David F. Nicklin International Consulting, Inc. (the “Independent Contractor Agreement Amendment”). Pursuant to the Independent Contractor Agreement Amendment, the term of Mr. Nicklin’s Independent Contractor Agreement was extended to March 31, 2015 with automatic monthly extensions thereafter unless either party elects to terminate the agreement upon notice provided not less than fifteen days before the end of the then-current month. In addition, the daily rate paid to Mr. Nicklin was increased to $2,000 per full business day worked. This description of the Independent Contractor Agreement Amendment is qualified in its entirety by reference to the Independent Contractor Agreement Amendment, a copy of which is filed as an exhibit to this Annual Report on Form 10-K and is incorporated herein by reference.

On February 26, 2015 and February 27, 2015, we borrowed $15.0 million and $10.0 million, respectively, under the Credit Agreement to finance a portion of the HEYCO Merger and for our other working capital requirements and capital expenditures. As of February 27, 2015, we had $395.0 million in borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. As of February 27, 2015, the conforming borrowing base under the Credit Agreement was $375.0 million and the borrowing base under the Credit Agreement was $450.0 million. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or repay the deficit in equal installments over a period of six months. As of February 27, 2015, we had $54.4 million available for additional borrowings under the Credit Agreement. The Company anticipates borrowing additional amounts under the Credit Agreement to fund its existing working capital requirements and capital expenditures.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act, not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 11. Executive Compensation.

The information required in response to this Item 11 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

Certain information regarding securities authorized for issuance under our equity compensation plans is included under the caption “Equity Compensation Plan Information” in Part II, Item 5, above, of this Annual Report on Form 10-K and is incorporated by reference herein. Other information required in response to this Item 12 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

The information required in response to this Item 13 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14. Principal Accounting Fees and Services.

The information required in response to this Item 14 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Table of Contents

PART IV

Item 15. Exhibits and Financial Statement Schedules.

The following documents are filed as part of this Annual Report on Form 10-K:

1. Index to Consolidated Financial Statements, Report of Independent Registered Public Accounting Firm, Consolidated Balance Sheets as of December 31, 2014 and 2013, Consolidated Statements of Operations for the Years Ended December 31, 2014, 2013 and 2012, Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2014, 2013 and 2012 and Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012.
2. Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index accompanying this Annual Report on Form 10-K.

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
2.1	Agreement and Plan of Merger, by and among Matador Resources Company (now known as MRC Energy Company), Matador Holdco, Inc. (now known as Matador Resources Company) and Matador Merger Co., dated August 8, 2011 (incorporated by reference to Exhibit 2.1 to our Registration Statement on Form S-1 filed on August 12, 2011).
2.2	Agreement and Plan of Merger, dated as of January 19, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on January 20, 2015).*
2.3	Amendment No. 1 to Agreement and Plan of Merger, dated as of January 26, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (filed herewith).
2.4	Amendment No. 2 to Agreement and Plan of Merger, dated as of February 2, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (filed herewith).
2.5	Amendment No. 3 to Agreement and Plan of Merger, dated as of February 6, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (filed herewith).*
2.6	Amendment No. 4 to Agreement and Plan of Merger, dated as of February 27, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed on March 2, 2015).*
3.1	Certificate of Merger between Matador Resources Company (now known as MRC Energy Company) and Matador Merger Co. (incorporated by reference to Exhibit 3.4 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.2	Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 13, 2012).
3.3	Amended and Restated Bylaws of Matador Resources Company (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed on February 13, 2012).
3.4	Statement of Resolutions for Series A Convertible Preferred Stock (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on March 2, 2015).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to our Registration Statement on Form S-1 filed on January 19, 2012).
4.2	

	Registration Rights Agreement, dated February 27, 2015, between Matador Resources Company and HEYCO Energy Group, Inc. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on March 2, 2015).
4.3	Voting Agreement, dated February 27, 2015, between Matador Resources Company and HEYCO Energy Group, Inc. (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on March 2, 2015).
10.1†	Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.3 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.2†	Employment Agreement between Matador Resources Company and David E. Lancaster (incorporated by reference to Exhibit 10.4 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.3†	Employment Agreement between Matador Resources Company and Matthew Hairford (incorporated by reference to Exhibit 10.5 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.4†	Employment Agreement between Matador Resources Company and Bradley M. Robinson (incorporated by reference to Exhibit 10.6 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.5†	Independent Contractor Agreement between Matador Resources Company and David F. Nicklin (incorporated by reference to Exhibit 10.7 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

Table of Contents

10.6†	First Amendment to the Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.8 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.7†	First Amendment to the Employment Agreement between Matador Resources Company and David E. Lancaster (incorporated by reference to Exhibit 10.9 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.8†	First Amendment to the Employment Agreement between Matador Resources Company and Matthew Hairford (incorporated by reference to Exhibit 10.10 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.9†	First Amendment to the Employment Agreement between Matador Resources Company and Bradley M. Robinson (incorporated by reference to Exhibit 10.11 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.10†	Second Amendment to the Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.12 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.11†	Second Amendment to the Employment Agreement between Matador Resources Company and David E. Lancaster (incorporated by reference to Exhibit 10.13 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.12†	Second Amendment to the Employment Agreement between Matador Resources Company and Matthew Hairford (incorporated by reference to Exhibit 10.14 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.13†	Second Amendment to the Employment Agreement between Matador Resources Company and Bradley M. Robinson (incorporated by reference to Exhibit 10.15 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.14†	First Amendment to the Independent Contractor Agreement between Matador Resources Company and David F. Nicklin (incorporated by reference to Exhibit 10.16 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.15†	2012 Long-Term Incentive Plan of Matador Resources Company (incorporated by reference to Exhibit 10.17 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.16†	First Amendment to the Matador Resources Company 2012 Long-Term Incentive Plan dated April 16, 2012 (incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.17†	Second Amendment to the Matador Resources Company 2012 Long-Term Incentive Plan dated March 8, 2013 (incorporated by reference to Exhibit 10.17 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.18†	

	Matador Resources Company Annual Incentive Plan for Management and Key Employees (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.19†	Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated October 23, 2003 (incorporated by reference to Exhibit 10.15 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.20†	First Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated January 29, 2004 (incorporated by reference to Exhibit 10.16 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.21†	Second Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated February 3, 2005 (incorporated by reference to Exhibit 10.17 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.22†	Third Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated February 1, 2006 (incorporated by reference to Exhibit 10.18 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.23†	Fourth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated May 1, 2006 (incorporated by reference to Exhibit 10.19 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

Table of Contents

10.24†	Fifth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated February 13, 2008 (incorporated by reference to Exhibit 10.20 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.25†	Sixth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated August 5, 2008 (incorporated by reference to Exhibit 10.21 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.26†	Seventh Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated December 12, 2011 (incorporated by reference to Exhibit 10.26 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.27†	Eighth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated March 8, 2013 (incorporated by reference to Exhibit 10.27 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.28†	Form of Indemnification Agreement between Matador Resources Company and each of the directors and executive officers thereof (incorporated by reference to Exhibit 10.22 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.29	Purchase, Sale and Participation Agreement, by and between Matador Resources Company (now known as MRC Energy Company) and Orca ICI Development, JV, dated at May 16, 2011 (incorporated by reference to Exhibit 10.25 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.30	First Amendment to Purchase Sale and Participation Agreement, dated as of June 12, 2013, by and between MRC Energy Company and Orca/ICI Development (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
10.31†	Form of Non-Qualified Stock Option Agreement granted pursuant to the Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan (incorporated by reference to Exhibit 10.36 to the Annual Report on Form 10-K for the year ended December 31, 2011).
10.32†	Form of Incentive Stock Option Agreement granted pursuant to the Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan (incorporated by reference to Exhibit 10.37 to the Annual Report on Form 10-K for the year ended December 31, 2011).
10.33†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.38 to the Annual Report on Form 10-K for the year ended December 31, 2011).
10.34†	Form of Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2011).
10.35†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2011).

10.36†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.37†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.38†	Form of Performance Restricted Stock and Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.39†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.40†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).

Table of Contents

10.41†	Form of Performance Restricted Stock and Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.42	Third Amended and Restated Credit Agreement, dated as of September 28, 2012, by and among MRC Energy Company, as Borrower, the Lending Entities from time to time parties thereto, as Lenders, and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 4, 2012).
10.43	Second Amended and Restated Pledge and Security Agreement, by and among MRC Energy Company, Longwood Gathering and Disposal Systems GP, Inc. and Royal Bank of Canada, as Administrative Agent, dated as of September 28, 2012 (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.44	Second Amended, Restated and Consolidated Unconditional Guaranty, by and among MRC Permian Company, MRC Rockies Company, Matador Production Company, Longwood Gathering and Disposal Systems GP, Inc., Longwood Gathering and Disposal Systems, LP, Matador Resources Company and Royal Bank of Canada, as Administrative Agent, dated as of September 28, 2012 (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.45	First Amendment to Third Amended and Restated Credit Agreement dated as of March 11, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.46	Second Amendment to Third Amended and Restated Credit Agreement dated as of June 4, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 6, 2013).
10.47	Third Amendment to Third Amended and Restated Credit Agreement, dated as of August 7, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
10.48	Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of March 12, 2014, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2013).
10.49	Fifth Amendment to Third Amended and Restated Credit Agreement, dated as of September 5, 2014, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on September 8, 2014).
10.50†	Form of Employment Agreement between Matador Resources Company and each of Craig N. Adams and Ryan C. London (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the

	year ended December 31, 2013).
10.51†	Letter Agreement between Matador Resources Company, David F. Nicklin and David F. Nicklin International Consulting, Inc., dated February 26, 2015 (filed herewith).
10.52†	Form of Employment Agreement between Matador Resources Company and Van H. Singleton, II, effective February 5, 2015 (filed herewith).
10.53	Guaranty, dated February 27, 2015, by Matador Resources Company in favor of PlainsCapital Bank (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 2, 2015).
10.54†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (filed herewith).
10.55†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (filed herewith).
21.1	List of Subsidiaries of Matador Resources Company (filed herewith).
23.1	Consent of KPMG LLP (filed herewith).
23.2	Consent of Grant Thornton LLP (filed herewith).
23.3	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).

31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).
101	The following financial information from Matador Resources Company's Annual Report on Form 10-K for the year ended December 31, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Consolidated Financial Statements (submitted electronically herewith).
†	Indicates a management contract or compensatory plan or arrangement.
*	Pursuant to Item 601(b)(2) of Regulation S-K, the Company agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

MATADOR RESOURCES COMPANY

March 2, 2015

By: /s/ Joseph Wm. Foran
Joseph Wm. Foran
Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Joseph Wm. Foran Joseph Wm. Foran	Chairman and Chief Executive Officer (Principal Executive Officer)	March 2, 2015
/s/ David E. Lancaster David E. Lancaster	Executive Vice President, Chief Operating Officer and Chief Financial Officer (Principal Financial Officer)	March 2, 2015