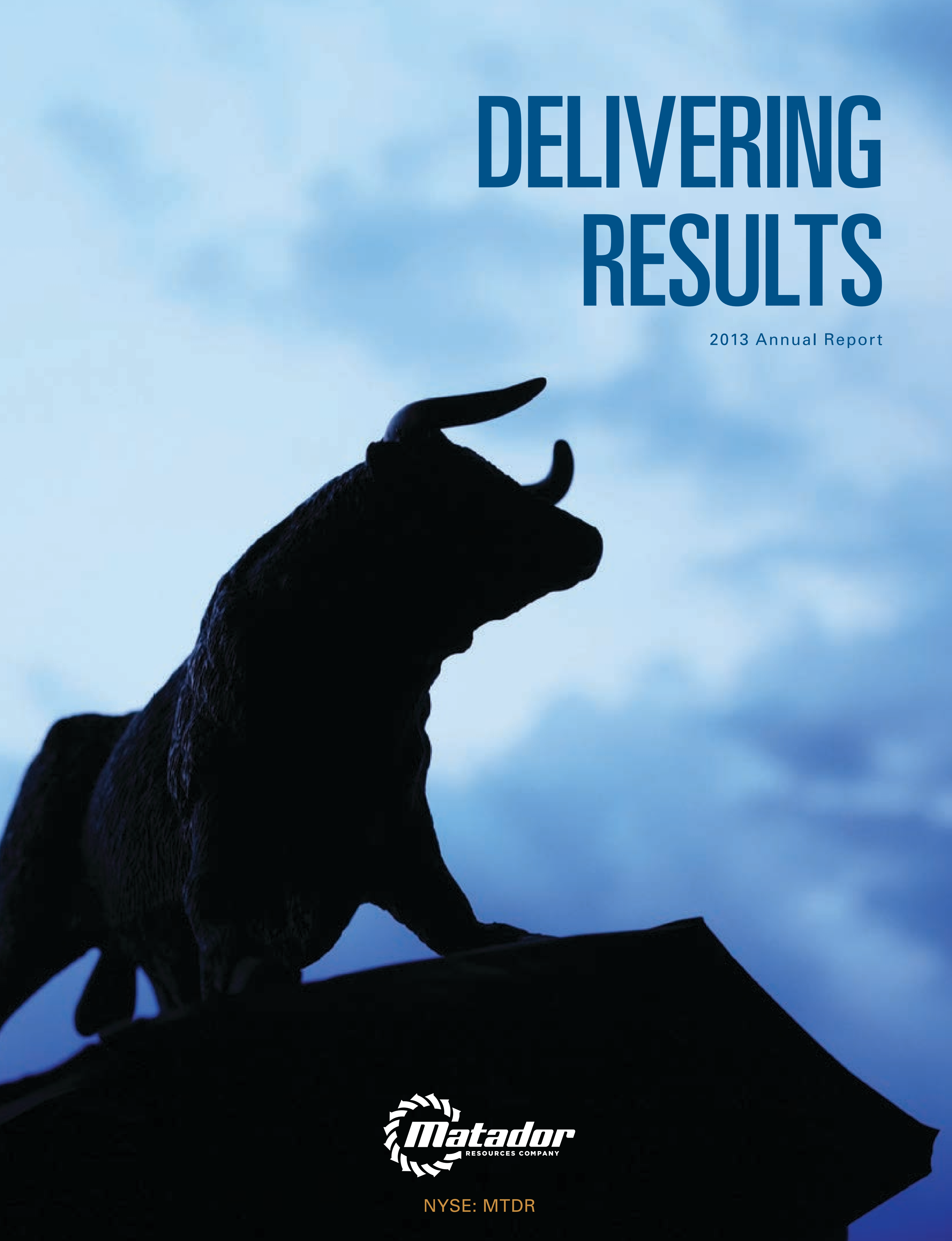
DELIVERING RESULTS

2013 Annual Report



Matador
RESOURCES COMPANY

NYSE: MTDR

MATADOR RESOURCES COMPANY is 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. Its 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. Matador also operates in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. In addition, Matador has a large exploratory leasehold position in Southwest Wyoming and adjacent areas of Utah and Idaho where it is testing the Meade Peak shale.

FINANCIAL AND OPERATING HIGHLIGHTS

($ in millions)	2011	2012	2013
Operating Data			
Oil and Natural Gas Revenues	$ 67.0	$ 156.0	$ 269.0
% Oil	22%	79%	79%
Adjusted EBITDA(1)	$ 49.9	$ 115.9	$ 191.8
Balance Sheet Data			
Cash	$ 10.3	$ 2.1	$ 6.3
Net Property and Equipment	$ 399.9	$ 591.1	$ 845.9
Total Assets	$ 439.5	$ 632.0	$ 890.3
Current Liabilities	$ 74.6	$ 96.5	$ 100.3
Long-Term Liabilities	$ 93.4	$ 156.4	$ 221.1
Total Shareholders' Equity	$ 271.5	$ 379.1	$ 568.9
Net Production Volumes			
Oil (MBbl)	154	1,214	2,133
Natural Gas (Bcf)	14.5	12.5	12.9
Total Oil Equivalent (MBOE)(2),(3)	2,573	3,294	4,285
% Oil(3)	6%	37%	50%
Average Daily Production (BOE/d)(3)	7,049	9,000	11,740
Reserves Information			
Total Proved Reserves (MBOE)(2),(3)	32,196	23,819	51,729
% Oil(3)	12%	44%	32%
PV-10(4)	$ 248.7	$ 423.2	$ 655.2

(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 "Selected Financial Data — Non-GAAP Financial Measures" in the Annual Report on Form 10-K enclosed herein.

(2) Thousands of barrels of oil equivalent.

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

(4) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "Business — Estimated Proved Reserves" in the Annual Report on Form 10-K enclosed herein.

DEAR SHAREHOLDERS & FRIENDS

2013 was another record year for Matador Resources Company. Our share price increased 127% from $8.20 on December 31, 2012 to $18.64 on December 31, 2013. We increased oil production 76% from 1.2 million barrels in 2012 to 2.1 million barrels in 2013. This growth in oil production, together with technical improvements in our drilling and completion operations, helped increase our total Adjusted EBITDA 65% from $115.9 million in 2012 to $191.8 million in 2013 as we were drilling better wells for less money. We also grew our proved oil reserves 56% from 10.5 million barrels of oil at the end of 2012 to 16.4 million barrels at the end of 2013. This increase in value, together with the proceeds from an equity offering in September, caused our market capitalization to increase almost three-fold to $1.2 billion at the end of 2013. Details of these achievements and much more information about Matador and our 2013 performance are provided in the enclosed Annual Report on Form 10-K.

DELIVERING RESULTS

When Matador completed its initial public offering two years ago, we were committed to becoming a more balanced company by growing oil production and oil reserves attributable to our Eagle Ford assets and developing a third area of interest to complement our properties in the Haynesville and the Eagle Ford. During 2013, Matador delivered on both of these commitments. First, we focused our operational efforts on growing and developing our assets in the Eagle Ford. Matador allocated 70% of its 2013 capital expenditures to its operations in South Texas, and Matador completed and began producing oil and natural gas from 27.6 net wells in this area. In addition, we added 1,660 net acres to our Eagle Ford acreage position, providing more new locations than we drilled during 2013.

Second, we established a third core area, acquiring 38,900 net acres during 2013 in the Permian Basin and increasing our total position in the area to approximately 44,800 net acres as of December 31, 2013. We consider this acreage highly prospective for oil, and we began exploration efforts in this area during 2013. The initial results from our first three wells have exceeded our expectations and led to our decision to run one rig continuously in the Delaware portion of the Permian Basin throughout 2014, which should contribute significantly to our results this year.

FORWARD PROGRESS

During 2013, we were focused on improving drilling times and frac results in the Eagle Ford, and this effort will continue in 2014. We have begun to drill on our western Eagle Ford acreage from batch drilled pads, using a "walking" drilling rig. As a result, we have improved both drilling times and costs. We have realized cost savings of approximately $325,000 per well on wells drilled using this rig, and we expect the use of this technique will lead to total cost savings of approximately $400,000 per well or more going forward. In addition, our sixth generation fracs have helped increase oil and natural gas recoveries. The development of our Eagle Ford properties will continue to be the primary driver of our growth in 2014.

With the acquisition of our Permian Basin position, the objective of our 2014 drilling program in this area is to better evaluate and delineate this acreage in an effort to define an expanded drilling program for 2015 and beyond. We believe our acreage position should increase in value as Matador validates these leases with productive wells.

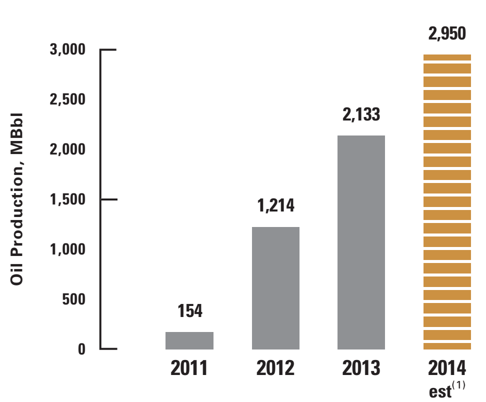
RETAINING THE CULTURE

Matador has always enjoyed special relationships with our shareholders, and as we continue to grow, we hope this will never change. I want to personally invite all of you to attend the shareholders' meeting scheduled for 9:30 a.m. CDT on June 4, 2014, in Dallas. Last year we had record attendance and hope this year's gathering will be even better. We encourage all of our shareholders — legacy, prospective and new — to come to Dallas and to attend this meeting. Please accept this letter, our Annual Report and the accompanying proxy materials as our special invitation to each of you to attend this meeting, to visit with us and to hear directly the update on our plans and progress. It has been a pleasure to serve you in our thirty-first year of working together to increase our stock value and to build a great company with quality properties, a quality board and staff and a quality investor group!

Yours Truly,

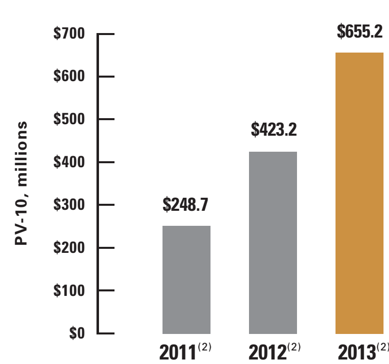
JOSEPH WM. FORAN
Chairman and Chief Executive Officer

GROWTH IN OIL PRODUCTION



(1) 2014 oil production estimated at mid-point of 2014 guidance.

GROWTH IN PV-10[1] FROM PROVED RESERVES



(1) PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "Business — Estimated Proved Reserves" in the Annual Report on Form 10-K enclosed herein.

(2) At December 31 of each respective year.

BOARD OF DIRECTORS

(Left to right) Carlos M. Sepulveda, Jr.; Michael C. Ryan; Gregory E. Mitchell; Joseph Wm. Foran; David M. Laney; Margaret B. Shannon; Steven W. Ohnimus; Stephen A. Holditch

BOARD OF DIRECTORS

Joseph Wm. Foran
Founder, Chairman and Chief Executive Officer of Matador Resources Company (Matador II); Founder and Chief Executive Officer of Matador Petroleum Corporation (Matador I)

David M. Laney
Lead Director; Past Chairman, Amtrak Board of Directors; Former Partner, Jackson Walker LLP

Gregory E. Mitchell
Director; President and CEO, Toot'n Totum Food Stores

Dr. Steven W. Ohnimus
Director; Retired VP and General Manager, Unocal Indonesia

Michael C. Ryan
Director; Partner, Berens Capital Management

Carlos M. Sepulveda, Jr.
Director; Chairman of the Board, Triumph Bancorp, Inc.;
Director and Audit Chair, Cinemark Holdings, Inc.;
Director, Interstate Battery System International, Inc.;
Director, Savoya, LLC

Margaret B. Shannon
Director; Retired VP and General Counsel, BJ Services Co.

Dr. Stephen A. Holditch
Director; Professor Emeritus and Former Head of Dept. of Petroleum Engineering, Texas A&M University;
Founder and Former President, S.A. Holditch & Associates;
Past President of Society of Petroleum Engineers;
Member of the National Academy of Engineering;
Anthony F. Lucas Technical Leadership Gold Medal and Lester C. Uren Technical Excellence Award from SPE

SPECIAL BOARD ADVISORS

Marlan W. Downey
Retired President, ARCO International;
Former President, Shell Pecten International;
Past President of American Association of Petroleum Geologists;
Sidney Powers Medalist from AAPG

Wade I. Massad
Managing Member, Cleveland Capital Management, LLC;
Former EVP – Capital Markets, Matador Resources Company;
Formerly with RBC Capital Markets and KeyBanc Capital Markets

Edward R. Scott, Jr.
Former Chairman, Amarillo Economic Development Corporation;
Law Firm of Gibson, Ochsner & Adkins, Retired

W.J. "Jack" Sleeper, Jr.
President and Chief Operating Officer, DeGolyer and MacNaughton, Worldwide Petroleum Consulting, Retired

Matador RESOURCES COMPANY

MTDR LISTED NYSE

MATADOR STAFF

Surrounding Joe Foran, Matador's Chairman and CEO (front, middle), are members of Matador's senior staff. We had a total of 66 full-time employees at December 31, 2013.

EXECUTIVE OFFICERS AND SENIOR MANAGEMENT

Joseph Wm. Foran
Founder, Chairman and Chief Executive Officer

Matthew V. Hairford
President

David E. Lancaster
Executive Vice President, Chief Operating Officer and Chief Financial Officer

David F. Nicklin
Executive Director of Exploration

Craig N. Adams
Executive Vice President – Land & Legal

Ryan C. London
Vice President and General Manager

Bradley M. Robinson
Vice President of Reservoir Engineering and Chief Technology Officer

Billy E. Goodwin
Vice President of Drilling

William F. McMann
Vice President of Production & Facilities

Van H. Singleton, II
Vice President of Land

G. Gregg Krug
Vice President of Marketing

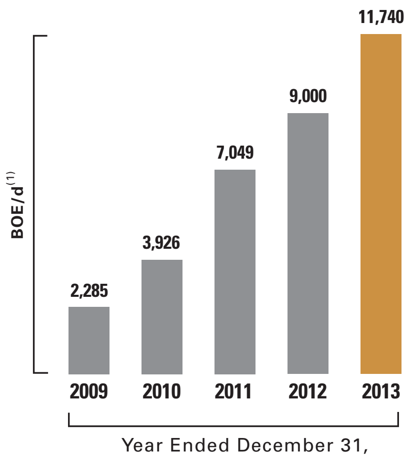
Sandra K. Fendley
Vice President and Chief Accounting Officer

Kathryn L. Wayne
Controller and Treasurer

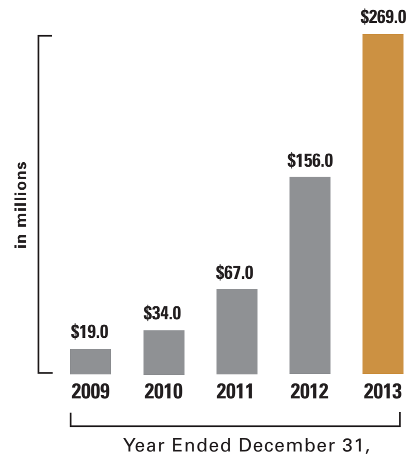
MATADOR RESOURCES COMPANY EMPLOYEE ACCOMPLISHMENTS

- Technical team has been directly involved in over 25 different horizontal well drilling and/or operations programs in both onshore and offshore formations worldwide
- Engineering and geologic staff have examined 100 basins and reservoirs across five continents
- Technical team has written over 130 papers
- Technical team has in-depth experience with various horizontal well completion techniques and their applications in multiple unconventional plays
- Brad Robinson, recipient of 2013 Completions Optimization and Technology award presented by the Mid-Continent region of the Society of Petroleum Engineers (SPE)
- Steven Sinclair, co-recipient of Energy Minerals Division's President's Certificate for Excellence in Presentations presented by the American Association of Petroleum Geologists (AAPG) for best paper at the 2013 AAPG Annual Convention

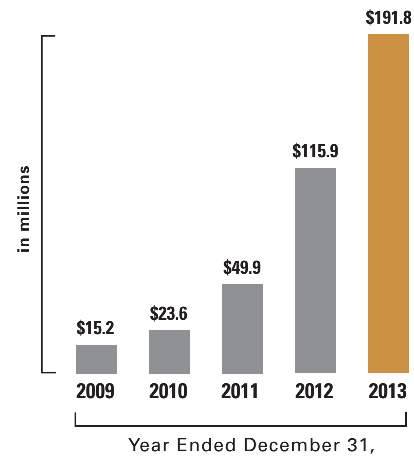
AVERAGE DAILY OIL EQUIVALENT PRODUCTION



TOTAL OIL AND NATURAL GAS REVENUES



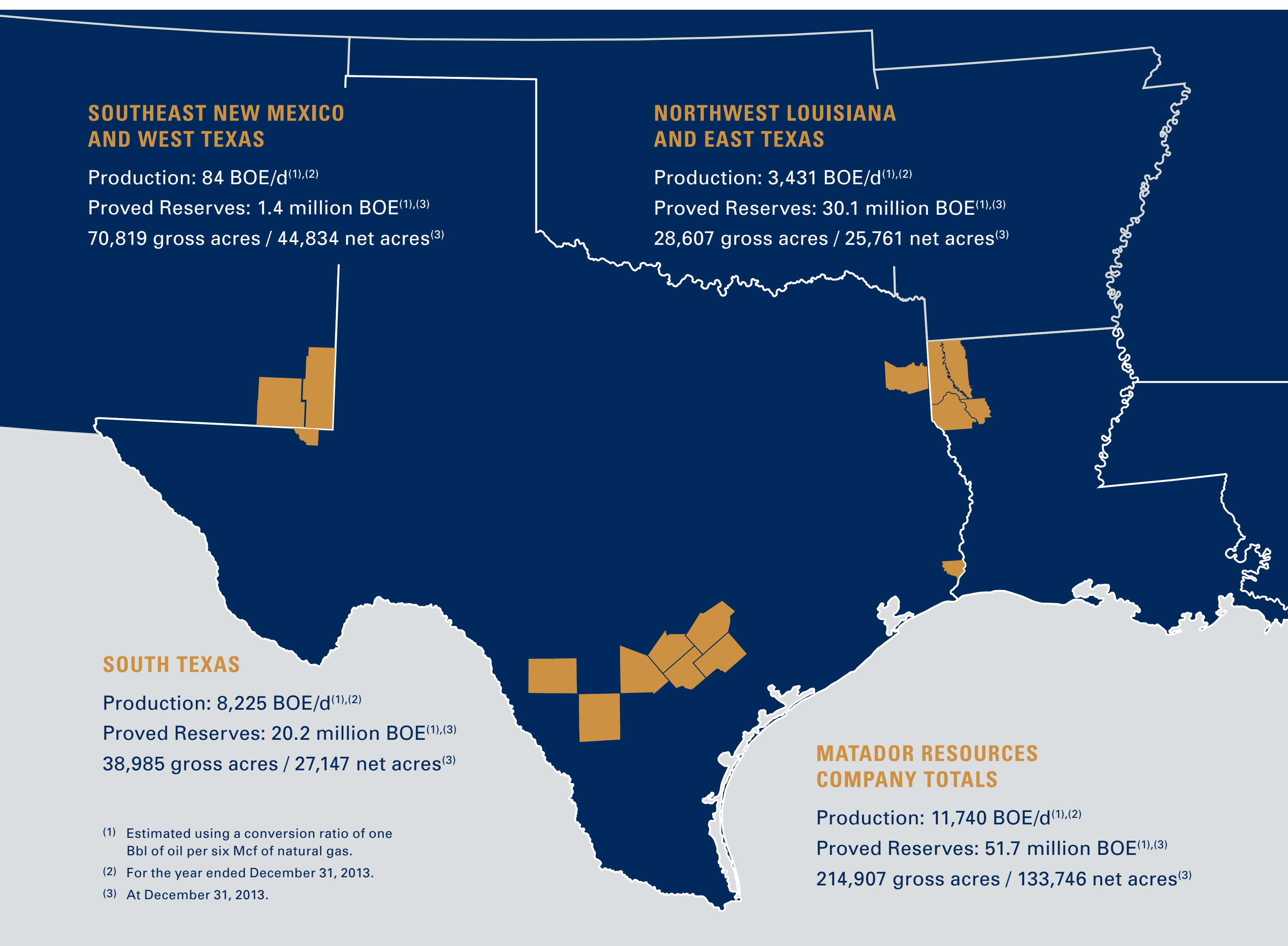
ADJUSTED EBITDA[2]



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

(2) 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" in the Annual Report on Form 10-K enclosed herein.

AREAS OF OPERATION



SOUTHEAST NEW MEXICO AND WEST TEXAS

Production: 84 BOE/d[1,2]

Proved Reserves: 1.4 million BOE[1,3]

70,819 gross acres / 44,834 net acres[3]

NORTHWEST LOUISIANA AND EAST TEXAS

Production: 3,431 BOE/d[1,2]

Proved Reserves: 30.1 million BOE[1,3]

28,607 gross acres / 25,761 net acres[3]

SOUTH TEXAS

Production: 8,225 BOE/d[1,2]

Proved Reserves: 20.2 million BOE[1,3]

38,985 gross acres / 27,147 net acres[3]

MATADOR RESOURCES COMPANY TOTALS

Production: 11,740 BOE/d[1,2]

Proved Reserves: 51.7 million BOE[1,3]

214,907 gross acres / 133,746 net acres[3]

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

(2) For the year ended December 31, 2013.

(3) At December 31, 2013.

DELIVERING RESULTS

2013 FORM 10-K

Matador
RESOURCES COMPANY

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2013

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 ☐ 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 ☑

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 ☑ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☑
Non-accelerated filer ☐ (Do not check if 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 ☑

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 $593,728,477.

As of March 13, 2014, there were 65,744,878 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 2014 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

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

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 before the completion of our corporate reorganization on August 9, 2011 and Matador Holdco, Inc. and its subsidiaries after the completion of our corporate reorganization on August 9, 2011. Prior to August 9, 2011, Matador Holdco, Inc. was a wholly-owned subsidiary of Matador Resources Company, now known as MRC Energy Company. Pursuant to the terms of our corporate reorganization, former Matador Resources Company became a wholly-owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name 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. In addition, we have a large exploratory leasehold position in Southwest Wyoming and adjacent areas of Utah and Idaho where we are testing the Meade Peak shale.

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 exploration and development activity on our Eagle Ford acreage in South Texas;
- explore and develop our Wolfcamp and Bone Spring acreage in the Permian Basin;
- identify, evaluate and develop oil and natural gas plays to maintain a balanced portfolio;
- continue to improve operational and cost efficiencies;
- maintain our financial discipline; and
- pursue opportunistic acquisitions.

The successful execution of our business strategies in 2013 led to significant increases in our oil and natural gas revenues and Adjusted EBITDA, oil production and proved oil and natural gas reserves, and the associated increase in the PV-10 of our proved reserves. We also significantly increased our leasehold position in the Permian Basin and added to our acreage positions in the Eagle Ford shale and the Haynesville 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."

2013 HIGHLIGHTS

Increased Oil and Natural Gas Revenues and Adjusted EBITDA

Our oil and natural gas revenues for the year ended December 31, 2013 were the highest achieved in any fiscal year in the Company's history. Our oil and natural gas revenues increased $113.0 million to $269.0 million in 2013, which represents an increase of 72% from 2012. This revenue increase was primarily driven by a significant increase in our oil production in 2013 and a higher weighted average natural gas price realized in 2013. Our Adjusted EBITDA of $191.8 million for 2013 was an increase of 65%, as compared to our Adjusted EBITDA of $115.9 million for 2012. 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 and Oil Equivalent Production

Our total oil production and our average daily oil equivalent production for the year ended December 31, 2013 were the best in our history. In 2013, we produced 2.1 million barrels of oil, an increase of 76%, as compared to 1.2 million barrels of oil produced in 2012. Our average daily oil equivalent production was 11,740 BOE per day, including 5,843 Bbl of oil per day and 35.4 MMcf of natural gas per day, an increase of 30%, as compared to 9,000 BOE per day, including 3,317 Bbl of oil per day and 34.1 MMcf of natural gas per day, for the year ended December 31, 2012. This increase in oil production was a direct result of our drilling operations in the Eagle Ford shale. We achieved this increased oil production despite having as much as 15% to 20% of our production capacity shut in at various times during 2013, as we continued our operational practices of pad and batch drilling in the Eagle Ford shale and shutting in producing wells while conducting drilling and completion operations on offsetting wells. Oil production comprised 50% 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, 2013, as compared to 37% for the year ended December 31, 2012 and 6% for the year ended December 31, 2011.

Increased Oil and Natural Gas Reserves

At December 31, 2013, our estimated total 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, which is an increase of 117% from December 31, 2012. The associated PV-10 of our estimated total proved oil and natural gas reserves increased 55% to $655.2 million at December 31, 2013 from $423.2 million at December 31, 2012. 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 56% to 16.4 million Bbl at December 31, 2013, as compared to 10.5 million Bbl at December 31, 2012. This growth in oil reserves was primarily attributable to our drilling program in the Eagle Ford shale during 2013. Our proved natural gas reserves increased 165% to 212.2 Bcf at December 31, 2013 from 80.0 Bcf at December 31, 2012. This large increase in proved natural gas reserves was attributable to our drilling and completion activities and improvements in natural gas prices in 2013. As a result of the continued improvement in natural gas prices during 2013, we re-classified Haynesville shale natural gas volumes previously removed from our proved reserves in 2012 as proved undeveloped reserves in 2013 and also included additional Haynesville shale proved undeveloped natural gas reserves in our total proved reserves at December 31, 2013.

At December 31, 2013, proved developed reserves included 8.3 million Bbl of oil and 53.5 Bcf of natural gas, and proved undeveloped reserves included 8.1 million Bbl of oil and 158.7 Bcf of natural gas. Proved developed reserves comprised 33% and proved oil reserves comprised 32% of our total proved oil and natural gas reserves, respectively, at December 31, 2013. Based on our 2013 year-end total proved reserves and our 2013 oil equivalent production of 4.3 million BOE, we improved our reserves/production (“R/P”) ratio to 12.1 years at December 31, 2013, as compared to 7.2 years at December 31, 2012.

Operational Efficiencies

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 two 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 from batch drilled pads using a drilling rig equipped with a “walking” package and, as a result, we have improved both drilling times and costs. We have realized cost savings of approximately $325,000 per well on initial wells drilled using this rig, and we expect the use of batch drilling and the “walking” rig will lead to total cost savings of approximately $400,000 per well or more going forward. Recent wells drilled on our western Eagle Ford acreage in La Salle County, Texas have drilling times from spud to total depth of eight to 10 days per well and costs at or just below $6 million per well. In April 2014, we expect to replace the drilling rig currently operating in the central portion of our acreage in Karnes and Wilson Counties, Texas with a new “walking” rig. At that time, we will have two “walking” rigs operating in the Eagle Ford and will conduct batch drilling operations on our properties using these rigs for the balance of 2014. Recent wells in our central Eagle Ford acreage have been drilled for between $7.0 and $7.5 million, but we expect to see further cost improvements with the initiation of batch drilling operations in this area as well. We anticipate that we will drill almost 250,000 lateral feet with two rigs in the Eagle Ford in 2014, as compared to 150,000 feet using two rigs in 2012 and effectively 1.5 rigs in 2013, an increased drilling efficiency of almost 70%.

During 2013, we continued to refine the design of our hydraulic fracture treatments to enhance well productivity and ultimate hydrocarbon recovery, increasing fluid volumes to 40 Bbl per foot and proppant volumes to more than 2,000 pounds per foot, while decreasing the spacing between perforation clusters where the fractures are initiated. These Generation 5, and now Generation 6, fracture treatments are resulting in significant improvements in initial well productivity as compared to earlier generation treatment designs. We also believe that initiating the use of gas lift relatively 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.

Acreage Acquisitions

During 2013, we acquired approximately 55,400 gross (38,900 net) acres in the Permian Basin in Southeast New Mexico and West Texas. These acreage acquisitions brought our total Permian Basin acreage position to approximately 70,800 gross (44,800 net) acres as of December 31, 2013. Between January 1 and December 31, 2013, we also acquired approximately 1,720 gross (1,660 net) acres in the Eagle Ford shale play in South Texas and approximately 1,190 gross (1,190 net) acres in the Haynesville shale play in Northwest Louisiana.

Issuance of Common Stock

In April 2013, we filed with the SEC a universal shelf registration statement on Form S-3 (the "Shelf Registration Statement"), which provided us with the ability to offer and sell up to $300 million of debt and equity securities, subject to market conditions and our capital needs. The SEC declared the Shelf Registration Statement effective on May 9, 2013. As of December 31, 2013, we had approximately $151 million of securities available for issuance under the Shelf Registration Statement.

On September 10, 2013, we completed an underwritten public offering of 9,775,000 shares of our common stock and received net proceeds of approximately $141.7 million. The net proceeds from this offering were used to fund a portion of our capital expenditures, including the addition of a third rig to our drilling program and the acquisition of additional acreage in the Eagle Ford shale, the Permian Basin and the Haynesville shale. Pending such uses, we used a portion of the net proceeds to repay $130.0 million in outstanding borrowings under our third amended and restated credit agreement (the "Credit Agreement") in September 2013, which amounts may be reborrowed in accordance with the terms of that facility for, among other items, the uses contemplated above.

RECENT DEVELOPMENTS

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 based on the lenders' review of our proved oil and natural gas reserves at December 31, 2013. At that time, we also amended our Credit Agreement to include Wells Fargo Bank, N.A., which replaced Capital One, N.A., in our lending group, which also includes Royal Bank of Canada, as administrative agent, Comerica Bank, Citibank, N.A., The Bank of Nova Scotia, SunTrust Bank, BMO Harris Financing, Inc. (Bank of Montreal) and IberiaBank. At March 13, 2014, we had $250.0 million in borrowings and $0.3 million in letters of credit outstanding under our Credit Agreement.

Between January 1 and March 13, 2014, we acquired an additional 7,000 gross (5,300 net) acres in Southeast New Mexico and West Texas, bringing our total Permian Basin acreage position to 77,800 gross (50,100 net) acres as of March 13, 2014.

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 Haynesville shale play in Northwest Louisiana and most recently, the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas. During 2013, we devoted most of our efforts and most of our capital investment to our drilling operations in the Eagle Ford shale in South Texas 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, 2013, essentially all of our efforts are focused on unconventional plays.

At December 31, 2013, 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, the Haynesville shale play, as well as the traditional Cotton Valley and Hosston (Travis Peak) formations, in Northwest Louisiana and East Texas, and the Meade Peak shale play in Southwest Wyoming and the adjacent areas of Utah and Idaho.

The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2013:

	Net Acreage	Producing Wells		Total Identified Drilling Locations(1)		Estimated Net Proved Reserves(2)		Avg. Daily Production (BOE/d)(3)
		Gross	Net	Gross	Net	MBOE(3)	% Developed	
South Texas:								
Eagle Ford (4)	27,147	73	63.3	273	229.3	20,221	54.9	8,225
NW Louisiana/E Texas:								
Haynesville	14,969	140	13.0	527	114.5	28,797	14.9	2,831
Cotton Valley (5)	21,821	100	63.7	71	49.3	1,339	100.0	600
Area Total (6)	25,761	240	76.7	598	163.8	30,136	18.7	3,431
Permian Basin:								
SE New Mexico, West Texas (7)	44,834	13	5.0	241	177.7	1,372	31.1	84
Other:								
Wyoming, Utah, Idaho	36,004	—	—	—	—	—	—	—
Total	133,746	326	145.0	1,112	570.8	51,729	33.2	11,740

(1) Identified and engineered drilling locations. These locations have been identified for potential future drilling and were not producing at December 31, 2013. 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, 2013, these engineered drilling locations included 52 gross (39.8 net) locations to which we have assigned proved undeveloped reserves in the Eagle Ford, four gross (3.4 net) locations to which we have assigned proved undeveloped reserves in the Wolfcamp or Bone Spring plays in the Permian Basin and 125 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, 2013.

(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 or Avalon shale plays on our acreage in the Permian Basin at December 31, 2013.

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 and others. At December 31, 2013, we were the operator for approximately 90% of our Eagle Ford acreage and 70% 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 a subsidiary of Chesapeake Energy Corporation. We also operate 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.

From time to time, we enter into joint operating agreements with our co-working interest partners governing operations on certain of our jointly owned wells and properties. Particularly when our working interest is small, however, we do not always enter into formal operating agreements with the operators, and in such cases, we rely on applicable legal and statutory authority to govern our business arrangement in accordance with industry standard practices. Where we do have joint operating agreements with affiliates of other companies, these agreements call for significant penalties should we elect not to participate in the drilling and completion of a well proposed by the operator, or a non-consent well. These non-consent penalties typically allow the operator to recover up to 400% of its costs to drill, complete and equip the non-consent well from the well's future net revenue prior to us being allowed to participate in the non-consent well for our original working interest. Ultimately, the amount of these penalties may result in us having no participation at all in the non-consent well. We also have the right to propose wells under these joint operating agreements, and the same non-consent penalties apply to the operator should it elect not to consent to a well that we propose.

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, 2013, our properties included approximately 39,000 gross (27,100 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 87% 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 82% of our Eagle Ford acreage was held by production at December 31, 2013, and approximately 97% of our Eagle Ford acreage was either held by production at December 31, 2013 or not burdened by lease expirations before 2015. During the year ended December 31, 2013, we acquired approximately 1,720 gross (1,660 net) acres in the Eagle Ford shale play that we consider to be prospective primarily for oil production. This acreage essentially replaced the acreage upon which we drilled and established oil and natural gas production and reserves during 2013.

At December 31, 2013, we had 73 gross (63.3 net) wells producing from the Eagle Ford shale in South Texas. We had drilled and completed a total of 61 gross (59.5 net) Eagle Ford wells on our operated properties, and we had also participated in 12 gross (3.8 net) Eagle Ford wells with co-working interest owners on certain of our non-operated Eagle Ford properties.

During 2013, approximately 70% of our total capital expenditures of $373.5 million were directed to our operations in South Texas, and almost entirely in the Eagle Ford shale, as we continued executing our strategy to significantly increase our oil production and oil reserves. During the first quarter of 2013, we had two contracted drilling rigs operating full-time in South Texas and all of our operated drilling and completion activities were focused on the Eagle Ford shale. In late April 2013, we moved one of these contracted drilling rigs to Southeast New Mexico, while the second contracted drilling rig continued to operate in the Eagle Ford shale. In mid-August 2013, we added a third contracted drilling rig to our drilling program and returned to operating two contracted drilling rigs in the Eagle Ford shale play. We expect to operate two contracted drilling rigs in South Texas throughout 2014. At March 13, 2014, one of our two Eagle Ford rigs was operating in southern Wilson County, Texas, while the other was operating in La Salle County, Texas. The development of our Eagle Ford shale properties in South Texas will continue to be the primary driver of our growth in 2014, and we intend to direct approximately $318.4 million, or 72%, of our estimated 2014 capital expenditure budget of $440.0 million to our operations in South Texas.

During the year ended December 31, 2013, we completed and began producing oil and natural gas from 32 gross (27.6 net) Eagle Ford shale wells drilled on our acreage position in South Texas, including 25 gross (25.0 net) operated and seven gross (2.6 net) non-operated wells. As we completed and began producing oil and natural gas from these wells during 2013, our Eagle Ford production increased significantly. For the year ended December 31, 2013, 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 produced from the Eagle Ford shale. Almost all of our oil production in 2013 and 2012 was attributable to the Eagle Ford shale. The Eagle Ford shale contributed approximately 98% of our daily oil production and approximately 42% of our daily natural gas production during 2013, as compared to approximately 98% of our daily oil production and approximately 12% of our daily natural gas production during 2012. During the year ended December 31, 2012, approximately 44% of our daily production, or 3,928 BOE per day, including 3,261 Bbl of oil per day and 4.0 MMcf of natural gas per day, was attributable to the Eagle Ford shale. During the year ended December 31, 2011, only about 8% of our daily 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, 2013, approximately 39% of our estimated total proved oil and natural gas reserves, or 20.2 million BOE, was attributable to the Eagle Ford shale, including approximately 15.2 million Bbl of oil and 30.1 Bcf of natural gas. Our proved reserves attributable to the Eagle Ford shale increased approximately 41% to 20.2 million BOE for the year ended December 31, 2013, as compared to 14.4 million BOE for the year ended December 31, 2012. Our Eagle Ford proved reserves at December 31, 2013 comprised approximately 93% of our proved oil reserves and 14% of our proved natural gas reserves, as compared to approximately 99% of our proved oil reserves and 30% of our proved natural gas reserves at December 31, 2012. The PV-10 of our proved reserves in the Eagle Ford shale at December 31, 2013 was $540.4 million, or approximately 82% of the PV-10 of our total proved reserves of $655.2 million. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "— Estimated Proved Reserves."

At December 31, 2013, we have identified and engineered 273 gross (229.3 net) 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 criteria. Of the 273 gross (229.3 net) engineered locations identified for potential future drilling in the Eagle Ford shale at December 31, 2013, we consider 150 gross (125.9 net) locations to be Tier 1 locations. We define Tier 1 Eagle Ford locations as those locations that we anticipate to have estimated ultimate recoveries of 225,000 Bbl of oil or greater. Of these Tier 1 locations, 114 gross (111.5 net) locations would be operated by us. These identified locations presume that we will be able to develop our Eagle Ford properties on 40-acre to 80-acre spacing, depending on the specific property and the wells we have already drilled. As a result of the initial performance of test wells drilled on 40-acre and 50-acre spacing during 2013, we anticipate that Eagle Ford shale wells on our acreage in central and northern La Salle County, northern Karnes County and southern Wilson County can be developed on 40-acre spacing, while our other properties may be more likely developed on 80-acre spacing. We are currently drilling on 40-acre spacing on most of our properties in central and northern La Salle County, northern Karnes County and southern Wilson County. On our properties in the eastern portion of our Eagle Ford acreage in DeWitt County, we continue to drill on 80-acre spacing with no plans to test less than 80-acre spacing at December 31, 2013, because we believe that higher permeability, better transmissibility and higher pressure in these areas make these properties less conducive to reduced spacing.

We define Tier 2 Eagle Ford locations, including 123 gross (103.4 net) locations, as those locations that we anticipate to have estimated ultimate recoveries of between 150,000 Bbl and 225,000 Bbl of oil, locations that are primarily prospective for natural gas or locations with lesser estimates of ultimate oil recovery, but on properties already held by existing production. At December 31, 2013, Tier 2 locations were identified primarily on our acreage in Zavala County, southern La Salle County and eastern Gonzales County. We have identified no potential future Eagle Ford drilling locations on our Atascosa County acreage. All of these Tier 2 locations would be operated by us, and almost all of these locations are on properties already held by production from the Eagle Ford or other producing horizons. Although we have no plans to drill any of these Tier 2 locations in 2014, as long as these properties remain held by production, or remain in the primary terms of the leases, these locations remain available for us to drill at a later time should commodity prices improve, drilling and completion costs decline further or new technologies be developed that increase expected recoveries. Certain of these properties, such as our properties in Zavala and Atascosa Counties, also offer the opportunity to explore horizons other than the Eagle Ford, including the Austin Chalk, Buda, Edwards or Pearsall, and we may develop new prospects on these properties in the future. We have included one test of the Buda formation on our Zavala County acreage as part of our 2014 capital expenditure budget. As we explore and develop all of our Eagle Ford acreage further, we believe it is possible that we may identify additional locations for future drilling. At December 31, 2013, these 273 gross (229.3 net) potential future drilling locations included 52 gross (39.8 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 two 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 from batch drilled pads using a drilling rig equipped with a "walking" package and, as a result, we have improved both drilling times and costs. We realized cost savings of approximately $325,000 per well on initial wells drilled using this rig, and we expect the use of batch drilling and the "walking" rig will lead to total cost savings of approximately $400,000 per well or more going forward. Recent wells drilled on our western Eagle Ford acreage in La Salle County have drilling times from spud to total depth of eight to 10 days per well and costs at or just below $6 million per well. In April 2014, we expect to replace the drilling rig currently operating in the central portion of our acreage in Karnes and Wilson Counties with a new "walking" rig. At that time, we will have two "walking" rigs operating in the Eagle Ford and will conduct batch drilling operations on our properties using these rigs for the balance of 2014. Recent wells in our central Eagle Ford acreage have been drilled for between $7.0 and $7.5 million, but we expect to see further cost improvements with the initiation of batch drilling operations in this area as well. We anticipate that we will drill almost 250,000 lateral feet with two rigs in the Eagle Ford in 2014, as compared to 150,000 feet using two rigs in 2012 and effectively 1.5 rigs in 2013, an increased drilling efficiency of almost 70%.

During 2013, we continued to refine the design of our hydraulic fracture treatments to enhance well productivity and ultimate hydrocarbon recovery, increasing fluid volumes to 40 Bbl per foot and proppant volumes to more than 2,000 pounds per foot, while decreasing the spacing between perforation clusters where the fractures are initiated. These Generation 5, and now Generation 6, fracture treatments are resulting in significant improvements in initial well productivity as compared to earlier generation treatment designs. We also believe that initiating the use of gas lift relatively 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.

As we continue to explore and develop our leasehold positions in the Eagle Ford shale, we may face challenges with establishing operations in new areas and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to process, transport and market the oil and natural gas we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure on our leases throughout the area. We believe that we have successfully secured the necessary drilling and completion services for our current Eagle Ford operations. We did not experience difficulties in securing completion, and in particular hydraulic fracturing, services for our newly drilled wells during 2013 or 2012, although we experienced these problems at various times during 2011 in South Texas and may have such difficulties again in the future. We believe that maintaining reliable and timely drilling and completion services and optimizing drilling and completion costs will be essential to the successful development and profitability of the Eagle Ford shale play. See "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."

In the past, we have experienced pipeline and natural gas processing interruptions and capacity and infrastructure constraints associated with natural gas production, which have, among other things, required us to flare natural gas occasionally. To alleviate a portion of the interruptions and processing capacity constraints we experienced during 2012, 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. No assurance can be made that this agreement will alleviate these issues completely, and if we were required to shut in or flare 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. 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."

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, the Austin Chalk formation, which is a naturally fractured carbonate typically ranging in thickness from 200 to 400 feet, and the Buda formation, which is a naturally fractured carbonate typically ranging in thickness from 90 to 160 feet, have produced from several fields on or nearby portions of our acreage. We believe that approximately 21,000 gross (16,800 net) acres of our properties in South Texas are prospective for the Austin Chalk and 17,200 gross (13,300 net) acres are prospective for the Buda formation, which have historically been targeted by operators in South Texas.

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 are 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 March 13, 2014, we were evaluating a series of seismic attributes which 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, 2013, we had not included any Buda locations in our future drilling locations, although we do plan to drill one gross (1.0 net) exploratory well to test the Buda formation on our Glasscock Ranch property in 2014. We participated in one non-operated test of the Buda formation in South Texas (approximately 21% working interest) on one of our leases in Atascosa County during the first quarter of 2013. This well tested a strong initial oil flow from a very short horizontal lateral, but the well was plugged and abandoned after oil production from this interval declined to uneconomic levels soon thereafter. We do not expect to participate in any additional Buda tests on our Atascosa County acreage during 2014.

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 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.

One example of such an opportunity appears to be the so-called “Wolf-Bone” play in the western Permian Basin. Together, the Lower Permian age Bone Spring (also called Leonardian) and Wolfcamp shale formations span several thousand feet of stacked shales, sandstones, limestones and dolomites, representing complex and dynamic submarine depositional systems that include several organic rich source rocks. Throughout these intervals, oil and natural gas have been produced primarily from conventional sandstone and carbonate reservoirs even though hydrocarbons are trapped in the tight sands, limestones and dolomites interbedded within organic rich shale. Recently, these hydrocarbon-bearing zones have been recognized and tested by a number of operators as targets for horizontal drilling and multi-stage hydraulic fracturing techniques. As a result, many industry players are expanding positions and conducting drilling programs throughout the western Permian Basin in Lea and Eddy Counties in Southeast New Mexico and Loving, Pecos, Reeves, Ward and Winkler Counties in West Texas. In addition, other industry players have been successful in developing similar formations on the eastern side of the Permian Basin, east of the Central Basin Platform in West Texas. Multiple horizontal drilling and completion targets are being identified and tested by companies throughout the vertical section including the Delaware, Avalon, Bone Spring (First, Second and Third sands) and multiple intervals within the Wolfcamp shale, often identified as the Wolfcamp “A” through “D” intervals.

During 2013, we added significantly to our acreage position and initiated an exploration program to begin testing our Permian Basin leasehold. We acquired an additional 55,400 gross (38,900 net) acres in Southeast New Mexico and West Texas. At December 31, 2013, our leasehold position included approximately 70,800 gross (44,800 net) acres in the Permian Basin, primarily in Lea and Eddy Counties, New Mexico and Loving County, Texas in the western Permian Basin. At December 31, 2013, approximately 7,000 gross (4,900 net) of these acres were held by production. We consider the vast majority of this acreage 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, Cisco/Canyon and Glorieta/San Andres formations. We have also acquired approximately 2,000 gross (1,450 net) acres in Howard and Dawson Counties, Texas in the eastern Permian Basin, although we do not expect to drill any wells in the eastern Permian Basin in 2014. In addition, a portion of our leasehold interests in the Permian Basin, including approximately 7,300 gross (450 net) acres in Winkler County, Texas, is no longer considered to be prospective by us, and we plan to allow this acreage to expire without drilling.

At December 31, 2013 and March 13, 2014, we were running one contracted drilling rig in the Permian Basin to further evaluate and delineate our acreage position both geographically and geologically. During 2013, we drilled three wells in the Permian Basin — two in Lea County, New Mexico and one in Loving County, Texas. Our first well, the Ranger 12 State #1 well in Lea County, was a vertical data collection well where we took extensive well log and whole and sidewall core data in an effort to better understand the multiple potential completion targets throughout the vertical section. We were continuing to test multiple potential completion intervals in this well at December 31, 2013. Our second well, the Ranger 33 State Com #1H in Lea County, was a 4,300-ft horizontal lateral drilled and completed in the Second Bone Spring sand with 18 fracturing stages, including 165,000 Bbl of fluid and 7.5 million pounds of sand. This well was placed on production at the end of October 2013 and has continued to exhibit strong performance. In its first three months on production, including the initial cleanup phase, the well produced over 48,000 BOE, including approximately 44,000 Bbl of oil (92% oil), and continued to flow with gas lift assist. Our third well, the Dorothy White #1H in Loving County, Texas, was a 5,000-ft horizontal lateral drilled in the upper portion of the Wolfcamp formation, the Wolfcamp “A”, at approximately 10,700-ft vertical depth. We completed this well in January 2014 with 20 fracturing stages, including 200,000 Bbl of fluid and 9.8 million pounds of sand. The Dorothy White #1H was placed on production in January 2014 and flowed 1,355 BOE per day, including 902 Bbl of oil per day and 2.7 MMcf of natural gas per day (67% oil) at 3,711 pounds per square inch pressure (“psi”) on a 22/64th inch choke during a 24-hour initial potential test.

Because of these encouraging initial results, we plan to run one rig continuously in the western Permian Basin throughout 2014. We have allocated approximately $108.6 million, or about 25% of our 2014 capital expenditure budget of $440.0 million, to our drilling and completion activities in the Permian Basin, as well as for the acquisition of additional leasehold interests in the area. The objective of our 2014 Permian Basin drilling program is to further evaluate and delineate our acreage position in an effort to define an expanded, multi-rig drilling program for 2015 and beyond.

At December 31, 2013, we had identified and engineered 241 gross (177.7 net) locations for potential future drilling on our Permian Basin acreage, primarily in the Wolfcamp or Bone Spring plays, but also including some Avalon shale locations. 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. Because we have just begun the exploration of our properties in the Permian Basin in 2013, our engineered well locations at December 31, 2013 do not yet include all portions of our acreage position. Our identified well locations presume that these properties may be developed on 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. In addition, although our potential future drilling locations presume the drilling of horizontal wells, we also believe that certain portions of our acreage could lend themselves to development with vertical wells. As a result, as we explore and develop our Permian Basin acreage further, we anticipate that we may identify additional locations for future drilling. In addition, although we believe that prospective well locations exist on our acreage for the Delaware formation or other potential completion intervals, we had not included any locations for these intervals in our engineered well locations at December 31, 2013. At December 31, 2013, these potential future drilling locations included only four gross (3.4 net) locations in the Permian Basin to which we have assigned proved undeveloped reserves.

As we continue to explore and develop our leasehold positions in the Permian Basin, we may face challenges with establishing operations in new areas and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to process, transport and market the oil and natural gas we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure on our leases throughout the area. We believe that we have successfully secured the necessary drilling and completion services for our current Permian Basin operations, but industry activity in Southeast New Mexico and West Texas is increasing rapidly, and we may encounter difficulties in securing these services as we move forward with our exploration and development operations in this area in future periods. We believe that maintaining reliable and timely drilling and completion services, reducing drilling and completion costs and securing the necessary pipeline and natural gas processing capabilities will be essential to the successful development and profitability of the Wolfcamp, Bone Spring and other plays in the Permian Basin. See "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."

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 2013, although we did participate in the drilling and completion of 11 gross (0.4 net) non-operated Haynesville shale wells. We do not plan to drill any operated Haynesville shale wells in 2014, but we have budgeted capital expenditures of approximately $12.0 million for our participation in 26 gross (1.5 net) wells that we anticipate may be drilled by other operators on certain of our non-operated properties in 2014, as well as for additional leasehold acquisition opportunities in the Haynesville shale play. Certain of these wells were already in progress at December 31, 2013. During the year ended December 31, 2013, we acquired approximately 1,190 gross (1,190 net) acres in Northwest Louisiana that we consider to be prospective primarily for natural gas production from the core area of the Haynesville shale. This acreage acquisition provides us additional operational flexibility if we resume operated activities in the Haynesville shale play in the future. At December 31, 2013, we held approximately 28,600 gross (25,800 net) acres in Northwest Louisiana and East Texas, including 22,700 gross (15,000 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 13,800 gross (6,900 net) acres that we consider to be in the core area of the Haynesville play.

For 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 leasehold interests in Northwest Louisiana and East Texas. Natural gas production from these properties comprised approximately 58% of our daily natural gas production, but oil production from these properties comprised only about 0.3% of our daily oil production during 2013, as compared to approximately 88% of our daily natural gas production and approximately 1% of our daily oil production during 2012. During the year ended December 31, 2012, approximately 56% of our average daily oil equivalent production, or 5,042 BOE per day, including 31 Bbl of oil per day and 30.1 MMcf of natural gas per day, was attributable to our properties in Northwest Louisiana and East Texas. The decline in oil and particularly natural gas production from these properties over the past year reflects (i) the natural decline in production from these properties, (ii) our decision not to drill any operated Haynesville shale or Cotton Valley wells during 2013 and (iii) the lack of drilling on these properties by our co-working interest owners in 2013.

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. For the year ended December 31, 2012, approximately 76% of our daily natural gas production, or 26.0 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 12%, or 4.1 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties.

At December 31, 2013, approximately 56% of our estimated total proved reserves, or 28.8 million BOE, was attributable to the Haynesville shale with another 3% of our proved reserves, or 1.3 million BOE, attributable to the Cotton Valley and shallower formations underlying this acreage. The unweighted arithmetic average of the first-day-of-the-month natural gas price used to estimate proved natural gas reserves for 2013 increased to $3.670 per MMBtu, as compared to $2.757 per MMBtu for 2012. Primarily as a result of the 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 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale from our estimated total proved reserves at June 30, 2012 because the natural gas price used to estimate natural gas reserves at June 30, 2012 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.

At December 31, 2013, we had identified and engineered 527 gross (114.5 net) locations for potential future drilling in the Haynesville shale play and 71 gross (49.3 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 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 527 gross (114.5 net) locations identified for future drilling on our Haynesville acreage, 452 gross (63.6 net) locations have been identified within the 13,800 gross (6,900 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, 2013, these potential future drilling locations included 125 gross (20.6 net) locations in the Haynesville shale (and no locations in the Cotton Valley) to which we have assigned proved undeveloped reserves.

About one-third of our acreage in the core area of the Haynesville shale play in Northwest Louisiana is operated by a subsidiary of Chesapeake Energy Corporation. During the fourth quarter of 2013, we notified Chesapeake that we would be electing to take in kind the anticipated natural gas production from most of the wells operated by Chesapeake effective January 1, 2014. In addition, in December 2013, we entered into a five-year natural gas gathering agreement effective January 1, 2014 for this natural gas production. This agreement has no firm transportation commitments and no natural gas volume commitments. We believe that taking this natural gas production in kind and transporting through this gathering agreement will improve price realizations and reduce marketing and transportation fees and other costs associated with this natural gas production by an average of approximately $0.70 or more per MMBtu beginning January 1, 2014. 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."

The NYMEX Henry Hub natural gas futures contract price for the earliest delivery date was $4.38 per MMBtu at March 13, 2014. Although we do not have plans to drill any Haynesville or Cotton Valley wells on our operated properties at December 31, 2013, as a result of the recent improvement in natural gas prices, we anticipate that certain of our co-working interest owners may elect to drill additional Haynesville wells in 2014 on properties where they are the operator. As noted above, our 2014 capital expenditure budget includes our participation in 26 gross (1.5 net) non-operated Haynesville wells in 2014, several of which were already in progress at December 31, 2013. Should natural gas prices remain above $4.00 per MMBtu during a significant portion of 2014, however, we believe that we may receive proposals to participate in additional non-operated wells during 2014. Should we elect to participate in these non-operated Haynesville wells, our 2014 capital expenditure budget would most likely be increased accordingly. See "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" and "Risk Factors — We Have Limited Control over Activities on Properties We Do Not Operate."

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, 2013, we had approximately 22,700 gross (15,000 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 13,800 gross (6,900 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 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 not yet 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, 2013.

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 (24.4 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 approximately one-third of our non-operated Haynesville acreage in this area of the play that is operated by a subsidiary of Chesapeake following a sale of a portion of our interest 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/Caspiana properties in Northwest Louisiana, approximately 10,000 gross (9,800 net acres) at December 31, 2013, 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 (49.3 net) additional drilling locations for future Cotton Valley horizontal wells on our Elm Grove/Caspiana properties. We did not drill any of these locations in 2013 and do not plan to drill any of these locations in 2014. 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 further, 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, 2013, we held an estimated 13,800 gross (11,400 net) leasehold and mineral acres by existing production in these areas.

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

At December 31, 2013, we held leasehold interests in approximately 76,500 gross (36,000 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 had no production, no proved reserves and no engineered drilling locations attributable to this acreage at December 31, 2013.

We began drilling the initial test well on this prospect, the Crawford Federal #1 well in Lincoln County, Wyoming, in February 2011. We reached a depth of 8,200 feet, approximately 300 feet above the top of the Meade Peak shale, before having operations suspended for several months due to wildlife restrictions. We resumed operations in September 2011 and completed drilling, well logging and coring operations in November 2011. During 2012, we conducted detailed evaluations of the well logs and conducted special core analysis to better understand the petrophysical characteristics of the Meade Peak shale.

In September 2012, we entered into an agreement with the principal non-operated working interest owner related to the ongoing exploration of the Meade Peak shale, pursuant to which the working interest owner (i) paid us a prospect fee of $1.0 million, (ii) agreed to provide up to a total cost of $3.0 million (carrying our 50% share) for extensions of expiring leases and new leasing in the prospect in which we will have a 50% working interest at no cost to us and (iii) agreed to carry our 50% share of the drilling and completion costs associated with the horizontal lateral up to a total cost for these operations of $5.0 million, with each party paying 50% of all drilling and completion costs in excess of $5.0 million. In return for this consideration, in December 2012, we assigned 50% of our gross and net leasehold interests in the prospect to this working interest owner.

In November 2012, we re-entered the Crawford Federal #1 vertical well and drilled a horizontal lateral from that wellbore into the Meade Peak shale approximately 2,500 feet in length. We completed the lateral with a five-stage fracture treatment in September 2013 and initiated flow back to recover the hydraulic fracture load fluid. Due to weather constraints, we have temporarily suspended our testing program for this well and plan to resume operations in 2014. We plan to evaluate this well with the other working interest owners before making further decisions concerning the future exploration of the Meade Peak shale in this prospect.

OPERATING SUMMARY

The following table sets forth certain unaudited production data for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Unaudited Production Data:			
Net Production Volumes:			
Oil (MBbl)	2,133	1,214	154
Natural gas (Bcf)	12.9	12.5	14.5
Total oil equivalent (MBOE) (1)	4,285	3,294	2,573
Average daily production (BOE/d) (1)	11,740	9,000	7,049
Average Sales Prices:			
Oil, with realized derivatives (per Bbl)	$ 98.67	$103.55	$93.80
Oil, without realized derivatives (per Bbl)	$ 99.79	$101.86	$93.80
Natural gas, with realized derivatives (per Mcf)	$ 4.47	$ 3.55	$ 4.11
Natural gas, without realized derivatives (per Mcf)	$ 4.35	$ 2.59	$ 3.62
Operating Expenses (per BOE):			
Production taxes and marketing	$ 4.89	$ 3.54	$ 2.44
Lease operating	$ 9.04	$ 8.56	$ 2.82
Depletion, depreciation and amortization	$ 22.96	$ 24.43	$12.34
General and administrative	$ 4.85	$ 4.42	$ 5.21

(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, 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.

The following table sets forth information regarding our average net daily production and total production for the year ended December 31, 2012 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]	3,261	4,007	3,928	1,438	43.7%
NW Louisiana/E Texas:					
Haynesville	1	26,007	4,336	1,587	48.2%
Cotton Valley [3]	30	4,051	706	258	7.8%
Area Total	31	30,058	5,042	1,845	56.0%
Permian Basin:					
SE New Mexico, West Texas	25	30	30	11	0.3%
Other:					
Wyoming, Utah, Idaho	—	—	—	—	—
Total	3,317	34,095	9,000	3,294	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 production of approximately 4.3 million BOE for the year ended December 31, 2013 was an increase of 30% from our total production of approximately 3.3 million BOE for the year ended December 31, 2012. This increased production was primarily due to our drilling operations in the Eagle Ford shale. Our average daily production for the year ended December 31, 2013 was 11,740 BOE per day, as compared to 9,000 BOE per day for the year ended December 31, 2012. Our average daily oil production for the year ended December 31, 2013 was 5,843 Bbl of oil per day, an increase of 76% from 3,317 Bbl of oil per day for the year ended December 31, 2012.

PRODUCING WELLS

The following table sets forth information relating to producing wells at December 31, 2013. 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. 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]	69	59.3	4	4.0	73	63.3
NW Louisiana/E Texas:						
Haynesville	—	—	140	13.0	140	13.0
Cotton Valley [2]	2	2.0	98	61.7	100	63.7
Area Total	2	2.0	238	74.7	240	76.7
Permian Basin:						
SE New Mexico, West Texas	12	4.4	1	0.6	13	5.0
Other:						
Wyoming, Utah, Idaho	—	—	—	—	—	—
Total	83	65.7	243	79.3	326	145.0

(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, 2013, 2012 and 2011. 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, 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]		
	2013	2012	2011
Estimated Proved Reserves Data:[2]			
Estimated proved reserves:			
Oil (MBbl)	16,362	10,485	3,794
Natural Gas (Bcf) [3]	212.2	80.0	170.4
Total (MBOE) [4]	51,729	23,819	32,196
Estimated proved developed reserves:			
Oil (MBbl)	8,258	4,764	1,419
Natural Gas (Bcf) [3]	53.5	54.0	56.5
Total (MBOE) [4]	17,168	13,771	10,843
Percent developed	33.2%	57.8%	33.7%
Estimated proved undeveloped reserves:			
Oil (MBbl)	8,104	5,721	2,375
Natural gas (Bcf) [3]	158.7	26.0	113.9
Total (MBOE) [4]	34,561	10,048	21,353
PV-10 [5] (in millions)	$ 655.2	$ 423.2	$ 248.7
Standardized Measure [6] (in millions)	$ 578.7	$ 394.6	$ 215.5

(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, 2013 were $93.42 per Bbl for oil and $3.670 per MMBtu for natural gas, for the 12 months ended December 31, 2012 were $91.21 per Bbl for oil and $2.757 per MMBtu for natural gas, and for the 12 months ended December 31, 2011 were $92.71 per Bbl for oil and $4.118 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, 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, 2013, 2012 and 2011 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, 2013, 2012 and 2011 were, in millions, $76.5, $28.6 and $33.2, respectively.

(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 117% from 23.8 million BOE at December 31, 2012 to 51.7 million BOE at December 31, 2013. Our proved oil reserves grew 56% from approximately 10.5 million Bbl at December 31, 2012 to approximately 16.4 million Bbl at December 31, 2013. This increase is primarily attributable to proved oil reserves added due to our drilling operations in the Eagle Ford shale in South Texas. Our proved natural gas reserves increased 165% from 80.0 Bcf at December 31, 2012 to 212.2 Bcf at December 31, 2013. This increase in our proved natural gas reserves was attributable to our drilling and completion activities in 2013 and to the increase in our proved undeveloped natural gas reserves in 2013 from 26.0 Bcf at December 31, 2012 to 158.7 Bcf at December 31, 2013 due primarily to higher natural gas prices. 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, 2013. The PV-10 of our total proved oil and natural gas reserves increased by 55% from $423.2 million at December 31, 2012 to $655.2 million at December 31, 2013. Our total proved reserves at December 31, 2013 were made up of approximately 32% oil and 68% natural gas, as compared to 44% oil and 56% natural gas at December 31, 2012.

Our proved developed oil and natural gas reserves increased from 13.8 million BOE at December 31, 2012 to 17.2 million BOE at December 31, 2013 due primarily to additions resulting from our drilling operations in the Eagle Ford shale. Our proved developed oil reserves increased from 4.8 million Bbl at December 31, 2012 to 8.3 million Bbl at December 31, 2013 as a result of our drilling operations in the Eagle Ford shale. Our proved developed natural gas reserves decreased slightly from 54.0 Bcf at December 31, 2012 to 53.5 Bcf at December 31, 2013 due primarily to declining natural gas production in the Haynesville shale and Cotton Valley coupled with the fact that we did not drill any operated Haynesville shale or Cotton Valley wells on our operated properties during 2013 and likewise, our co-working interest owners drilled very few Haynesville shale wells on the properties they operate.

The following table summarizes changes in our estimated proved developed reserves at December 31, 2013.

	Proved Developed Reserves (MBOE)[(1)]
As of December 31, 2012	13,771
Extensions and discoveries	3,971
Purchases of minerals-in-place	28
Revisions of prior estimates	(651)
Production	(4,285)
Conversion of proved undeveloped to proved developed	4,334
As of December 31, 2013	17,168

(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 10.0 million BOE at December 31, 2012 to 34.6 million BOE at December 31, 2013. Our proved undeveloped oil reserves increased from 5.7 million Bbl at December 31, 2012 to 8.1 million Bbl at December 31, 2013, primarily as a result of our drilling operations in the Eagle Ford shale. Our proved undeveloped natural gas reserves increased from 26.0 Bcf at December 31, 2012 to 158.7 Bcf at December 31, 2013 due primarily to the previously discussed addition of approximately 134.2 Bcf (22.4 MBOE) 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 is reflected in our estimated total proved reserves at December 31, 2013.

At December 31, 2013, we had no proved reserves in our estimates that remained undeveloped for five years or more following their booking.

The following table summarizes changes in our estimated proved undeveloped reserves at December 31, 2013.

	Proved Undeveloped Reserves (MBOE)(1)
As of December 31, 2012	10,048
Extensions and discoveries	15,260
Purchases of minerals-in-place	—
Revisions of prior estimates	13,587
Conversion of proved undeveloped to proved developed	(4,334)
As of December 31, 2013	34,561

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

The following table sets forth, since 2011, 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)	
2011	—	3.4	573	$ 1,409
2012	283	0.8	415	8,096
2013	2,944	8.3	4,334	115,699
Total	3,227	12.5	5,322	$125,204

(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, 2013:

	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)	15,198	30.1	20,221	$540.4	$477.3
NW Louisiana/E Texas:					
Haynesville	—	172.8	28,797	74.7	66.0
Cotton Valley (6)	36	7.8	1,339	8.2	7.2
Area Total	36	180.6	30,136	82.9	73.2
Permian Basin:					
SE New Mexico, West Texas	1,128	1.5	1,372	31.9	28.2
Other:					
Wyoming, Utah, Idaho	—	—	—	—	—
Total	16,362	212.2	51,729	$655.2	$578.7

(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, 2013 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, 2013 were approximately $76.5 million.

(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 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 36 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.

ACREAGE SUMMARY

The following table sets forth the approximate acreage in which we held a leasehold, mineral or other interest at December 31, 2013.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
South Texas:						
Eagle Ford	22,604	18,206	16,381	8,941	38,985	27,147
NW Louisiana/E Texas:						
Haynesville	18,960	11,238	3,734	3,731	22,694	14,969
Cotton Valley	20,510	18,418	3,916	3,403	24,426	21,821
Area Total (1)	24,215	21,885	4,392	3,876	28,607	25,761
Permian Basin:						
SE New Mexico, West Texas	1,120	897	69,699	43,937	70,819	44,834
Other:						
Wyoming, Utah, Idaho	—	—	76,496	36,004	76,496	36,004
Total	47,939	40,988	166,968	92,758	214,907	133,746

(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, 2013 that will expire prior to December 31, 2015 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 2014		Acres Expiring 2015	
	Gross	Net	Gross	Net
South Texas:				
Eagle Ford	2,879	846	2,343	1,777
NW Louisiana/E Texas:				
Haynesville	11	11	—	—
Cotton Valley	11	11	—	—
Area Total (1)	11	11	—	—
Permian Basin:				
SE New Mexico, West Texas	7,775	706	5,496	2,439
Other:				
Wyoming, Utah, Idaho	—	—	—	—
Total	10,665	1,563	7,839	4,216

(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.

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. 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.

DRILLING RESULTS

The following table summarizes our drilling activity for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	32	20.7	36	17.1	30	0.6
Dry	—	—	—	—	—	—
Exploration Wells						
Productive	14	8.7	22	10.4	30	10.2
Dry (1)	1	0.4	—	—	—	—
Total Wells						
Productive	46	29.4	58	27.5	60	10.8
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, weather conditions, hurricanes in the Gulf Coast region, natural gas storage levels, domestic and foreign governmental regulations, the actions of OPEC, 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 do 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 do 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, 2013, we had five significant purchasers that accounted for approximately 87% of our total oil, natural gas and natural gas liquids revenues. For the years ended December 31, 2012 and 2011, we had three significant purchasers that accounted for approximately 74% and 60%, 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.

About one-third of our acreage in the core area of the Haynesville shale play in Northwest Louisiana is operated by a subsidiary of Chesapeake Energy Corporation. During the fourth quarter of 2013, we notified Chesapeake that we would be electing to take in kind the anticipated natural gas production from most of the wells operated by Chesapeake effective January 1, 2014. In addition, we entered into a five-year natural gas gathering agreement effective January 1, 2014 for this anticipated natural gas production. This agreement has no firm transportation commitments and no natural gas volume commitments. We believe that taking our natural gas production in kind and transporting through this gathering agreement will improve price realizations and reduce marketing and transportation fees and other costs associated with this natural gas production by an average of approximately $0.70 or more per MMBtu. 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."

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 periods, we had an immaterial natural gas deficiency and the counterparty to this agreement has agreed to waive 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 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 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 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 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. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound ("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, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. 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.

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 position, 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 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. We currently own and operate 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.

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 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. 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 2014. Further, the BLM has proposed rules to regulate hydraulic fracturing on federal lands. The EPA has also announced an initiative 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 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 position. 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. In April 2013, we entered into the fifth amendment to our office lease agreement. This amendment increased the square footage of our corporate headquarters to 40,071 square feet effective July 1, 2013. The lease expires on June 30, 2022.

EMPLOYEES

At December 31, 2013, we had 66 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 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. The prices we receive for our production, and the levels of our production, depend on numerous factors. These factors include the following:

- the domestic and foreign supply of oil and natural gas;
- the domestic and foreign demand for oil and natural gas;
- the prices and availability of competitors' supplies of 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 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, including the Middle East and South America;
- 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.

Approximately 50% of our production during the year ended December 31, 2013 and 68% of our proved reserves at December 31, 2013 were attributable to natural gas. In addition, three of our significant assets or prospects — the Haynesville shale, Cotton Valley and Meade Peak shale — currently produce or are expected to produce predominantly natural gas. As a result, they are sensitive to fluctuations in natural gas prices.

During 2013, natural gas prices began the year with a low of approximately $3.11 per MMBtu in early January, climbed to approximately $4.41 per MMBtu in late April and fell back to approximately $3.23 per MMBtu in early August before reaching a 2013 high of approximately $4.46 per MMBtu in late December, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. Natural gas prices climbed to above $6.00 per MMBtu in early 2014 and settled at $4.38 per MMBtu at March 13, 2014, based upon the NYMEX Henry Hub natural gas futures contract for the earliest delivery date. Although we do not expect to drill any operated natural gas wells in the Haynesville shale or Cotton Valley in 2014, given the recent improvement in natural gas prices, we anticipate that certain of our co-working interest owners may drill natural gas wells, and in particular Haynesville shale wells, on properties they operate. We expect to be offered the opportunity to participate, and most likely will participate, in these non-operated natural gas wells.

In 2011, we began to focus on increasing our oil and liquids production. Specifically, our drilling opportunities in the Eagle Ford shale play in South Texas and in the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas focus on oil and liquids. Approximately 50% of our production during the year ended December 31, 2013 and 32% of our proved reserves at December 31, 2013 were attributable to oil. We currently intend to allocate approximately 97% of our 2014 capital expenditure budget to opportunities prospective for oil and liquids production, including primarily the Eagle Ford shale and the Wolfcamp and Bone Spring plays. These opportunities are sensitive to changes in oil prices. For the year ended December 31, 2013, oil prices ranged from a low of approximately $86.68 per Bbl in mid-April to a high of approximately $110.53 per Bbl in early September, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date.

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 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.

Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of 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 the drilling, completing and operating processes. Before a well is spud, we may incur significant geological and geophysical (seismic) costs, which are incurred whether 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 predict 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;
- 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.

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 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.

Although we currently have no plans to do so, 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, 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, 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.

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 an acquisition, 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.

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

At March 13, 2014, we had available borrowings of approximately $134.7 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 acquired 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 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;
- impairing 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.

We May Have Accidents, Equipment Failures or Mechanical Problems While Drilling or Completing Wells or in Production Activities, Which Could Adversely Affect Our Business.

While we are drilling and completing oil or natural gas wells or involved in production activities, we may have accidents or experience equipment failures or mechanical problems in a well that cause us to be unable to drill and complete the well or to continue to produce the well according to our plans. We may also damage a potentially hydrocarbon-bearing formation during drilling and completion operations. Such incidents may result in a reduction of our production and reserves from, or abandonment of, the well, and the costs associated with remedying such accidents 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 Small Number of Properties, Problems in Production and Markets Relating to Any Property 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 South Texas and in Northwest Louisiana and East Texas. For the year ended December 31, 2013, approximately 70% of our oil and natural gas production, including approximately 98% of our average daily oil production, was attributable to our properties in South Texas. At December 31, 2013, approximately 82% of the PV-10 of our proved reserves and approximately 93% of our total proved oil reserves were attributable to our properties in South Texas, primarily in the Eagle Ford shale. We expect that most of our operations in the near future will be primarily in South Texas. In addition, we expect to direct approximately 25% of our 2014 capital expenditure budget to further evaluating our acreage position in the Permian Basin in Southeast New Mexico and West 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 exploration and drilling, 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 quarter of 2013, 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. Although we did not experience any material delays or other issues as a result of inclement weather in this area, 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. Such delays or interruptions 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 vendors to the industry. 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 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. 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 Eagle Ford shale and the Permian Basin, 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 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.

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. We generally base the estimated discounted future net cash flows from proved reserves 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 68% of Our Total Proved Reserves at December 31, 2013 Consisted of Undeveloped and Developed Non-Producing Reserves, and Those Reserves May Not Ultimately Be Developed or Produced.

At December 31, 2013, approximately 67% of our total proved reserves were undeveloped and approximately 1% 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 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 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, 2013, we had leasehold interests in approximately 5,800 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, 2015. 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.

We May Not Increase Our Acreage Positions in Areas with Exposure to Oil, Condensate and Natural Gas Liquids.

If we are unable to locate or consummate acquisition opportunities and increase our acreage positions in the Eagle Ford shale in South Texas, the Permian Basin in Southeast New Mexico and West Texas or other areas with similar exposure to oil, condensate and natural gas liquids, we may not realize our growth strategy in oil and liquids-rich plays. The inability to realize our growth strategy and increase our acreage positions in these areas could adversely affect our business, financial condition, results of operations and cash flows.

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. 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.

We Currently Own Only a Limited Amount of Seismic and Other Geological Data and May Have Difficulty Obtaining Additional Data at a Reasonable Cost, Which Could Adversely Affect Our Results of Operations and Cash Flows.

We currently own only a limited amount of seismic and other geological data to assist us in exploration and development activities. We intend to obtain access to additional data in our areas of interest through licensing arrangements with companies that own or have access to that data or by paying to obtain that data directly. Seismic and geological data can be expensive to license or obtain. We may not be able to license or obtain such data at an acceptable cost, which could negatively 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.

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. 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 2014. 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 essentially all 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. 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.

The Third Parties on Whom We Rely for 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 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 third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third party 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 third 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 a subsidiary of Chesapeake Energy Corporation 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 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 effectively could reduce our focus on subsequent acquisitions and current operations, and could negatively impact our results of operations and growth potential. 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 position, 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 negotiating 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 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 in 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. 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. A write-down does not affect net cash flows from operating activities, 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 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.

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 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.

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 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 2014.

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 announced an initiative 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, which could include a moratorium on drilling and effectively prohibit further production of oil and natural gas through the use of hydraulic fracturing or similar operations. Texas and Wyoming have adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process. This legislation and any implementing regulations could increase our costs of compliance and doing business.

The adoption of new laws or regulations imposing reporting obligations on, or otherwise limiting, 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 require owners/operators to reduce 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. 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.

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 we expand our activities, including our planned increase in oil exploration, development and production, and increase 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 of the Board 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.

RISKS RELATING TO OUR COMMON 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 2013, our stock price fluctuated between a high of $24.10 and a low of $7.58. 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 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;

- 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.

The Requirements of Being a Public Company, Including Compliance with the Reporting Requirements of the Securities Exchange Act of 1934, as Amended, and the Requirements of the Sarbanes-Oxley Act of 2002, Have Increased Our Costs and Occupy a Significant Amount of Management's Time.

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.

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.

Until February 2012, we were a private company and maintained internal controls and procedures in accordance with being a private company. We maintained limited accounting personnel to perform our accounting processes and limited supervisory resources with which to address our internal control over financial reporting. In connection with our audits for the years ended December 31, 2011 and 2010, our independent registered public accountants identified and communicated material weaknesses. There were no material weaknesses identified in connection with our audits for the years ended December 31, 2013 and 2012.

A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual and interim financial statements will not be prevented or detected and corrected on a timely basis.

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

The Trading Volume of Our Common Stock Has Been Low, and the Sale of a Substantial Number of Shares in the Public Market Could Depress the Price of Our Common Stock.

Our common stock is listed on the NYSE and has had a lower average daily trading volume relative to many other stocks. Thinly traded stock can be more volatile than stock trading in an active public market, which can lead to significant price swings even when a relatively small number of shares are being traded and can limit an investor's ability to quickly sell blocks of stock.

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, 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 additional shares of common stock, such as in our September 2013 equity offering, or securities convertible into common stock. 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;
- 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 Approximately 10% of Our Common Stock, 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.

Our directors and executive officers beneficially own approximately 10% of our outstanding common stock. 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. Issuances of 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.

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.

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 March 13, 2014, we had 65,744,878 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:

	2013		2012	
	High	Low	High	Low
First Quarter	$ 9.00	$ 7.58	$12.33	$10.85
Second Quarter	$12.48	$ 8.25	$12.09	$ 8.63
Third Quarter	$17.89	$11.49	$11.53	$ 9.41
Fourth Quarter	$24.10	$15.62	$10.50	$ 7.70

On March 13, 2014, the last reported sales price of our common stock on the NYSE was $22.06 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.

Prior to the consummation of our initial public offering on February 7, 2012, the holders of our Class B common stock were entitled to be paid cumulative dividends at a per share rate of $0.26-2/3 annually out of funds legally available for the payment of dividends. These dividends accrued and were payable quarterly at the rate of $0.06-2/3 per share of Class B common stock outstanding. Upon the automatic conversion of the outstanding shares of Class B common stock at the closing of our initial public offering, the right of the holders of Class B common stock to dividends was terminated and such holders were paid approximately $28,000 during the first quarter of 2012 for all accrued but unpaid dividends existing at the time of such conversion.

EQUITY COMPENSATION PLAN INFORMATION

The following table presents the securities authorized for issuance under our equity compensation plans as of December 31, 2013.

	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)	1,613,695	$9.32	1,778,715
Equity compensation plans not approved by security holders	—	—	—
Total	1,613,695	$9.32	1,778,715

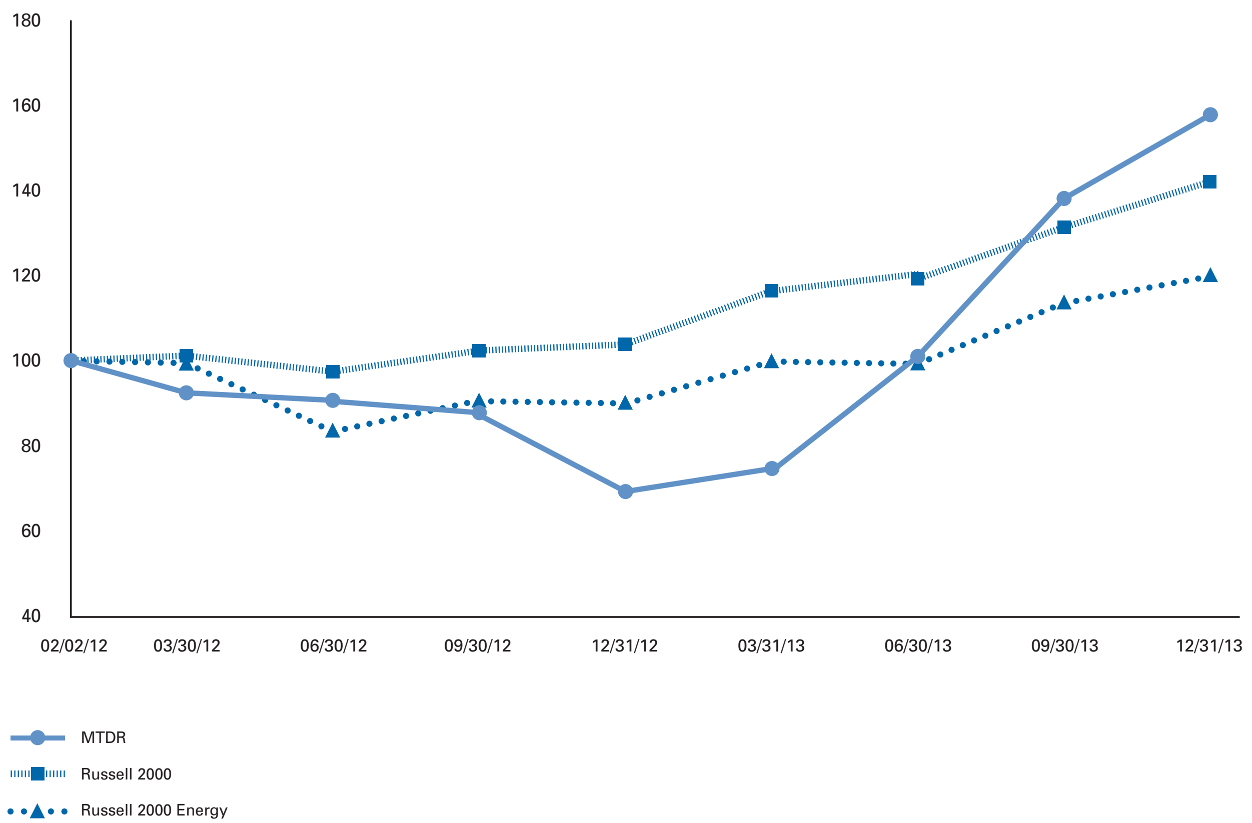
(1) Our Board of Directors has determined not to make any additional grants of awards under the Matador Resources Company 2003 Stock and Incentive Plan.

(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, 2013, 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 of 1933 or the Securities Exchange Act of 1934, as amended (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.

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG MATADOR RESOURCES COMPANY, THE RUSSELL 2000 INDEX AND THE RUSSELL 2000 ENERGY INDEX



REPURCHASE OF EQUITY BY THE COMPANY OR AFFILIATES

None.

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 position or cash flows.

The following selected financial information is summarized from our results of operations for the five-year period ended December 31, 2013 and selected consolidated balance sheet data at December 31, 2013, 2012, 2011, 2010 and 2009 and should be read in conjunction with the consolidated financial statements for the years ended December 31, 2013, 2012 and 2011 included herewith.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
(In thousands, except per share data)					
Statement of operations data:					
Revenues:					
Oil and natural gas revenues	$ 269,030	$ 155,998	$ 67,000	$ 34,042	$ 19,039
Realized (loss) gain on derivatives	(909)	13,960	7,106	5,299	7,625
Unrealized (loss) gain on derivatives	(7,232)	(4,802)	5,138	3,139	(2,375)
Total revenues	260,889	165,156	79,244	42,480	24,289
Expenses:					
Production taxes and marketing	20,973	11,672	6,278	1,982	1,077
Lease operating	38,720	28,184	7,244	5,284	4,725
Depletion, depreciation and amortization	98,395	80,454	31,754	15,596	10,743
Accretion of asset retirement obligations	348	256	209	155	137
Full-cost ceiling impairment	21,229	63,475	35,673	—	25,244
General and administrative	20,779	14,543	13,394	9,702	7,115
Total expenses	200,444	198,584	94,552	32,719	49,041
Operating income (loss)	60,445	(33,428)	(15,308)	9,761	(24,752)
Other income (expense):					
Net loss on asset sales and inventory impairment	(192)	(485)	(154)	(224)	(379)
Interest expense	(5,687)	(1,002)	(683)	(3)	—
Interest and other income	225	224	315	364	781
Total other (expense) income	(5,654)	(1,263)	(522)	137	402
Net income (loss)	$ 45,094	$ (33,261)	$ (10,309)	$ 6,377	$ (14,425)
Earnings (loss) per common share					
Basic					
Class A	$ 0.77	$ (0.62)	$ (0.25)	$ 0.15	$ (0.37)
Class B	$ —	$ (0.35)	$ 0.02	$ 0.42	$ (0.10)
Diluted					
Class A	$ 0.77	$ (0.62)	$ (0.25)	$ 0.15	$ (0.37)
Class B	$ —	$ (0.35)	$ 0.02	$ 0.42	$ (0.10)
Class B dividend declared, per share	$ —	$ 0.27	$ 0.27	$ 0.27	$ 0.27

	At December 31,				
	2013	2012	2011	2010	2009
(In thousands)					
Balance sheet data:					
Cash and cash equivalents	$ 6,287	$ 2,095	$ 10,284	$ 21,060	$104,230
Certificates of deposit	—	230	1,335	2,349	15,675
Net property and equipment	845,877	591,090	399,865	303,880	142,078
Total assets	890,330	632,029	439,469	346,382	277,400
Current liabilities	100,327	96,492	74,576	30,097	8,868
Long-term liabilities	221,079	156,433	93,378	34,408	4,211
Total shareholders' equity	$568,924	$379,104	$271,515	$281,877	$264,321

	Year Ended December 31,				
	2013	2012	2011	2010	2009
(In thousands)					
Other financial data:					
Net cash provided by operating activities	$ 179,470	$ 124,228	$ 61,868	$ 27,273	$ 1,791
Net cash used in investing activities	(366,939)	(306,916)	(160,088)	(147,334)	(49,415)
Oil and natural gas properties capital expenditures	(363,192)	(300,689)	(156,431)	(159,050)	(54,244)
Expenditures for other property and equipment	(3,977)	(7,332)	(4,671)	(1,610)	(307)
Net cash provided by financing activities	191,661	174,499	87,444	36,891	1,086
Adjusted EBITDA (1)	$ 191,771	$ 115,923	$ 49,911	$ 23,635	$ 15,184

(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.

(In thousands)	Year Ended December 31, 2013	2012	2011	2010	2009
Unaudited Adjusted EBITDA Reconciliation to Net Income (Loss):					
Net income (loss)	$ 45,094	$ (33,261)	$(10,309)	$ 6,377	$(14,425)
Interest expense	5,687	1,002	683	3	—
Total income tax provision (benefit)	9,697	(1,430)	(5,521)	3,521	(9,925)
Depletion, depreciation and amortization	98,395	80,454	31,754	15,596	10,743
Accretion of asset retirement obligations	348	256	209	155	137
Full-cost ceiling impairment	21,229	63,475	35,673	—	25,244
Unrealized loss (gain) on derivatives	7,232	4,802	(5,138)	(3,139)	2,375
Stock-based compensation expense	3,897	140	2,406	898	656
Net loss on asset sales and inventory impairment	192	485	154	224	379
Adjusted EBITDA	$191,771	$115,923	$ 49,911	$23,635	$ 15,184

(In thousands)	Year Ended December 31, 2013	2012	2011	2010	2009
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:					
Net cash provided by operating activities	$179,470	$124,228	$ 61,868	$27,273	$ 1,791
Net change in operating assets and liabilities	6,210	(9,307)	(12,594)	(2,230)	15,717
Interest expense	5,687	1,002	683	3	—
Current income tax provision (benefit)	404	—	(46)	(1,411)	(2,324)
Adjusted EBITDA	$191,771	$115,923	$ 49,911	$23,635	$ 15,184

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 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. In addition, we have a large exploratory leasehold position in Southwest Wyoming and adjacent areas of Utah and Idaho where we are testing the Meade Peak shale.

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.

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 are using the net proceeds from this offering primarily to fund a portion of our capital expenditures, including for the addition of the third rig to our drilling program. We are also using 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 may be reborrowed in accordance with the terms of that facility for, among other items, the uses contemplated above.

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 factor for us. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, 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.

In 2013, almost all of our operated drilling activities and approximately 70% of our total capital expenditures of $373.5 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 increased our leasehold position significantly in the Permian Basin in Southeast New Mexico and West Texas during 2013. At December 31, 2013, we held approximately 70,800 gross (44,800 net) acres in the Permian Basin, as compared to approximately 15,900 gross (7,600 net) acres at December 31, 2012. We also initiated our exploratory drilling activities in the Permian Basin during 2013 to begin the evaluation and delineation of our acreage position. Approximately 27% of our 2013 capital expenditures were directed to our three-well exploration program testing portions of our leasehold position in the Permian Basin and to the acquisition of additional interests prospective for the Wolfcamp, Bone Spring and other oil and liquids-rich plays in the Permian Basin. For the year ended December 31, 2013, approximately 50% of our total production by volume (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) and almost 80% of our total oil and natural gas revenues were attributable to oil production, primarily in the Eagle Ford shale.

During the first quarter of 2013, we had two contracted drilling rigs operating full-time in South Texas and all of our operated drilling and completion activities were focused on the Eagle Ford shale. In late April 2013, we moved one of these contracted drilling rigs to Southeast New Mexico to begin a three-well exploration program testing portions of our leasehold acreage in the Permian Basin, while the second contracted drilling rig continued to operate in the Eagle Ford shale. In mid-August 2013, we added a third contracted drilling rig to our drilling program and returned to operating two contracted drilling rigs in the Eagle Ford shale. We expect to operate two contracted drilling rigs in the Eagle Ford shale and one rig in the Permian Basin throughout 2014. At March 13, 2014, our two Eagle Ford rigs were operating in La Salle and Wilson Counties, Texas, respectively, and our Permian Basin rig was operating in Lea County, New Mexico.

During the year ended December 31, 2013, we completed and began producing oil and natural gas from 25 gross (25.0 net) operated and seven gross (2.6 net) non-operated Eagle Ford shale wells. We also participated in 11 gross (0.4 net) non-operated Haynesville shale wells in Northwest Louisiana and one non-operated test of the Buda formation in South Texas (approximately 21% working interest). During 2013, we also initiated an exploration program testing portions of our growing leasehold position in the Permian Basin. We drilled three wells on this acreage in 2013, including one vertical data well, where we collected extensive well log and whole core data, and one horizontal well testing the Second Bone Spring formation, both in Lea County, New Mexico. We began producing oil and natural gas from the Second Bone Spring horizontal well in late October 2013. We also drilled a horizontal well testing the Wolfcamp "A" formation in Loving County, Texas. This well was completed and began producing oil and natural gas in January 2014.

Our average daily oil equivalent production for the year ended December 31, 2013 was the best in Matador's history at 11,740 BOE per day, including 5,843 Bbl of oil per day and 35.4 MMcf of natural gas per day, an increase of 30% as compared to 9,000 BOE per day, including 3,317 Bbl of oil per day and 34.1 MMcf of natural gas per day, for the year ended December 31, 2012. Our average daily oil production of 5,843 Bbl of oil per day was an increase of 76%, as compared to an average daily oil production of 3,317 Bbl of oil per day during the year ended December 31, 2012. This increase in oil production was a direct result of our drilling operations in the Eagle Ford shale. Oil production comprised 50% 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, 2013, as compared to 37% for the year ended December 31, 2012 and only 6% for the year ended December 31, 2011.

Our oil and natural gas revenues and Adjusted EBITDA for the year ended December 31, 2013 were also the highest achieved for any year in our history. For the year ended December 31, 2013, our oil and natural gas revenues were $269.0 million, an increase of 72% from oil and natural gas revenues of $156.0 million for the year ended December 31, 2012. Our oil revenues and natural gas revenues increased 72% and 74% to approximately $212.8 million and $56.2 million, respectively, for the year ended December 31, 2013, as compared to $123.7 million and $32.3 million, respectively, for the year ended December 31, 2012. Adjusted EBITDA for the year ended December 31, 2013 was $191.8 million, an increase of 65% from an Adjusted EBITDA of $115.9 million reported for the year ended December 31, 2012. 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, 2013, our estimated total 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. At December 31, 2012, our estimated proved oil and natural gas reserves were 23.8 million BOE, including 10.5 million Bbl of oil and 80.0 Bcf of natural gas, with a PV-10 of $423.2 million and a Standardized Measure of $394.6 million. Our estimated proved oil reserves of 16.4 million Bbl at December 31, 2013 increased 56%, as compared to 10.5 million Bbl at December 31, 2012. 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."

The unweighted arithmetic average of the first-day-of-the-month natural gas price used to estimate natural gas reserves at December 31, 2013 increased to $3.670 per MMBtu, as compared to $2.757 per MMBtu for 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 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves from our estimated total proved reserves at June 30, 2012 because the natural gas price used to estimate natural gas reserves at June 30, 2012 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.

As we continue to explore and develop our leasehold positions in the Eagle Ford shale and as we continue to explore and develop our leasehold positions in the Wolfcamp and Bone Spring plays in the Permian Basin, we may face various challenges in establishing operations in new areas, including securing the necessary services to drill and complete wells and securing the necessary facilities to gather, process, transport and market the oil and natural gas that we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure on our leases throughout the area. We believe that we have successfully secured the necessary drilling and completion services for our current Eagle Ford operations. We did not experience difficulties in securing completion, and in particular hydraulic fracturing, services for our newly drilled wells during the years ended December 31, 2013 or December 31, 2012, although we experienced these problems at various times during 2011 in South Texas and may have such difficulties again in the future. We believe that maintaining reliable and timely drilling and completion services and reducing drilling and completion costs will be essential to the successful development and profitability of the Eagle Ford shale play, as well as the Wolfcamp and Bone Spring plays in the Permian Basin. See "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."

In the past, we have experienced pipeline and natural gas processing interruptions and capacity and infrastructure constraints associated with natural gas production, which have, among other things, required us to flare natural gas occasionally. To alleviate a portion of such interruptions and processing capacity constraints, 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 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. No assurance can be made that this agreement will alleviate these issues completely, and if we were required to shut in or flare 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. We may experience similar interruptions and processing capacity constraints as we explore and develop our leasehold position in the Permian Basin in 2014, although we experienced no material issues in 2013. 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."

About one-third of our acreage in the core area of the Haynesville shale play in Northwest Louisiana is operated by a subsidiary of Chesapeake Energy Corporation. During the fourth quarter of 2013, we notified Chesapeake that we would be electing to take in kind the anticipated natural gas production from most of the wells operated by Chesapeake effective January 1, 2014. In addition, in December 2013, we entered into a five-year natural gas gathering agreement effective January 1, 2014 for this anticipated natural gas production. This agreement has no firm transportation commitments and no natural gas volume commitments. We believe that taking our natural gas production in kind and transporting through this gathering agreement will improve our natural gas price realizations and reduce marketing and transportation fees and other costs associated with this natural gas production by an average of approximately $0.70 or more per MMBtu. 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."

Our estimated capital expenditure budget for 2014 is $440 million, and 97% is expected to be directed towards oil and liquids-rich opportunities. Development of our Eagle Ford shale assets will continue to be the primary driver of our growth in 2014 and approximately $318 million, or 72%, of our estimated 2014 capital expenditures will be directed to increasing our oil production and oil reserves in South Texas. Approximately $109 million, or 25%, of our 2014 estimated capital expenditures will be allocated to further exploration of our growing leasehold position in the Permian Basin. The objective of our Permian Basin drilling program in 2014 is to further evaluate and delineate our acreage, both geographically and geologically, in order to better define an expanded development plan for this acreage in 2015 and beyond. Although we do not plan to drill any operated Haynesville shale natural gas wells during 2014, approximately $12 million, or 3%, of our 2014 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 2014 drilling program through operating cash flows and borrowings under our Credit Agreement. We anticipate that our borrowing capacity will continue to increase during 2014 as a result of the addition of proved reserves resulting from our drilling activities, particularly in the Eagle Ford shale and the Permian Basin. While we have budgeted approximately $440 million for 2014, 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.

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,		
	2013	2012	2011
Operating Data:			
Revenues (in thousands): (1)			
Oil	$212,833	$123,654	$14,457
Natural gas	56,197	32,344	52,543
Total oil and natural gas revenues	269,030	155,998	67,000
Realized (loss) gain on derivatives	(909)	13,960	7,106
Unrealized (loss) gain on derivatives	(7,232)	(4,802)	5,138
Total revenues	$260,889	$165,156	$79,244
Net Production Volumes: (1)			
Oil (MBbl)	2,133	1,214	154
Natural gas (Bcf)	12.9	12.5	14.5
Total oil equivalent (MBOE) (2)	4,285	3,294	2,573
Average daily production (BOE/d) (2)	11,740	9,000	7,049
Average Sales Prices:			
Oil, with realized derivatives (per Bbl)	$ 98.67	$ 103.55	$ 93.80
Oil, without realized derivatives (per Bbl)	$ 99.79	$ 101.86	$ 93.80
Natural gas, with realized derivatives (per Mcf)	$ 4.47	$ 3.55	$ 4.11
Natural gas, without realized derivatives (per Mcf)	$ 4.35	$ 2.59	$ 3.62

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

Oil and natural gas revenues. Our oil and natural gas revenues increased $113.0 million to $269.0 million, or an increase of 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 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. Our oil revenues increased $89.2 million, 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, 2013 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, as compared to $32.3 million for the year ended December 31, 2012, 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 for 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 approximately $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 price of some of our costless collar contracts and the fixed price 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 derivatives 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 derivatives contracts decreased to approximately $(2.8) million, from $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 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.

Year Ended December 31, 2012 as Compared to Year Ended December 31, 2011

Oil and natural gas revenues. Our oil and natural gas revenues increased by $89.0 million to $156.0 million, or an increase of about 133%, for the year ended December 31, 2012, as compared to the year ended December 31, 2011. This increase in oil and natural gas revenues reflects an increase in our oil revenues of $109.2 million and a decrease in our natural gas revenues of $20.2 million for the year ended December 31, 2012, as compared to the year ended December 31, 2011. Our oil revenues increased over eight-fold to $123.7 million for the year ended December 31, 2012, as compared to $14.5 million for the year ended December 31, 2011. Our oil production also increased almost eight-fold to just over 1.2 million Bbl of oil, or about 3,317 Bbl of oil per day, from approximately 154,000 Bbl of oil, or about 422 Bbl of oil per day, during the comparable periods due to our drilling operations in the Eagle Ford shale. A portion of this increase in oil revenue also reflects a higher weighted average oil price of $101.86 per Bbl realized during the year ended December 31, 2012, as compared to a weighted average oil price of $93.80 per Bbl realized during the year ended December 31, 2011. The decrease in our natural gas revenues reflects a decline in our natural gas production by about 14% to approximately 12.5 Bcf for the year ended December 31, 2012, as compared to approximately 14.5 Bcf for the year ended December 31, 2011. This decline in natural gas production was due to several factors, including (i) the natural decline in natural gas production primarily from our existing Haynesville shale and Cotton Valley wells in Northwest Louisiana and East Texas, coupled with our decision not to drill any operated Haynesville shale or Cotton Valley wells in 2012, (ii) the voluntary curtailment by the operators of natural gas production from some of our non-operated Haynesville shale wells in Northwest Louisiana at various times during 2012 and (iii) delays in natural gas production from our newly completed Eagle Ford shale wells in South Texas as a result of natural gas pipeline and production facility constraints. This decrease in natural gas revenues also results from a significantly lower weighted average natural gas price of $2.59 per Mcf realized during the year ended December 31, 2012, as compared to a weighted average natural gas price of $3.62 per Mcf realized during the year ended December 31, 2011.

Realized gain on derivatives. Our realized gain on derivatives increased by approximately $6.9 million to $14.0 million for the year ended December 31, 2012 from $7.1 million for the year ended December 31, 2011. For the year ended December 31, 2012, we realized a gain of approximately $11.9 million on our open natural gas derivative contracts and a gain of approximately $2.0 million on our open oil derivative contracts. As a result of declining natural gas prices between the comparable periods, we realized 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, as compared to an average gain of $1.03 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2011. Our total natural gas volumes hedged for the year ended December 31, 2012 were also approximately 19% higher than the total natural gas volumes hedged for the year ended December 31, 2011. We realized an average gain of $1.74 per Bbl hedged on all of our open oil contracts during the year ended December 31, 2012. We had no open oil or NGL derivative contracts during the year ended December 31, 2011.

Unrealized gain (loss) on derivatives. Our unrealized loss on derivatives was approximately $4.8 million for the year ended December 31, 2012, as compared to an unrealized gain of $5.1 million for the year ended December 31, 2011. During the period from December 31, 2011 to December 31, 2012, the net fair value of our open oil, natural gas and natural gas liquids derivative contracts decreased from approximately $9.3 million to approximately $4.5 million, resulting in an unrealized loss on derivatives of approximately $4.8 million for the year ended December 31, 2012. During the year ended December 31, 2012, the net fair value of our open natural gas costless collar contracts decreased by $8.7 million due primarily to the gains realized on these contracts during 2012. The net fair value of our open oil derivative contracts increased $3.7 million during the year ended December 31, 2012 as a result of a decrease in oil futures prices at December 31, 2012 compared to December 31, 2011 and also as a result of two additional oil derivatives contracts we entered into during 2012. During the year ended December 31, 2012, we also entered into various NGL swap contracts which had a net fair value of approximately $0.2 million at December 31, 2012. We had no open NGL swap contracts during the year ended December 31, 2011.

EXPENSES

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

	Year Ended December 31,		
	2013	2012	2011
(In thousands, except expenses per BOE)			
Expenses:			
Production taxes and marketing	$ 20,973	$ 11,672	$ 6,278
Lease operating	38,720	28,184	7,244
Depletion, depreciation and amortization	98,395	80,454	31,754
Accretion of asset retirement obligations	348	256	209
Full-cost ceiling impairment	21,229	63,475	35,673
General and administrative	20,779	14,543	13,394
Total expenses	200,444	198,584	94,552
Operating income (loss)	60,445	(33,428)	(15,308)
Other (expense) income:			
Net loss on asset sales and inventory impairment	(192)	(485)	(154)
Interest expense	(5,687)	(1,002)	(683)
Interest and other income	225	224	315
Total other expense	(5,654)	(1,263)	(522)
Income (loss) before income taxes	54,791	(34,691)	(15,830)
Total income tax provision (benefit)	9,697	(1,430)	(5,521)
Net income (loss)	$ 45,094	$ (33,261)	$(10,309)
Expenses per BOE:			
Production taxes and marketing	$ 4.89	$ 3.54	$ 2.44
Lease operating	$ 9.04	$ 8.56	$ 2.82
Depletion, depreciation and amortization	$ 22.96	$ 24.43	$ 12.34
General and administrative	$ 4.85	$ 4.42	$ 5.21

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 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 by 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 production 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, an increase of 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, 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 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 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 provision 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 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.

Year Ended December 31, 2012 as Compared to Year Ended December 31, 2011

Production taxes and marketing. Our production taxes and marketing expenses increased by $5.4 million to $11.7 million, or an increase of approximately 86%, for the year ended December 31, 2012, as compared to the year ended December 31, 2011. The increase in our production taxes and marketing expenses primarily reflects the increase in our total oil and natural gas revenues by 133% for the year ended December 31, 2012, as compared to the year ended December 31, 2011. The majority of this increase was attributable to increased production taxes associated with the large increase in our oil production during 2012 resulting from our drilling operations in the Eagle Ford shale in South Texas. Our total production was comprised of approximately 37% oil and 63% natural gas during the year ended December 31, 2012, as compared to approximately 6% oil and 94% natural gas during the year ended December 31, 2011. On a unit-of-production basis, our production taxes and marketing expenses increased by 45% to $3.54 per BOE for the year ended December 31, 2012, as compared to $2.44 per BOE for the year ended December 31, 2011.

Lease operating expenses. Our lease operating expenses increased by $20.9 million to $28.2 million, or an increase of about 289%, for the year ended December 31, 2012, as compared to the year ended December 31, 2011. Our total oil and natural gas production increased by about 28% to approximately 3.3 million BOE for the year ended December 31, 2012 from approximately 2.6 million BOE for the year ended December 31, 2011, but our oil production increased almost eight-fold to just over 1.2 million Bbl from approximately 154,000 Bbl during the respective period. The increase in lease operating expenses was primarily attributable to the increased costs associated with operating oil production resulting from drilling operations in the Eagle Ford shale in 2012, as compared to the lower lease operating expenses associated with operating primarily dry natural gas production from the Haynesville and Cotton Valley in 2011. In addition, oil production comprised 37% of our total production during the year ended December 31, 2012, as compared to only 6% for the year ended December 31, 2011, resulting in higher overall lease operating expenses during the year ended December 31, 2012. During the year ended December 31, 2012, we completed and initiated oil and natural gas production from 28 gross (24.5 net) wells in the Eagle Ford shale (plus two gross (2.0 net) Austin Chalk/"Chalkleford" wells), most of which were on properties where new production facilities were being installed or natural gas pipelines were awaiting completion. While these new facilities were being installed and tested, much of the oil and natural gas was produced through rental equipment monitored by 24-hour contract personnel, resulting in higher operating costs from these properties during the year ended December 31, 2012. Approximately one-third of our total lease operating expenses in 2012 were attributable to these extended flowback operations. Our lease operating expenses per unit of production increased 204% to $8.56 per BOE for the year ended December 31, 2012, as compared to $2.82 per BOE for the year ended December 31, 2011.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $48.7 million to $80.5 million, or an increase of about 153%, for the year ended December 31, 2012, as compared to the year ended December 31, 2011. On a unit-of-production basis, our depletion, depreciation and amortization expenses increased to $24.43 per BOE for the year ended December 31, 2012, as compared to $12.34 per BOE for the year ended December 31, 2011. This increase in our depletion, depreciation and amortization expenses was primarily attributable to the decrease in our total proved oil and natural gas reserves to 23.8 million BOE at December 31, 2012, as compared to 32.2 million BOE at December 31, 2011. 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 in Northwest Louisiana from our total proved reserves at June 30, 2012, and these proved undeveloped reserves were likewise not included in our total proved reserves at December 31, 2012. The increase in depletion, depreciation and amortization expenses was also partially attributable to the increase of approximately 28% in our oil and natural gas production to approximately 3.3 million BOE for the year ended December 31, 2012, as compared to approximately 2.6 million BOE for the year ended December 31, 2011, as well as to the higher drilling and completion costs on a per BOE basis associated with oil reserves added in the Eagle Ford shale in South Texas as compared with our Haynesville shale natural gas assets in Northwest Louisiana.

Accretion of asset retirement obligations. Our accretion of asset retirement obligations expenses increased by approximately $47,000 to $256,000, or an increase of about 23%, for the year ended December 31, 2012, as compared to the year ended December 31, 2011. The increase in the accretion of our asset retirement obligations was due primarily to the addition of new wells through our drilling of operated wells and our participation in the drilling of non-operated wells, although, on the whole, this item is an insignificant component of our overall expenses.

Full-cost ceiling impairment. 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. During the first quarter of 2011, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling by $23.0 million. As a result, we recorded an impairment charge of $35.7 million to the net capitalized costs of our oil and natural gas properties and a deferred income tax credit of $12.7 million, which is reflected in our operating expenses for the year ended December 31, 2011.

General and administrative. Our general and administrative expenses increased by $1.1 million to $14.5 million, or an increase of about 9%, for the year ended December 31, 2012, as compared to the year ended December 31, 2011. Our general and administrative expenses decreased by 15% on a unit-of-production basis to $4.42 per BOE for the year ended December 31, 2012, as compared to $5.21 per BOE for the year ended December 31, 2011. The increase in our general and administrative expenses was attributable to increased compensation, accounting, legal and other administrative expenses, most of which was associated with becoming a public company in February 2012, partially offset by a net decrease in non-cash stock-based compensation expense of $2.3 million for the year ended December 31, 2012, as compared to the year ended December 31, 2011.

Net gain (loss) on asset sales and inventory impairment. We incurred a loss on asset sales and inventory impairment of approximately $0.5 million for the year ended December 31, 2012, as compared to a loss of $0.2 million for the year ended December 31, 2011. The loss during 2012 was primarily related to the impairment of certain equipment held in inventory, mostly consisting of drilling rig parts. During the year ended December 31, 2011, the loss was primarily related to the sale of pipe and other equipment and the impairment of certain equipment held in inventory, mostly consisting of drilling rig parts.

Interest expense. 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 on certain qualifying projects for the year ended December 31, 2012 and expensed the remaining $1.0 million to operations. In February 2012, we repaid our borrowings then outstanding of $123.0 million under our Credit Agreement using a portion of the net proceeds received from our Initial Public Offering. From March 1 through December 31, 2012, we borrowed $150.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures. Our total outstanding borrowings at December 31, 2012 were $150.0 million, and the effective interest rate on the borrowings was approximately 3.3%. At December 31, 2011, we had total borrowings of $113.0 million outstanding under our Credit Agreement, and we incurred total interest expense of approximately $2.0 million. We capitalized approximately $1.3 million of our interest expense on certain qualifying projects for the year ended December 31, 2011 and expensed the remaining $0.7 million to operations.

Interest and other income. Our interest and other income decreased by approximately $0.1 million to approximately $0.2 million, or a decrease of about 29%, for the year ended December 31, 2012, as compared to the year ended December 31, 2011. The decrease in our interest and other income was due primarily to a decrease in the natural gas transportation income received from third parties during the year ended December 31, 2012, as compared to the year ended December 31, 2011. Our cash and certificates of deposit decreased to approximately $2.3 million at December 31, 2012 from approximately $11.6 million at December 31, 2011.

Total income tax provision (benefit). We recorded a total income tax benefit of approximately $1.4 million for the year ended December 31, 2012, as compared to a total income tax benefit of approximately $5.5 million for the year ended December 31, 2011. 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 cost center 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. The total income tax benefit for the year ended December 31, 2011 reflected deferred income taxes almost entirely, with the exception of a state of Louisiana income tax refund of approximately $46,000 recorded during this period. We had a net loss for the years ended December 31, 2012 and 2011.

LIQUIDITY AND CAPITAL RESOURCES

Prior to the consummation of our Initial Public Offering on February 7, 2012, our primary sources of liquidity were capital contributions from private investors, our cash flows from operations, borrowings under our Credit Agreement and the proceeds from a significant sale of a portion of our assets in the Haynesville shale in 2008. Our primary use of capital has been, and we expect will continue to be during 2014 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 continue to grow our operating cash flows.

At December 31, 2013, we had cash totaling approximately $6.3 million, the borrowing base under our Credit Agreement was $350.0 million and we had $200.0 million of outstanding long-term borrowings and approximately $0.3 million in outstanding letters of credit. These borrowings bore interest at an effective interest rate of approximately 3.3% per annum. On March 12, 2014 we amended our Credit Agreement to, among other things, increase the borrowing base to $385.0 million. From January 1 through March 13, 2014, we borrowed an additional $50.0 million under our Credit Agreement to finance a portion of our working capital requirements and capital expenditures. At March 13, 2014, we had $250.0 million of outstanding long-term borrowings and approximately $0.3 million in outstanding letters of credit.

On September 28, 2012, we entered into the third amended and restated credit agreement (the "Credit Agreement"), which increased the maximum facility amount to $500.0 million from $400.0 million. The borrowing base under the Credit Agreement is scheduled to be redetermined automatically on 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 each request an unscheduled redetermination of the borrowing base once between scheduled redetermination dates. On August 7, 2013, the borrowing base under the Credit Agreement was increased to $350.0 million from $280.0 million, based on the lenders' review of our proved oil and natural gas reserves at June 30, 2013. This August 2013 redetermination constituted the regularly scheduled November 1 redetermination. 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 as a result, 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, we amended the Credit Agreement to 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. This March 2014 redetermination constituted the regularly scheduled May 1 redetermination. We expect additional increases to the borrowing base will be primarily as a result of anticipated increases in our proved oil and natural gas reserves, and particularly our proved developed oil and natural gas reserves.

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 are using the net proceeds from this offering primarily to fund a portion of our capital expenditures, including for the addition of the third rig to our drilling program. We are also using 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 may be reborrowed in accordance with the terms of that facility for, among other items, the uses contemplated above.

Our 2014 capital expenditure budget is estimated at $440.0 million and includes approximately $394.0 million for drilling and completing oil and natural gas exploration and development wells, with the remainder allocated to lease acquisitions, seismic data, pipelines and other infrastructure. As a result of the receipt of the net proceeds of our September 2013 public equity offering, current availability and anticipated increases in the borrowing base under our Credit Agreement and our anticipated increases in oil and natural gas production and related revenues, excluding any possible significant acquisitions, we expect to have sufficient future borrowing capacity under our Credit Agreement and cash flows from operations to fund our capital expenditure requirements for 2014. 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. However, should our drilling activities be less successful than we anticipate or result in less growth in our proved oil and natural gas reserves or less cash flows than we anticipate, or should oil and natural gas prices decline substantially, we may require additional sources of financing, including through additional 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. To the extent such sources of financing are not available on terms reasonably acceptable to us, we may need to reduce our capital spending and rate of growth.

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. Although a significant portion of our anticipated cash flows from operations for 2014 is expected to come from development activities on currently proved properties in the Eagle Ford shale in South Texas, these development activities may be less successful than we anticipate. Further, a portion of our anticipated cash flows from operations during the year ending December 31, 2014 is expected to come from exploration activities in the Eagle Ford shale and in the Wolfcamp and Bone Spring plays in the Permian Basin, and these exploration activities 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 2014 and the hedges we currently have in place.

If our exploration and development activities result in less cash flows than anticipated, we may seek additional sources of capital, including through additional borrowings under our Credit Agreement, 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 2014 accordingly to 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 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, 2013, 2012 and 2011 are presented below:

	Year Ended December 31,		
	2013	2012	2011
(In thousands)			
Net cash provided by operating activities	$ 179,470	$ 124,228	$ 61,868
Net cash used in investing activities	(366,939)	(306,916)	(160,088)
Net cash provided by financing activities	191,661	174,499	87,444
Net change in cash	$ 4,192	$ (8,189)	$ (10,776)

Cash Flows Provided by Operating Activities

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, 2012 and December 31, 2013 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.

Net cash provided by operating activities increased by $62.3 million to $124.2 million for the year ended December 31, 2012, as compared to net cash provided by operating activities of $61.9 million for the year ended December 31, 2011. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased significantly to $114.9 million for the year ended December 31, 2012 from $49.3 million for the year ended December 31, 2011. This increase is primarily attributable to the almost eight-fold increase in our oil production to just over 1.2 million Bbl from approximately 154,000 Bbl during the respective periods. A portion of the increase in net cash provided by operating activities also reflects the higher weighted average oil price of $101.86 per Bbl realized during 2012, as compared to a weighted average oil price of $93.80 per Bbl realized during 2011. Changes in our operating assets and liabilities between December 31, 2011 and December 31, 2012 also resulted in a net decrease of approximately $3.3 million in net cash provided by operating activities for the year ended December 31, 2012, as compared to the year ended December 31, 2011. Our accounts payable and accrued liabilities increased to approximately $87.3 million at December 31, 2012 from approximately $44.3 million at December 31, 2011 due to our increased operating activity in South Texas. Our accounts receivable increased to $29.5 million at December 31, 2012, as compared to $13.2 million at December 31, 2011, due primarily to the increase in our oil production and associated revenues.

Our operating cash flows are sensitive to a number of variables, including changes in our production and volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, 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 position, 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 $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 includes 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 1,720 gross (1,660 net) acres in the Eagle Ford shale and 1,190 gross (1,190 net) acres in the Haynesville shale.

Net cash used in investing activities increased by $146.8 million to $306.9 million for the year ended December 31, 2012 from $160.1 million for the year ended December 31, 2011. This increase in net cash used in investing activities reflected an increase of $144.3 million in our oil and natural gas properties capital expenditures for the year ended December 31, 2012, as compared to the year ended December 31, 2011, and an increase of approximately $2.7 million in expenditures for other property and equipment, which included new pipeline infrastructure associated with our initial wells in the Eagle Ford shale. Approximately 91% of our capital expenditures were allocated to drilling and completion operations and associated infrastructure and 9% to the acquisition of additional acreage for the year ended December 31, 2012, as compared to approximately 75% allocated to drilling and completion operations and associated infrastructure and 25% allocated to acquisition of additional acreage for the year ended December 31, 2011. Our oil and natural gas properties capital expenditures for the year ended December 31, 2012 were primarily due to expenditures associated with our operated drilling and completion activities in the Eagle Ford shale, non-operated drilling and completion activities and acreage acquisitions in the Eagle Ford and Haynesville shale plays and our acreage acquisitions in the Permian Basin.

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 $440.0 million in capital for acquisition, exploration and development activities in 2014 as follows:

	Amount (in millions)
Exploration, development drilling and completion costs	$394.0
Pipeline and infrastructure expenditures	16.0
Leasehold acquisition and 2-D and 3-D seismic data	30.0
Total	$440.0

For further information regarding our anticipated 2014 capital expenditure budget, see "Business — General."

Our 2014 capital expenditures may be adjusted as business conditions warrant. The amount, timing and allocation of our capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline 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 $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 of our September 2013 public equity offering of $149.1 million and borrowings under our Credit Agreement of $180.0 million, offset by the costs of the offering of $7.4 million paid 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, as compared to net cash provided by financing activities of $87.4 million for the year ended December 31, 2011. 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.

Net cash provided by financing activities was $87.4 million for the year ended December 31, 2011. The net cash provided by financing activities for the year ended December 31, 2011 was due almost entirely to additional borrowings of $88.0 million under our Credit Agreement to fund a portion of our working capital requirements as well as our acquisition of acreage prospective for the Eagle Ford shale play in DeWitt, Gonzales, Karnes and Wilson Counties, Texas. In January 2011, we sold 53,772 shares of our Class A common stock in a private placement and received net proceeds of approximately $0.6 million. During 2011, we also received proceeds from the exercise of stock options totaling approximately $0.8 million. For the year ended December 31, 2011, we also incurred cash expenditures related to preparation for our Initial Public Offering of approximately $1.7 million.

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. 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 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 2013, the lenders completed their review of our proved oil and natural gas reserves at December 31, 2012, and on March 11, 2013, the borrowing base was increased from $215.0 million to $255.0 million. In connection with this borrowing base redetermination, the conforming borrowing base was increased to $220.0 million. At that time, we also amended the Credit Agreement to include Capital One, N.A., BMO Harris Financing, Inc. (Bank of Montreal) and Iberia Bank in our lending group, which also included Royal Bank of Canada (RBC), as administrative agent, Comerica Bank, Citibank, N.A., The Bank of Nova Scotia and SunTrust Bank. This March 2013 redetermination constituted the regularly scheduled May 1 redetermination. In late April 2013, we requested an unscheduled redetermination of the borrowing base, and on June 4, 2013, the borrowing base was increased from $255.0 million to $280.0 million, and the conforming borrowing base was increased to $245.0 million. On August 7, 2013, the borrowing base under the Credit Agreement was increased to $350.0 million and the conforming borrowing base was increased to $275.0 million. At that time, we amended the Credit Agreement to provide that the borrowing base would automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2014 or (ii) concurrent with the issuance by us of senior unsecured notes in an amount greater than or equal to $10.0 million. This August 2013 redetermination constituted the regularly scheduled November 1 redetermination.

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 as a result, 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 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. We may request one additional unscheduled redetermination of our borrowing base prior to the next scheduled redetermination. We expect additional increases to the borrowing base will be primarily as a result of anticipated increases in our proved oil and natural gas reserves, and particularly our proved developed oil and natural gas reserves.

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.

On September 12, 2013, using a portion of the net proceeds from our public equity offering, we repaid $130.0 million of outstanding borrowings under the Credit Agreement. At December 31, 2013, we had $200.0 million in borrowings outstanding under the Credit Agreement and approximately $0.3 million in outstanding letters of credit issued pursuant to the Credit Agreement. At December 31, 2013, our outstanding borrowings bore interest at an effective interest rate of approximately 3.3% per annum. We expect to access future borrowings under our Credit Agreement to fund our 2014 capital expenditure requirements in excess of amounts available from our operating cash flows. From January 1, 2014 through March 13, 2014, we borrowed an additional $50.0 million under the Credit Agreement to finance a portion of our working capital requirements and capital expenditures and the acquisition of additional leasehold interests. At March 13, 2014, we had $250.0 million in borrowings outstanding under the Credit Agreement and approximately $0.3 million in outstanding letters of credit issued pursuant to the Credit Agreement.

Under the terms of our Credit Agreement as of December 31, 2013 and until the March 12, 2014 amendment described above, if we borrowed funds as a base rate loan, such borrowings bore interest at a rate equal to the higher of (i) the prime rate for such day or (ii) the Federal Funds Effective Rate on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate plus 1.0% plus, in each case, an amount from 0.75% to 3.00% of such outstanding loan depending on the level of borrowings under the agreement. If we borrowed funds as a Eurodollar loan, such borrowings bore 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 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 1.75% to 4.00% 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 as interest expense and in our interest rate calculations and related disclosures. At December 31, 2013, the key financial covenants under the Credit Agreement required us to maintain (1) a current ratio, which is defined as consolidated total current assets plus the unused availability under the Credit Agreement divided by consolidated total current liabilities, of 1.0 or greater to be measured at the end of each fiscal quarter beginning June 30, 2014 and (2) a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.0 or less.

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.

At December 31, 2013, we believe that we were in compliance with the terms of our Credit Agreement.

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2013, we did not have any off-balance sheet arrangements.

OBLIGATIONS AND COMMITMENTS

We had the following material contractual obligations and commitments at December 31, 2013:

	Payment 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)	$200,300	$ 250	$200,050	$ —	$ —
Office lease	7,589	812	1,684	1,764	3,329
Non-operated drilling commitments (2)	5,666	5,666	—	—	—
Drilling rig contracts (3)	9,884	8,781	1,103	—	—
Asset retirement obligations	7,484	175	657	954	5,698
Natural gas processing and transportation agreement (4)	10,718	4,731	4,792	1,195	—
Total contractual cash obligations	$241,641	$20,415	$208,286	$3,913	$9,027

(1) At December 31, 2013, we had $200.0 million in revolving borrowings outstanding under our Credit Agreement and approximately $0.3 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, 2013, 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 most of these wells were in progress at December 31, 2013. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $5.7 million at December 31, 2013, which we expect to incur within the next few months.

(3) From time to time, we enter into contracts with third parties for 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 are typically for one year or less. Should we elect to terminate a contract and if the drilling contractor were unable to secure 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 $9.9 million at December 31, 2013.

(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 $10.7 million at December 31, 2013.

GENERAL OUTLOOK AND TRENDS

For the year ended December 31, 2013, oil prices ranged from a low of approximately $86.68 per Bbl in mid-April to a high of approximately $110.53 per Bbl in early September, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. The oil price at December 31, 2013 was $98.42 per Bbl. We realized a weighted average oil price of $99.79 per Bbl ($98.67 per Bbl including realized losses from oil derivatives) for our oil production for the year ended December 31, 2013, as compared to $101.86 per Bbl ($103.55 per Bbl including realized gains from oil derivatives)for the year ended December 31, 2012. At March 13, 2014, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date closed at $98.20 per Bbl, as compared to $92.52 per Bbl at March 13, 2013.

For the year ended December 31, 2013, natural gas prices ranged from a low of approximately $3.11 per MMBtu in early January to a high of approximately $4.46 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 $4.35 per Mcf ($4.47 per Mcf including realized gains from natural gas derivatives) for our natural gas production for the year ended December 31, 2013, as compared to $2.59 per Mcf ($3.55 per Mcf including realized gains from natural gas derivatives) for the year ended December 31, 2012. At March 13, 2014, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date closed at $4.38 per MMBtu, as compared to $3.68 per MMBtu at March 13, 2013.

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, we expect oil production from our properties in the Permian Basin will be 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. Should oil, natural gas or natural gas liquids prices decrease to economically unattractive levels and remain there for an extended period of time, we may elect to delay some of our exploration and development plans for our prospects, or cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities, each of which would have a material adverse effect on our business, financial condition, results of operations and reserves. 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, 2013. 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 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 average 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.

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 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 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 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, 2013. 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 at least annually 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 position, 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 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

Balance Sheet. In January 2013, the FASB issued Accounting Standards Update, or ASU, 2013-01, *Balance Sheet*. The ASU clarifies the scope of ASU 2011-11 to limit the application of ASU 2011-11 to derivatives accounted for in accordance with Accounting Standards Codification, or ASC, 815, *Derivatives and Hedging,* including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. We adopted ASU 2013-01 effective January 1, 2013, together with the adoption of ASU 2011-11. The adoption of ASUs 2013-01 and 2011-11 did not have a material effect on our consolidated financial statements, but did require certain additional disclosures (see "Note 11 — Derivative Financial Instruments" to the consolidated financial statements in this Annual Report on Form 10-K).

Balance Sheet. In December 2011, the FASB issued ASU 2011-11, *Balance Sheet*. The requirements amend the disclosure requirements to offsetting in ASC 210-20-50. The amendments require enhanced disclosures by requiring improved information about financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting agreement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. We adopted ASU 2011-11 effective January 1, 2013, together with the adoption of ASU 2013-01. The adoption of ASUs 2011-11 and 2013-01 did not have a material effect on our consolidated financial statements, but did require certain additional disclosures (see "Note 11 — Derivative Financial Instruments" to the consolidated financial statements in this Annual Report on Form 10-K).

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.

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, 2013, Comerica Bank, RBC, The Bank of Nova Scotia and SunTrust Bank (or affiliates thereof) were the counterparties for all of our derivative instruments. We have evaluated 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, 2013. 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 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. 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, 2013 we had $200.0 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 position, 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 March 13, 2014 were RBC, Comerica Bank, The Bank of Nova Scotia and SunTrust Bank (or affiliates thereof) and we are likely to enter into any future derivative instruments with RBC, Comerica Bank, The Bank of Nova Scotia, SunTrust Bank 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, 2013, 2012 and 2011. 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.

Not applicable.

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, 2013 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, 2013, 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 1992 "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.

Grant Thornton LLP, our independent registered public accounting firm, has issued an attestation report on our controls over financial reporting as of December 31, 2013 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.

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Matador Resources Company

We have audited the internal control over financial reporting of Matador Resources Company (a Texas corporation) and subsidiaries (collectively the "Company") as of December 31, 2013, based on criteria established in the 1992 *Internal Control — Integrated Framework* 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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, 2013, based on criteria established in the 1992 *Internal Control — Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2013, and our report dated March 17, 2014 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas
March 17, 2014

ITEM 9B. OTHER INFORMATION.

None.

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.

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, 2013 and 2012, Consolidated Statements of Operations for the Years Ended December 31, 2013, 2012 and 2011, Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011 and Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011.
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.

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).
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).
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).
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).
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).

Exhibit Number	Description
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).

Exhibit Number	Description
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	Participation Agreement, by and among MRC Rockies Company, Matador Resources Company (now known as MRC Energy Company), Matador Production Company, Roxanna Rocky Mountains, LLC, Roxanna Oil, Inc., Alliance Capital Real Estate, Inc. and AllianceBernstein L.P., dated at May 14, 2010 (incorporated by reference to Exhibit 10.23 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.30	Amendment, dated as of September 11, 2012, to Participation Agreement dated May 14, 2010, by and among MRC Rockies Company, Matador Resources Company (now known as MRC Energy Company), Matador Production Company, Roxanna Rocky Mountains, LLC, Roxanna Oil, Inc., Alliance Capital Real Estate, Inc. and Kimmeridge Energy Exploration Fund, L.P. (successor in interest to AllianceBernstein L.P.) (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
10.31	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).
10.32	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).
10.33†	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).
10.34†	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).
10.35†	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).

Exhibit Number	Description
10.36†	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).
10.37†	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).
10.38†	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).
10.39†	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).
10.40†	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).
10.41†	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).
10.42†	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).
10.43†	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).
10.44	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).
10.45	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).
10.46	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).

Exhibit Number	Description
10.47	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).
10.48	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).
10.49	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).
10.50	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 (filed herewith).
10.51†	Form of Employment Agreement between Matador Resources Company and each of Craig N. Adams and Ryan C. London (filed herewith).
21.1	List of Subsidiaries of Matador Resources Company (filed herewith).
23.1	Consent of Grant Thornton LLP (filed herewith).
23.2	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, 2013, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statement 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.

* In accordance with Rule 406T of Regulation S-T, the XBRL information in Exhibit 101 to this Annual Report on Form 10-K shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended ("Exchange Act"), or otherwise subject to the liability of that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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 17, 2014

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 17, 2014
/s/ DAVID E. LANCASTER David E. Lancaster	Executive Vice President, Chief Operating Officer and Chief Financial Officer (Principal Financial Officer)	March 17, 2014
/s/ SANDRA K. FENDLEY Sandra K. Fendley	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 17, 2014
/s/ STEPHEN A. HOLDITCH Stephen A. Holditch	Director	March 17, 2014
/s/ DAVID M. LANEY David M. Laney	Director	March 17, 2014
/s/ GREGORY E. MITCHELL Gregory E. Mitchell	Director	March 17, 2014
/s/ STEVEN W. OHNIMUS Steven W. Ohnimus	Director	March 17, 2014
/s/ MICHAEL C. RYAN Michael C. Ryan	Director	March 17, 2014
/s/ CARLOS M. SEPULVEDA, JR. Carlos M. Sepulveda, Jr.	Director	March 17, 2014
/s/ MARGARET B. SHANNON Margaret B. Shannon	Director	March 17, 2014

Glossary of Oil and Natural Gas Terms

The following is a description of the meanings of some of the oil and natural gas industry terms used in this Annual Report on Form 10-K.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this Annual Report on Form 10-K in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet.

BOE. Barrels of oil equivalent, determined using the ratio of one Bbl of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

BOE/d. BOE per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The operations required to establish production of oil or natural gas from a wellbore, usually involving perforations, stimulation and/or installation of permanent equipment in the well, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reservoir.

Conventional resources. Natural gas or oil that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the natural gas or oil to readily flow to the wellbore.

Coring. The act of taking a core. A core is a solid column of rock, usually from two to four inches in diameter, taken as a sample of an underground formation. It is common practice to take cores from wells in the process of being drilled. A core bit is attached to the end of the drill pipe. The core bit then cuts a column of rock from the formation being penetrated. The core is then removed and tested for evidence of oil or natural gas, and its characteristics (porosity, permeability, etc.) are determined.

Developed acreage. The number of acres that are allocated or assignable to productive wells.

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

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production-related expenses and taxes.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Farmin or farmout. An agreement under which the owner of a working interest in an oil or natural gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farmin" while the interest transferred by the assignor is a "farmout."

FERC. Federal Energy Regulatory Commission.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells in which a working interest is owned.

Held by production. An oil and natural gas property under lease in which the lease continues to be in force after the primary term of the lease in accordance with its terms as a result of production from the property.

Horizontal drilling or well. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation typically yields a horizontal well that has the ability to produce higher volumes than a vertical well drilled in the same formation. A horizontal well is designed to replace multiple vertical wells, resulting in lower capital expenditures for draining like acreage and limiting surface disruption.

Hydraulic fracturing. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to prop the channel open, so that fluids or gases may more easily flow from the formation, through the fracture channel and into the wellbore. This technique may also be referred to as fracture stimulation.

Liquids. Liquids, or natural gas liquids, are marketable liquid products including ethane, propane, butane and pentane resulting from the further processing of liquefiable hydrocarbons separated from raw natural gas by a natural gas processing facility.

MBbl. One thousand barrels of crude oil or other liquid hydrocarbons.

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NGL. Natural gas liquids.

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

Net revenue interest. The interest that defines the percentage of revenue that an owner of a well receives from the sale of oil, natural gas and/or natural gas liquids that are produced from the well.

NYMEX. New York Mercantile Exchange.

Overriding royalty interest. A fractional interest in the gross production of oil and natural gas under a lease, in addition to the usual royalties paid to the lessor, free of any expense for exploration, drilling, development, operating, marketing and other costs incident to the production and sale of oil and natural gas produced from the lease. It is an interest carved out of the lessee's working interest, as distinguished from the lessor's reserved royalty interest.

Permeability. A reference to the ability of oil and/or natural gas to flow through a reservoir.

Petrophysical analysis. The interpretation of well log measurements, obtained from a string of electronic tools inserted into the borehole, and from core measurements, in which rock samples are retrieved from the subsurface, then combining these measurements with other relevant geological and geophysical information to describe the reservoir rock properties.

Play. A set of known or postulated oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathways, timing, trapping mechanism and hydrocarbon type.

Possible reserves. Additional reserves that are less certain to be recognized than probable reserves.

Probable reserves. Additional reserves that are less certain to be recognized than proved reserves but which, in sum with proved reserves, are as likely as not to be recovered.

Producing well, or productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the well's production exceed production-related expenses and taxes.

Properties. Natural gas and oil wells, production and related equipment and facilities and natural gas, oil or other mineral fee, leasehold and related interests.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and preliminary economic analysis using reasonably anticipated prices and costs, is considered to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing. Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending installation of surface equipment or gathering facilities, or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved but non-producing reserves.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

Proved reserves. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

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

Recompletion. Completing in the same wellbore to reach a new reservoir after production from the original reservoir has been abandoned.

Repeatability. The potential ability to drill multiple wells within a prospect or trend.

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

Royalty interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

2-D seismic. The method by which a cross-section of the earth's subsurface is created through the interpretation of reflecting seismic data collected along a single source profile.

3-D seismic. The method by which a three-dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do 2-D seismic surveys and contribute significantly to field appraisal, exploitation and production.

Spud. The act of beginning to drill an oil or natural gas well.

Trend. A region of oil and/or natural gas production, the geographic limits of which have not been fully defined, having geological characteristics that have been ascertained through supporting geological, geophysical or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.

Unconventional resource play. A set of known or postulated oil and or natural gas resources or reserves warranting further exploration which are extracted from (i) low-permeability sandstone and shale formations and (ii) coalbed methane. These plays require the application of advanced technology to extract the oil and natural gas resources.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage is usually considered to be all acreage that is not allocated or assignable to productive wells.

Unproved and unevaluated properties. Properties where no drilling or other actions have been undertaken that permit such property to be classified as proved.

Vertical well. A hole drilled vertically into the earth from which oil, natural gas or water flows or is pumped.

Visualization. An exploration technique in which the size and shape of subsurface features are mapped and analyzed based upon information derived from well logs, seismic data and other well information.

Volumetric reserve analysis. A technique used to estimate the amount of recoverable oil and natural gas. It involves calculating the volume of reservoir rock and adjusting that volume for rock porosity, hydrocarbon saturation, formation volume factor and recovery factor.

Wellbore. The hole made by a well.

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

Consolidated Financial Statements

MATADOR RESOURCES COMPANY AND SUBSIDIARIES
December 31, 2013, 2012 and 2011

Contents *Page*

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Matador Resources Company

We have audited the accompanying consolidated balance sheets of Matador Resources Company (a Texas corporation) and subsidiaries (collectively the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, changes in shareholders' equity and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Matador Resources Company and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in 1992 *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 17, 2014 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
March 17, 2014

Consolidated Balance Sheets

Matador Resources Company and Subsidiaries

	December 31, 2013	December 31, 2012
(In thousands, except par value and share data)		
ASSETS		
Current assets		
Cash	$ 6,287	$ 2,095
Certificates of deposit	—	230
Accounts receivable		
Oil and natural gas revenues	25,823	24,422
Joint interest billings	4,785	4,118
Other	1,066	974
Derivative instruments	19	4,378
Deferred income taxes	1,636	—
Lease and well equipment inventory	785	877
Prepaid expenses	1,771	1,103
Total current assets	42,172	38,197
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	1,090,656	763,527
Unproved and unevaluated	194,306	149,675
Other property and equipment	29,910	27,258
Less accumulated depletion, depreciation and amortization	(468,995)	(349,370)
Net property and equipment	845,877	591,090
Other assets		
Derivative instruments	173	771
Deferred income taxes	—	411
Other assets	2,108	1,560
Total other assets	2,281	2,742
Total assets	$ 890,330	$ 632,029
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 25,358	$ 28,120
Accrued liabilities	63,987	59,179
Royalties payable	7,798	6,541
Derivative instruments	2,692	670
Advances from joint interest owners	—	1,515
Deferred income taxes	—	411
Income taxes payable	404	—
Other current liabilities	88	56
Total current liabilities	100,327	96,492
Long-term liabilities		
Borrowings under Credit Agreement	200,000	150,000
Asset retirement obligations	7,309	5,109
Derivative instruments	253	—
Deferred income taxes	10,929	—
Other long-term liabilities	2,588	1,324
Total long-term liabilities	221,079	156,433
Commitments and contingencies (Note 13)		
Shareholders' equity		
Common stock — Class A, $0.01 par value, 80,000,000 shares authorized; 66,958,867 and 56,778,718 shares issued; and 65,652,690, and 55,577,667 shares outstanding, respectively	670	568
Additional paid-in capital	548,935	404,311
Retained earnings (deficit)	30,084	(15,010)
Treasury stock, at cost, 1,306,177 and 1,201,051 shares, respectively	(10,765)	(10,765)
Total shareholders' equity	568,924	379,104
Total liabilities and shareholders' equity	$ 890,330	$ 632,029

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

Consolidated Statements of Operations

Matador Resources Company and Subsidiaries

(In thousands, except per share data)	For the Years Ended December 31, 2013	2012	2011
Revenues			
Oil and natural gas revenues	$269,030	$155,998	$ 67,000
Realized (loss) gain on derivatives	(909)	13,960	7,106
Unrealized (loss) gain on derivatives	(7,232)	(4,802)	5,138
Total revenues	260,889	165,156	79,244
Expenses			
Production taxes and marketing	20,973	11,672	6,278
Lease operating	38,720	28,184	7,244
Depletion, depreciation and amortization	98,395	80,454	31,754
Accretion of asset retirement obligations	348	256	209
Full-cost ceiling impairment	21,229	63,475	35,673
General and administrative	20,779	14,543	13,394
Total expenses	200,444	198,584	94,552
Operating income (loss)	60,445	(33,428)	(15,308)
Other income (expense)			
Net loss on asset sales and inventory impairment	(192)	(485)	(154)
Interest expense	(5,687)	(1,002)	(683)
Interest and other income	225	224	315
Total other expense	(5,654)	(1,263)	(522)
Income (loss) before income taxes	54,791	(34,691)	(15,830)
Income tax provision (benefit)			
Current	404	—	(46)
Deferred	9,293	(1,430)	(5,475)
Total income tax provision (benefit)	9,697	(1,430)	(5,521)
Net income (loss)	$ 45,094	$ (33,261)	$(10,309)
Earnings (loss) per common share			
Basic			
Class A	$ 0.77	$ (0.62)	$ (0.25)
Class B	$ —	$ (0.35)	$ 0.02
Diluted			
Class A	$ 0.77	$ (0.62)	$ (0.25)
Class B	$ —	$ (0.35)	$ 0.02
Weighted average common shares outstanding			
Basic			
Class A	58,777	53,852	41,687
Class B	—	105	1,031
Total	58,777	53,957	42,718
Diluted			
Class A	58,929	53,852	41,687
Class B	—	105	1,031
Total	58,929	53,957	42,718

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

Consolidated Statements of Changes in Shareholders' Equity

Matador Resources Company and Subsidiaries

	For the Years Ended December 31, 2013, 2012 and 2011								
	Common Stock				Additional paid-in capital	Retained earnings (deficit)	Treasury Stock		Total
	Class A		Class B						
	Shares	Amount	Shares	Amount			Shares	Amount	
(In thousands)									
Balance at January 1, 2011	42,750	$427	1,031	$ 10	$263,342	$ 28,863	1,179	$(10,765)	$281,877
Issuance of Class A common stock	54	1	—	—	591	—	—	—	592
Cost to issue equity	—	—	—	—	(1,667)	—	—	—	(1,667)
Issuance of Class A common stock to Board members and advisors	20	—	—	—	230	—	—	—	230
Stock options exercised	93	1	—	—	1,022	—	—	—	1,023
Restricted stock vested	—	—	—	—	44	—	—	—	44
Class B dividends declared	—	—	—	—	—	(275)	—	—	(275)
Current period net loss	—	—	—	—	—	(10,309)	—	—	(10,309)
Balance at December 31, 2011	42,917	429	1,031	10	263,562	18,279	1,179	(10,765)	271,515
Issuance of Class A common stock	12,209	122	—	—	146,388	—	—	—	146,510
Cost to issue equity	—	—	—	—	(11,268)	—	—	—	(11,268)
Conversion of Class B common stock to Class A common stock	1,031	10	(1,031)	(10)	—	—	—	—	—
Issuance of Class A common stock to Board members and advisors	7	—	—	—	71	—	—	—	71
Stock options expense related to equity-based awards	—	—	—	—	432	—	—	—	432
Stock options exercised	296	3	—	—	3,541	—	—	—	3,544
Liability-based stock option awards settled	—	—	—	—	216	—	—	—	216
Changes in fair value for liability-based awards for which grant date fair value is in excess of fair value	—	—	—	—	620	—	—	—	620
Restricted stock issued	319	4	—	—	(4)	—	—	—	—
Restricted stock forfeited	—	—	—	—	(29)	—	22	—	(29)
Restricted stock and restricted stock units expense	—	—	—	—	758	—	—	—	758
Swing sale profit contribution	—	—	—	—	24	—	—	—	24
Class B dividends declared	—	—	—	—	—	(28)	—	—	(28)
Current period net loss	—	—	—	—	—	(33,261)	—	—	(33,261)
Balance at December 31, 2012	56,779	568	—	—	404,311	(15,010)	1,201	(10,765)	379,104
Issuance of common stock	9,780	98	—	—	148,971	—	—	—	149,069
Cost to issue equity	—	—	—	—	(7,390)	—	—	—	(7,390)
Common stock issued to Board advisors	22	—	—	—	57	—	—	—	57
Stock options expense related to equity-based awards	—	—	—	—	1,232	—	—	—	1,232
Liability-based stock option awards settled	—	—	—	—	162	—	—	—	162
Restricted stock issued	378	4	—	—	(4)	—	—	—	—
Restricted stock forfeited	—	—	—	—	(22)	—	105	—	(22)
Restricted stock and restricted stock units expense	—	—	—	—	1,618	—	—	—	1,618
Current period net income	—	—	—	—	—	45,094	—	—	45,094
Balance at December 31, 2013	66,959	$670	—	$ —	$548,935	$ 30,084	1,306	$(10,765)	$568,924

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

Consolidated Statements of Cash Flows

Matador Resources Company and Subsidiaries

	For the Years Ended December 31,		
	2013	2012	2011
(In thousands)			
Operating activities			
Net income (loss)	$ 45,094	$ (33,261)	$ (10,309)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Unrealized loss (gain) on derivatives	7,232	4,802	(5,138)
Depletion, depreciation and amortization	98,395	80,454	31,754
Accretion of asset retirement obligations	348	256	209
Full-cost ceiling impairment	21,229	63,475	35,673
Stock-based compensation expense	3,897	140	2,406
Deferred income tax provision (benefit)	9,293	(1,430)	(5,475)
Loss on asset sales and inventory impairment	192	485	154
Changes in operating assets and liabilities			
Accounts receivable	(2,160)	(16,342)	(1,523)
Lease and well equipment inventory	243	50	21
Prepaid expenses	(668)	50	650
Other assets	(548)	(673)	(814)
Accounts payable, accrued liabilities and other current liabilities	(3,638)	19,740	13,497
Royalties payable	1,257	4,685	873
Advances from joint interest owners	(1,515)	1,515	(723)
Income taxes payable	404	—	—
Other long-term liabilities	415	282	613
Net cash provided by operating activities	179,470	124,228	61,868
Investing activities			
Oil and natural gas properties capital expenditures	(363,192)	(300,689)	(156,431)
Expenditures for other property and equipment	(3,977)	(7,332)	(4,671)
Purchases of certificates of deposit	(61)	(496)	(4,298)
Maturities of certificates of deposit	291	1,601	5,312
Net cash used in investing activities	(366,939)	(306,916)	(160,088)
Financing activities			
Repayments of borrowings under Credit Agreement	(130,000)	(123,000)	(103,000)
Borrowings under Credit Agreement	180,000	160,000	191,000
Proceeds from issuance of common stock	149,069	146,510	592
Swing sale profit contribution	—	24	—
Cost to issue equity	(7,390)	(11,599)	(1,710)
Proceeds from stock options exercised	—	2,660	837
Taxes paid related to net share settlement of stock-based compensation	(18)	—	—
Payment of dividends — Class B	—	(96)	(275)
Net cash provided by financing activities	191,661	174,499	87,444
Increase (decrease) in cash	4,192	(8,189)	(10,776)
Cash at beginning of year	2,095	10,284	21,060
Cash at end of year	$ 6,287	$ 2,095	$ 10,284

Supplemental disclosures of cash flow information (Note 14)

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

MATADOR RESOURCES COMPANY AND SUBSIDIARIES
December 31, 2013, 2012 and 2011

NOTE 1 — NATURE OF OPERATIONS

Matador Resources Company ("Matador" and, collectively with its subsidiaries, the "Company") is 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. Matador's 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. The Company also operates in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. In addition, Matador has a large exploratory leasehold position in Southwest Wyoming and adjacent areas in Utah and Idaho where the Company is testing the Meade Peak shale.

On November 22, 2010, the company formerly known as Matador Resources Company, a Texas corporation founded on July 3, 2003, formed a wholly-owned subsidiary, Matador Holdco, Inc. Pursuant to the terms of a corporate reorganization that was completed on August 9, 2011 and in connection with its initial public offering, the former Matador Resources Company became a wholly-owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

MRC Energy Company holds the primary assets of the Company and has four wholly-owned subsidiaries: Matador Production Company, MRC Permian Company, MRC Rockies Company and Longwood Gathering and Disposal Systems GP, Inc. Matador Production Company serves as the oil and natural gas operating entity. MRC Permian Company conducts oil and natural gas exploration and development activities in Southeast New Mexico and West Texas. MRC Rockies Company conducts oil and natural gas exploration and development activities in the Rocky Mountains and specifically in the states of Wyoming, Utah and Idaho. Longwood Gathering and Disposal Systems GP, Inc. serves as the general partner of Longwood Gathering and Disposal Systems, LP, which owns a majority of the pipeline systems and salt water disposal wells used in the Company's operations, transports limited quantities of third-party natural gas and disposes of limited quantities of third-party salt water.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the accounts of Matador Resources Company and its wholly-owned subsidiary, MRC Energy Company, as well as the accounts of MRC Energy Company's four wholly-owned subsidiaries, Matador Production Company, Longwood Gathering and Disposal Systems GP, Inc., MRC Permian Company and MRC Rockies Company, and the accounts of Longwood Gathering and Disposal Systems, LP. These consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP"). The Company's operations are conducted in the one segment generally referred to as the oil and natural gas exploration and production industry. All significant intercompany balances and transactions have been eliminated in consolidation.

Reclassifications

Certain reclassifications have been made to the prior years' financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

The Company's consolidated financial statements are based on a number of significant estimates, including oil and natural gas revenues, accrued assets and liabilities, stock-based compensation, valuation of derivative instruments, deferred tax assets and liabilities and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. The Company's oil and natural gas reserves estimates, which are inherently imprecise and based upon many factors that are beyond the Company's control, including oil and natural gas prices, are prepared by the Company's engineering staff in accordance with guidelines established by the Securities and Exchange Commission ("SEC") and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Certificates of Deposit

Certificates of deposit ("CDs") are highly liquid, short-term investments with an original maturity of more than 30 days but not more than one year. Each CD was recorded at market and was fully insured by the Federal Deposit Insurance Corporation.

Accounts Receivable

The Company sells its operated oil, natural gas and natural gas liquids production to various purchasers (see " — Revenue Recognition" below). Due to the nature of the markets for oil, natural gas and natural gas liquids, the Company does not believe that the loss of any one purchaser would significantly impact operations. In addition, the Company may participate with industry partners in the drilling, completion and operation of oil and natural gas wells. Substantially all of the Company's accounts receivable are due from either purchasers of oil, natural gas and natural gas liquids or participants in oil and natural gas wells for which the Company serves as the operator. Accounts receivable are due within 30 to 60 days of the production date and 30 days of the billing date, respectively, and are stated at amounts due from purchasers and industry partners. Amounts are considered past due if they have been outstanding for 60 days or more. No interest is typically charged on past due amounts.

The Company reviews its need for an allowance for doubtful accounts on a periodic basis, and determines the allowance, if any, by considering the length of time past due, previous loss history, future net revenues of the debtor's ownership interest in oil and natural gas properties operated by the Company and the debtor's ability to pay its obligations, among other things. The Company has no allowance for doubtful accounts related to its accounts receivable for any reporting period presented.

Lease and Well Equipment Inventory

Lease and well equipment inventory is stated at the lower of cost or market and consists entirely of equipment scheduled for use in future well operations or equipment held for sale.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Property and Equipment

The Company uses the full-cost method of accounting for its 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 and accumulated in a single cost center representing the Company's 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 acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized $3.7 million, $2.6 million and $2.0 million of its general and administrative costs in 2013, 2012 and 2011, respectively. The Company capitalized $1.9 million, $1.6 million and $1.3 million of its interest expense for the years ended December 31, 2013, 2012 and 2011, respectively.

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 the Company's net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. Since January 1, 2011, the need for a full-cost ceiling impairment is required to be assessed on a quarterly basis. The fair value of the Company's derivative instruments is not included in the ceiling test computation as the Company does 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 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 prices that represent the arithmetic average of the first-day-of-the-month price for the 12-month period prior to the end of each quarterly period and dictate that a 10% discount factor be used. For the period from January through December 2013, these average oil and natural gas prices were $93.42 per barrel and $3.670 per MMBtu, respectively. For the period from January through December 2012, these average oil and natural gas prices were $91.21 per barrel and $2.757 per MMBtu, respectively. For the period from January through December 2011, these average oil and natural gas prices were $92.71 per barrel and $4.118 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were further adjusted by property for quality, transportation fees and regional price differentials, and the average natural gas prices were further adjusted by property for energy content, transportation and marketing fees and regional price differentials.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

At March 31, 2013, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $13.7 million. The Company recorded an impairment charge of $21.2 million to its net capitalized costs and a deferred income tax credit of $7.5 million related to the full-cost ceiling limitation. These charges are reflected in the Company's consolidated statement of operations for the year ended December 31, 2013.

At June 30, 2012, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $21.3 million. The Company recorded an impairment charge of $33.2 million to its net capitalized costs and a deferred income tax credit of $11.9 million related to the full-cost ceiling limitation. At September 30, 2012, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $2.3 million. The Company recorded an impairment charge of $3.6 million to its net capitalized costs and a deferred income tax credit of $1.3 million related to the full-cost ceiling limitation. At December 31, 2012, the Company's net capitalized costs exceeded the full-cost center ceiling by $17.3 million. The Company recorded an impairment charge of $26.7 million to its net capitalized costs and a deferred income tax credit of $9.4 million related to the full-cost ceiling limitation. These charges for the second, third and fourth quarters of 2012 are reflected in the Company's consolidated statement of operations for the year ended December 31, 2012.

At March 31, 2011, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling by $23.0 million. The Company recorded an impairment charge of $35.7 million to its net capitalized costs and a deferred income tax credit of $12.7 million related to the full-cost ceiling limitation. These charges are reflected in the Company's consolidated statement of operations for the year ended December 31, 2011.

As a non-cash item, the full-cost ceiling impairment impacts the accumulated depletion and the net carrying value of the Company's assets on its balance sheet, as well as the corresponding shareholders' equity, but it has no impact on the Company's net cash flows as reported. Changes in oil and natural gas production rates, oil and natural gas prices, reserves estimates, future development costs and other factors will determine the Company's actual ceiling test computation and impairment analyses in future periods.

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. Unproved and unevaluated properties are assessed for possible 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 determination that the well is not productive.

Sales of oil and natural gas properties are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and natural gas. All costs related to production activities and maintenance and repairs are expensed as incurred. Significant workovers that increase the properties' reserves are capitalized.

Other property and equipment are recorded at historical cost. Computer equipment, furniture, software and other equipment are depreciated over their useful life (five to 10 years) using the straight-line method. Support equipment and facilities include the pipelines and salt water disposal systems owned by Longwood Gathering and Disposal Systems, LP and are depreciated over a 30-year useful life using the straight-line, mid-month convention method. Leasehold improvements are depreciated over the lesser of their useful lives or the term of the lease.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Asset Retirement Obligations

The Company recognizes the fair value of an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The asset retirement obligation is recorded as a liability at its estimated present value, with an offsetting increase recognized in oil and natural gas properties or support equipment and facilities on the balance sheet. Periodic accretion of the discounted value of the estimated liability is recorded as an expense in the consolidated statement of operations. In general, the Company's future asset retirement obligations relate to future costs associated with plugging and abandonment of its oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The amounts recognized are based on numerous estimates and assumptions, including future retirement costs, future recoverable quantities of oil and natural gas, future inflation rates and the Company's credit-adjusted risk-free interest rate. Revisions to the liability can occur due to changes in its estimate or if federal or state regulators enact new plugging and abandonment requirements. At the time of actual plugging and abandonment of its oil and natural gas wells, the Company includes any gain or loss associated with the operation in the amortization base to the extent that the actual costs are different from the estimated liability.

Derivative Financial Instruments

From time to time, the Company uses derivative financial instruments to mitigate its 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 the Company 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 the Company. 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. The Company's derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments, and as a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statement of operations (see Note 11). The fair value of the Company's derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value 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 and unrealized gains and unrealized losses from valuation changes in the remaining unsettled derivative financial instruments are reported under "Revenues" in the consolidated statement of operations.

Revenue Recognition

The Company follows the sales method of accounting for its oil, natural gas and natural gas liquids revenues, whereby it recognizes revenue, net of royalties, on all oil, natural gas and natural gas liquids sold to purchasers regardless of whether the sales are proportionate to its ownership in the property. Under this method, revenue is recognized at the time oil, natural gas and natural gas liquids are produced and sold, and the Company accrues for revenue earned but not yet received.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

For the year ended December 31, 2013, the Company had five significant purchasers that accounted for approximately 87% of its total oil, natural gas and natural gas liquids revenues. For the years ended December 31, 2012 and 2011, the Company had three significant purchasers that accounted for approximately 74% and 60%, respectively, of its total oil, natural gas and natural gas liquids revenues. Due to the nature of the markets for oil, natural gas and natural gas liquids, the Company does not believe the loss of any one purchaser would have a material adverse impact on the Company's financial position, results of operations or cash flows for any significant period of time. At December 31, 2013, 2012 and 2011, approximately 81%, 67% and 52%, respectively, of the Company's accounts receivable, including joint interest billings, related to these purchasers.

Stock-Based Compensation

Effective January 1, 2012, the Board of Directors adopted the 2012 Long-Term Incentive Plan (the "2012 Incentive Plan"). The 2012 Incentive Plan was also approved by the Company's shareholders at its Annual Meeting of Shareholders on June 7, 2012. During 2013 and 2012, all stock option awards granted under the 2012 Incentive Plan were non-qualified options and the associated compensation expense is recognized over the vesting period, which is typically three or four years. All stock option awards granted in 2013 and 2012 are classified as equity instruments due to the methods of exercise specified in the 2012 Incentive Plan. Compensation expense for restricted stock and restricted stock unit grants awarded in 2013 and 2012 was recognized immediately or over the vesting period, which is typically one to four years.

The Company did not grant any stock option awards in 2011. Prior to 2011, all stock option awards were granted under the 2003 Stock and Incentive Plan (the "2003 Plan"), and since November 22, 2010, these awards have been accounted for as liability instruments. No additional stock-based compensation will be awarded under the 2003 Plan. Non-qualified stock option grants awarded under the 2003 Plan typically vested upon issuance, while incentive stock option grants awarded under the 2003 Plan typically vest over four years, and the associated compensation expense is recognized on a straight-line basis over the vesting period. Compensation expense for restricted stock grants awarded under the 2003 Plan was recognized immediately or over the vesting period, which was typically three years.

At December 31, 2013, 2012 and 2011, the Company used the fair value method to measure and recognize the liability and equity associated with its outstanding stock options.

Prior to November 22, 2010, all of the Company's then-outstanding stock options were classified as equity instruments, with all stock-based compensation expense measured on the date of grant and recognized over the vesting period, if any. On November 22, 2010, the Company changed its method of accounting for its then-outstanding stock options, reclassifying all of its then-outstanding stock options from equity to liability instruments. This change was made as a result of the Company purchasing shares from certain of its employees to assist them in the exercise of outstanding options of the Company's Class A common stock. At December 31, 2013, the Company continues to account for all outstanding stock options granted under the 2003 Plan as liability instruments.

The Company's consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011 include a stock-based compensation (non-cash) expense of $3.9 million, $0.1 million and $2.4 million, respectively. This stock-based compensation expense includes common stock issuances and restricted stock units expense totaling $0.3 million, $0.1 million and $0.2 million in 2013, 2012 and 2011, respectively, paid to members of the Board of Directors and advisors as compensation for their services to the Company.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Income Taxes

The Company accounts for income taxes using the asset and liability approach for financial accounting and reporting. The Company evaluates the probability of realizing the future benefits of its deferred tax assets and provides 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.

The Company recognizes the tax benefit of an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities based on the technical merits of the position. 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. Management believes that the material positions taken by the Company would more likely than not be sustained by examination. At December 31, 2013 and 2012, the Company had not established any reserves for, nor recorded any unrecognized tax benefits related to, uncertain tax positions.

When necessary, the Company would include interest assessed by taxing authorities in "Interest expense" and penalties related to income taxes in "Other expense" on its consolidated statements of operations. The Company did not record any interest or penalties related to income tax for the years ended December 31, 2013, 2012 and 2011.

Earnings Per Common Share

The Company reports basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities, unless their impact is anti-dilutive.

Prior to consummation of the Company's initial public offering (the "Initial Public Offering") (see Note 10) in February 2012, the Company had issued two classes of common stock, Class A and Class B. The holders of the Class B shares were entitled to be paid cumulative dividends at a per share rate of $0.26-2/3 annually out of funds legally available for the payment of dividends. These dividends were accrued and paid quarterly. Dividends declared during 2012 totaled $27,643. Dividends declared during 2011 totaled $274,853. Class B dividends declared during the fourth quarter of 2011 and the first quarter of 2012 were paid during the first quarter of 2012 totaling $96,356. As of December 31, 2013, the Company has not paid any dividends to holders of the Class A shares. Concurrent with the completion of the Initial Public Offering, all 1,030,700 shares of the Company's Class B common stock were converted to Class A common stock on a one-for-one basis. The Class A common stock is now referred to as the "common stock."

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

The following are reconciliations of the numerators and denominators used to compute the Company's basic and diluted distributed and undistributed earnings per common share as reported for the years ended December 31, 2013, 2012 and 2011 (in thousands, except per share data).

	Year Ended December 31,		
	2013	2012	2011
Net income (loss) — numerator			
Net income (loss)	$45,094	$(33,261)	$(10,309)
Less dividends to Class B shareholders — distributed earnings	—	(28)	(275)
Undistributed earnings (loss)	$45,094	$(33,289)	$(10,584)
Weighted average common shares outstanding — denominator			
Basic			
Class A	58,777	53,852	41,687
Class B	—	105	1,031
Total	58,777	53,957	42,718
Diluted			
Class A			
Weighted average common shares outstanding for basic earnings (loss) per share	58,777	53,852	41,687
Dilutive effect of options and restricted stock units	152	—	—
Class A weighted average common shares outstanding — diluted	58,929	53,852	41,687
Class B			
Weighted average common shares outstanding — no associated dilutive shares	—	105	1,031
Total diluted weighted average common shares outstanding	58,929	53,957	42,718

	Year Ended December 31,		
	2013	2012	2011
Earnings (loss) per common share			
Basic			
Class A			
Distributed earnings	$ —	$ —	$ —
Undistributed earnings (loss)	$0.77	$(0.62)	$(0.25)
Total	$0.77	$(0.62)	$(0.25)
Class B			
Distributed earnings	$ —	$ 0.27	$ 0.27
Undistributed earnings (loss)	$ —	$(0.62)	$(0.25)
Total	$ —	$(0.35)	$ 0.02
Diluted			
Class A			
Distributed earnings	$ —	$ —	$ —
Undistributed earnings (loss)	$0.77	$(0.62)	$(0.25)
Total	$0.77	$(0.62)	$(0.25)
Class B			
Distributed earnings	$ —	$ 0.27	$ 0.27
Undistributed earnings (loss)	$ —	$(0.62)	$(0.25)
Total	$ —	$(0.35)	$ 0.02

A total of 1,067,069 and 1,024,500 options to purchase shares of the Company's Class A common stock and 162,368 and zero restricted stock units were excluded from the calculations above for the years ended December 31, 2012 and 2011, respectively, because their effects were anti-dilutive. Additionally, 305,807 restricted shares, which

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

are participating securities, were excluded from the calculations above for the year ended December 31, 2012 as the security holders do not have the obligation to share in the losses of the Company. There were no participating securities at December 31, 2011.

Fair Value Measurements

The Company measures and reports certain assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company follows Financial Accounting Standards Board ("FASB") guidance establishing a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value.

Credit Risk

The Company's cash is held in financial institutions and at times these amounts exceed the insurance limits of the Federal Deposit Insurance Corporation. Management believes, however, that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

The Company uses derivative financial instruments to mitigate its exposure to oil, natural gas and natural gas liquids price volatility. These transactions expose the Company to potential credit risk from its counterparties. Accounts receivable constitute the principal component of additional credit risk to which the Company may be exposed. The Company believes that any credit risk posed is insignificant and is offset by the creditworthiness of its customer base and industry partners.

Risks and Uncertainties

As an oil and natural gas exploration and production company focused on finding and developing its own prospects and reserves, the Company's success is highly dependent on the results of its exploration and development program. Exploration activities involve numerous risks, including the risk that no commercially productive oil or natural gas reserves will be discovered. In addition, there are uncertainties as to the future costs or timing of drilling, completing and producing wells. Poor results from the Company's exploration and development activities could limit the Company's ability to replace and grow reserves and materially and adversely affect the Company's financial position, results of operations and cash flows.

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 of that data can vary. The process also requires certain economic assumptions, including, but not limited to, oil and natural gas prices, drilling, completion and 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 most likely will vary from the Company's estimates. Any significant variance could materially and adversely affect the Company's future reserves estimates, financial position, results of operations and cash flows.

Historically, the market for oil, natural gas and natural gas liquids has experienced significant price fluctuations, and this has been particularly evident in recent years. Oil, natural gas and natural gas liquids prices are impacted by supply and demand, both domestic and international, seasonal variations caused by changing weather conditions, political conditions, governmental regulations, the availability, proximity and capacity of gathering, processing and transportation systems for natural gas and natural gas liquids and numerous other factors. Increases or decreases in prices received could have a significant and material impact on the Company's future reserves estimates, financial position, results of operations and cash flows.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

To mitigate its exposure to fluctuations in oil, natural gas and natural gas liquids prices, the Company, from time to time, enters into hedging arrangements with respect to a portion of its oil, natural gas and natural gas liquids production. Decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and the Company's forecast of future production and commodity prices, and the Company may not always employ the optimal hedging strategy.

The federal, state and local governments in the areas in which the Company operates or has assets impose taxes on the oil and natural gas products sold, and sales and use taxes are charged on significant portions of the Company's drilling, completion 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 in federal laws on the income taxation of small oil and natural gas exploration and production companies like the Company. Among other issues, President Obama has proposed to eliminate allowing small oil and natural gas companies to deduct intangible drilling costs as incurred and percentage depletion. Changes to tax laws could materially and adversely affect the Company's future financial position, results of operations and cash flows.

Recent Accounting Pronouncements

Balance Sheet. In January 2013, the FASB issued Accounting Standards Update, or ASU, 2013-01, *Balance Sheet.* The ASU clarifies the scope of ASU 2011-11 to limit the application of ASU 2011-11 to derivatives accounted for in accordance with Accounting Standards Codification, or ASC, 815, *Derivatives and Hedging,* including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. The Company adopted ASU 2013-01 effective January 1, 2013, together with the adoption of ASU 2011-01. The adoption of ASUs 2013-01 and 2011-11 did not have a material effect on the Company's consolidated financial statements, but did require certain additional disclosures (see Note 11).

Balance Sheet. In December 2011, the FASB issued ASU 2011-11, *Balance Sheet.* The requirements amend the disclosure requirements to offsetting in ASC 210-20-50. The amendments require enhanced disclosures by requiring improved information about financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting agreement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. The Company adopted ASU 2011-11 effective January 1, 2013, together with the adoption of ASU 2013-01. The adoption of ASUs 2011-11 and 2013-01 did not have a material effect on the Company's consolidated financial statements, but did require certain additional disclosures (see Note 11).

NOTE 3 — PROPERTY AND EQUIPMENT

The following table presents a summary of the Company's property and equipment balances as of December 31, 2013 and 2012 (in thousands).

	December 31, 2013	December 31, 2012
Oil and natural gas properties		
Evaluated (subject to amortization)	$1,090,656	$ 763,527
Unproved and unevaluated (not subject to amortization)		
Incurred in 2013	82,628	—
Incurred in 2012	23,341	36,488
Incurred in 2011	10,982	24,138
Incurred in 2010 and prior	77,355	89,049
Total unproved and unevaluated	194,306	149,675
Total oil and natural gas properties	1,284,962	913,202
Accumulated depletion	(463,091)	(344,609)
Net oil and natural gas properties	821,871	568,593
Other property and equipment		
Computer equipment	1,044	834
Furniture	1,057	793
Software	1,456	1,355
Other equipment	252	196
Leasehold improvements	991	644
Support equipment and facilities	25,110	23,436
Total other property and equipment	29,910	27,258
Accumulated depreciation	(5,904)	(4,761)
Net other property and equipment	24,006	22,497
Net property and equipment	$ 845,877	$ 591,090

The following table provides a breakdown of the Company's unproved and unevaluated property costs not subject to amortization as of December 31, 2013 and the year in which these costs were incurred (in thousands).

Description	2013	2012	2011	2010 and prior	Total
Costs incurred for					
Property acquisition	$66,582	$22,944	$ 9,050	$77,355	$175,931
Exploration wells	12,901	247	1,932	—	15,080
Development wells	3,145	—	—	—	3,145
Capitalized interest	—	150	—	—	150
Total	$82,628	$23,341	$10,982	$77,355	$194,306

Property acquisition costs primarily include leasehold costs paid to secure oil and natural gas mineral leases, but may also include broker and legal expenses, geological and geophysical expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Property acquisition costs are transferred into the amortization base on an ongoing basis as these properties are evaluated and proved reserves are established or impairment is determined. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions.

Property acquisition costs incurred in 2013 were related primarily to the Company's leasehold acquisitions in the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas, but also include costs associated with additional leasehold acquisitions in the Eagle Ford shale play in South Texas and the Haynesville shale play in Northwest Louisiana and East Texas.

NOTE 3 — PROPERTY AND EQUIPMENT — Continued

Property acquisition costs incurred in 2012 were related primarily to the Company's leasehold acquisitions in 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. Property acquisition costs incurred in 2011 were related primarily to the Company's leasehold acquisitions in the Eagle Ford shale play in South Texas. These costs are associated with acreage for which proved reserves have yet to be assigned. As the Company drills wells and assigns proved reserves to these properties or determines that certain portions of this acreage, if any, cannot be assigned proved reserves, portions of these costs are transferred to the amortization base. The Company estimates that the evaluation of most of these properties and the inclusion of their costs in the amortization base should be completed within three to five years or less.

Property acquisition costs incurred in 2010 and prior years were related primarily to the Company's leasehold acquisitions in the Eagle Ford shale play in South Texas and in the Haynesville shale play in Northwest Louisiana. These costs are associated with acreage for which proved reserves have yet to be assigned. Almost all of these costs are associated with properties which are held by production and have no near-term expiration risk. As the Company drills wells and assigns proved reserves to these properties or determines that certain portions of this acreage, if any, cannot be assigned proved reserves, portions of these costs are transferred to the amortization base. The Company estimates that evaluation of most of these properties and the inclusion of their costs in the amortization base should be completed within three to five years or less.

Costs excluded from amortization also include those costs associated with exploration and development wells in progress or awaiting completion at year-end. These costs are transferred into the amortization base on an ongoing basis as these wells are completed and proved reserves are established or confirmed. These costs totaled $16.0 million for 2013. Of this total, $12.9 million was associated with exploration wells and $3.1 million was associated with development wells. The Company anticipates that the entire $16.0 million associated with these wells in progress at December 31, 2013 will be transferred to the amortization base during 2014. At December 31, 2013, there were $2.2 million in exploratory well costs excluded from amortization that were incurred in years prior to 2013, all associated with the Company's initial exploration well in the Meade Peake shale in Southwest Wyoming. The Company completed the horizontal lateral section of this exploratory well during the fall of 2013, but initial testing was still in progress at December 31, 2013. The Company plans to finalize the testing of this well in 2014 and expects that all exploration costs incurred on this well will be transferred to the amortization base during 2014.

NOTE 4 — ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations for the years ended December 31, 2013 and 2012 (in thousands).

	Year Ended December 31,	
	2013	2012
Beginning asset retirement obligations	$5,769	$4,270
Liabilities incurred during period	936	1,243
Liabilities settled during period	(103)	—
Revisions in estimated cash flows	534	—
Accretion expense	348	256
Ending asset retirement obligations	7,484	5,769
Less: current asset retirement obligations (1)	(175)	(660)
Long-term asset retirement obligations	$7,309	$5,109

(1) Included in accrued liabilities in the Company's consolidated balance sheet at December 31, 2013 and 2012.

NOTE 5 — ASSET SALES AND IMPAIRMENT

In March 2013, the Company recorded an impairment to some of its equipment held in inventory following a determination that the current market value of the equipment, consisting primarily of pipe, was less than the cost. The carrying value was reduced by $192,000 on the consolidated balance sheet, and a corresponding charge was recorded to the consolidated statement of operations for the year ended December 31, 2013.

In December 2012, the Company recorded an impairment to reduce the remaining balance of its drilling rig parts held in inventory to zero following a determination that there was no current market for these parts. The carrying value of the inventory was reduced to zero and a charge of $425,000 was recorded to the consolidated statement of operations. In addition, the Company recorded a loss of approximately $60,000 on certain other equipment that was sold during 2012.

In December 2011, the Company recorded an impairment to some of its equipment held in inventory following a determination that the current market value of the equipment, consisting primarily of drilling rig parts, was less than the cost. The carrying value of the inventory was reduced by $17,500 on the consolidated balance sheet, and a corresponding charge was recorded to the consolidated statement of operations. In December 2011, the Company also recorded an impairment to some of its equipment held in inventory following a determination that the current market value of the equipment, consisting primarily of pipe and other equipment, was less than the cost. The carrying value of the inventory was reduced by $22,276 on the consolidated balance sheet, and a corresponding charge was recorded to the consolidated statement of operations. In addition, the Company recorded a loss of $113,757 on certain other equipment that was sold during 2011.

NOTE 6 — REVOLVING CREDIT AGREEMENT

On September 28, 2012, the Company amended and restated its revolving credit agreement. This third amended and restated credit agreement (the "Credit Agreement") increased the maximum facility amount from $400.0 million to $500.0 million. The Credit Agreement matures December 29, 2016. MRC Energy Company is the borrower under the Credit Agreement. Borrowings are secured by mortgages on substantially all of the Company's oil and natural gas properties 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 the Company's proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both the Company and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the first quarter of 2013, the lenders completed their review of the Company's proved oil and natural gas reserves at December 31, 2012, and on March 11, 2013, the borrowing base was increased from $215.0 million to $255.0 million. In connection with this borrowing base redetermination, the conforming borrowing base was increased to $220.0 million. At that time, the Company also amended the Credit Agreement to include Capital One, N.A., BMO Harris Financing, Inc. (Bank of Montreal) and Iberia Bank in its lending group, which also includes Royal Bank of Canada (RBC), as administrative agent, Comerica Bank, Citibank, N.A., The Bank of Nova Scotia and SunTrust Bank. This March 2013 redetermination constituted the regularly scheduled May 1 redetermination. In late April 2013, the Company requested an unscheduled redetermination of the borrowing base, and on June 4, 2013, the borrowing base was increased from $255.0 million to $280.0 million, and the conforming borrowing base was increased to $245.0 million. On August 7, 2013, the borrowing base under the Credit Agreement was increased to $350.0 million

NOTE 6 — REVOLVING CREDIT AGREEMENT — Continued

and the conforming borrowing base was increased to $275.0 million. At that time, the Company amended the Credit Agreement to provide that the borrowing base would automatically be reduced to the conforming borrowing base at the earlier of (i) June 30, 2014 or (ii) concurrent with the issuance by the Company of senior unsecured notes in an amount greater than or equal to $10.0 million. This August 2013 redetermination constituted the regularly scheduled November 1 redetermination.

During the first quarter of 2014, the lenders completed their review of the Company's estimated total proved oil and natural gas reserves at December 31, 2013, and as a result, on March 12, 2014, the borrowing base under the Credit Agreement was increased to $385.0 million, and the conforming borrowing base was increased to $310.0 million. At that time, Wells Fargo Bank, N.A. replaced Capital One, N.A., in the Company's lending group, and the Company amended the Credit Agreement to 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 the Company 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. In addition, the interest rate charged to the Company based on its outstanding level of borrowings was reduced by 0.25% across the borrowing grid as a result of this amendment to the Credit Agreement. This March 2014 redetermination constituted the regularly scheduled May 1 redetermination. The Company may request one additional unscheduled redetermination of its borrowing base prior to the next scheduled redetermination. The Company expects additional increases to the borrowing base primarily as a result of anticipated increases in its proved oil and natural gas reserves, and particularly its proved developed oil and natural gas reserves.

In the event of a borrowing base increase, the Company is 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, the Company 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.

In connection with the March, June and August 2013 borrowing base redeterminations, the Company incurred $1.1 million of additional deferred loan costs. These costs were included with the remaining unamortized balance of the deferred loan costs incurred previously. As a result, total deferred loan costs were $2.1 million at December 31, 2013, and these costs are being amortized over the term of the Credit Agreement, which approximates amortization of these costs using the effective interest method. The Company incurred an additional $0.8 million of deferred loan costs associated with the March 2014 borrowing base redetermination.

On September 12, 2013, using a portion of the net proceeds from the Company's public equity offering, the Company repaid $130.0 million of its outstanding borrowings under the Credit Agreement. At December 31, 2013, the Company had $200.0 million in borrowings outstanding under the Credit Agreement and approximately $0.3 million in outstanding letters of credit issued pursuant to the Credit Agreement. At December 31, 2013, the Company's outstanding borrowings bore interest at an effective interest rate of approximately 3.3% per annum. From January 1, 2014 through March 13, 2014, the Company borrowed an additional $50.0 million under the Credit Agreement to finance a portion of its working capital requirements and capital expenditures and the acquisition of additional leasehold interests. At March 13, 2014, the Company had $250.0 million in borrowings outstanding under the Credit Agreement and approximately $0.3 million in outstanding letters of credit issued pursuant to the Credit Agreement.

NOTE 6 — REVOLVING CREDIT AGREEMENT — Continued

Under the terms of the Credit Agreement as of December 31, 2013 and until the March 12, 2014 amendment described above, if the Company borrowed funds as a base rate loan, such borrowings bore interest at a rate equal to the higher of (i) the prime rate for such day or (ii) the Federal Funds Effective Rate on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate plus 1.0% plus, in each case, an amount from 0.75% to 3.00% of such outstanding loan depending on the level of borrowings under the agreement. If the Company borrowed funds as a Eurodollar loan, such borrowings bore 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 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 1.75% to 4.00% 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 the Company. A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. The Company includes this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees as interest expense and in its interest rate calculations and related disclosures.

At December 31, 2013, the key financial covenants under the Credit Agreement required the Company to maintain (1) a current ratio, which is defined as consolidated total current assets plus the unused availability under the Credit Agreement divided by consolidated total current liabilities, of 1.0 or greater measured at the end of each fiscal quarter beginning December 31, 2014 and (2) a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.00 or less.

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

- incur indebtedness or grant liens on any of the Company's 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 the Company's 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 the Company or its subsidiaries; and
- a change of control, as defined in the Credit Agreement.

At December 31, 2013, the Company believes that it was in compliance with the terms of its Credit Agreement.

NOTE 7 — INCOME TAXES

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and the tax bases of assets and liabilities. The Company's net deferred tax position as of December 31, 2013 and 2012, respectively, is as follows (in thousands).

	December 31, 2013	December 31, 2012
Current deferred tax assets		
Property and equipment	$ 62	$ 233
Unrealized loss on derivatives	965	—
Other	609	869
Total current deferred tax assets	1,636	1,102
Valuation allowance on current deferred tax assets	—	(202)
Total current deferred tax assets, net of valuation allowance	1,636	900
Current deferred tax liabilities		
Unrealized gain on derivatives	—	(1,311)
Net current deferred tax assets (liabilities)	$ 1,636	$ (411)
Non-current deferred tax assets		
Unrealized loss on derivatives	$ 28	$ —
Net operating loss carryforwards	63,007	44,654
Alternative minimum tax carryforward	7,064	6,660
Total non-current deferred tax assets	70,099	51,314
Valuation allowance on non-current deferred tax assets	(30)	(10,058)
Total non-current deferred tax assets, net of valuation allowance	70,069	41,256
Non-current deferred tax liabilities		
Unrealized gain on derivatives	—	(262)
Property and equipment	(76,719)	(36,363)
Other	(4,279)	(4,220)
Total non-current deferred tax liabilities	(80,998)	(40,845)
Net non-current deferred tax (liabilities) assets	$(10,929)	$ 411

The Company had an effective tax rate of 17.7% for the year ended December 31, 2013. 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 a valuation allowance of approximately $8.9 million on the Company's federal deferred tax assets at December 31, 2012, as the Company's federal deferred tax liabilities exceeded its 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 the Company now believes it 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. The Company reported a net loss for the years ended December 31, 2012 and 2011.

At December 31, 2013, the Company had net operating loss carryforwards of $171.3 million for federal income tax purposes and $3.1 million for state income tax purposes available to offset future taxable income, as limited by the applicable provisions, and which expire at various dates beginning December 31, 2027 for the federal net operating loss carryforwards. The state net operating loss carryforwards began expiring at various dates beginning December 31, 2013 for the state of New Mexico; however, the significant portion of the Company's state net operating loss carryforwards expire beginning in 2027.

At March 31, 2013, the net capitalized costs of the Company's oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $13.7 million. As a result, the Company recorded an impairment charge of $21.2 million to its net capitalized costs and a deferred income tax credit of $7.5 million for the three months ended March 31, 2013. The Company established a valuation allowance at September 30, 2012 and retained full valuation allowances of approximately$15.8 million at March 31, 2013 and $6.7 million at June 30, 2013 due to uncertainties regarding the future realization of the net deferred tax assets.

NOTE 7 — INCOME TAXES — Continued

At June 30, 2012, the net capitalized costs of the Company's oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $21.3 million. As a result, the Company recorded an impairment charge of $33.2 million to the net capitalized costs of its oil and natural gas properties and a deferred income tax credit of $11.9 million. At September 30, 2012, the net capitalized costs of the Company's oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $2.3 million. As a result, the Company recorded an impairment charge of $3.6 million to the net capitalized costs of its oil and natural gas properties and a deferred income tax credit of $1.3 million. This deferred income tax credit exceeded the Company's deferred tax liabilities at September 30, 2012. As a result, the Company established a valuation allowance of $2.4 million at September 30, 2012 due to uncertainties regarding the future realization of its deferred tax assets. At December 31, 2012, the net capitalized costs of the Company's oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling by $17.3 million. As a result, the Company recorded an impairment charge of $26.7 million to the net capitalized costs of its oil and natural gas properties and a deferred income tax credit of $9.4 million. This deferred income tax credit exceeded the Company's deferred tax liabilities at December 31, 2012. As a result, the Company increased the previously established valuation allowance by $7.9 million to maintain a full valuation allowance of $10.3 million against the Company's net deferred tax assets.

At March 31, 2011, the Company recorded an impairment charge of $23.0 million to its net capitalized costs, net of a deferred income tax credit of $12.7 million related to the full-cost ceiling limitation. This deferred income tax credit exceeded the Company's deferred tax liabilities at March 31, 2011. As a result, the Company established a valuation allowance at March 31, 2011 and retained a valuation allowance until the quarter ended December 31, 2011 due to uncertainties regarding the future realization of its deferred tax assets. At December 31, 2011, the Company assessed the valuation allowance and determined that the allowance was no longer required.

The income tax expense reconciled to the tax computed at the statutory federal rate for the years ended December 31, 2013, 2012 and 2011, respectively, is as follows (in thousands).

	Year Ended December 31,		
	2013	2012	2011
Current income tax provision (benefit)			
State income tax	$ —	$ —	$ (46)
Federal alternative minimum tax	404	—	—
Net current income tax provision (benefit)	404	—	(46)
Deferred income tax provision (benefit)			
Federal tax expense at statutory rate (1)	19,177	(11,767)	(5,319)
Statutory depletion carryforward	—	—	231
State income tax	431	(819)	(435)
Nondeductible expense	—	(122)	48
Permanent differences (2)	319	1,018	—
Federal alternative minimum tax	(404)	—	—
Change in federal valuation allowance	(8,885)	10,260	—
Change in state valuation allowance	(1,345)	—	—
Net deferred income tax provision (benefit)	9,293	(1,430)	(5,475)
Total income tax provision (benefit)	$ 9,697	$ (1,430)	$(5,521)

(1) The statutory federal tax rate was 35% for the year ended December 31, 2013 and 34% for the years ended December 31, 2012 and 2011.

(2) Amount is primarily attributable to stock-based compensation.

NOTE 7 — INCOME TAXES — Continued

The Company files a United States federal income tax return and several state tax returns, a number of which remain open for examination. The tax years open for examination for the federal tax return are 2010, 2011, 2012 and 2013. The tax years open for examination by the state of Texas are 2009, 2010, 2011, 2012 and 2013. The tax years open for examination by the state of New Mexico are 2010, 2011, 2012 and 2013. The tax years open for examination by the state of Louisiana are 2010, 2011, 2012 and 2013. As of December 31, 2013, the Company's 2009, 2010, 2011 and 2012 franchise tax returns are under examination by the state of Texas. This examination is in the preliminary stage and no additional income taxes or refunds of previous tax payments for these tax years have been recorded as a result of this examination at December 31, 2013.

The Company has evaluated all tax positions for which the statute of limitations remained open and believes that the material positions taken would more likely than not be sustained by examination. Therefore, at December 31, 2013, the Company had not established any reserves for, nor recorded any unrecognized benefits related to, uncertain tax positions.

NOTE 8 — STOCK-BASED COMPENSATION

Stock Options, Restricted Stock, Restricted Stock Units, Stock and Performance Awards

In 2003 the Company's Board of Directors and shareholders approved the 2003 Plan. The 2003 Plan, as amended, provided that a maximum of 3,481,569 shares of Class A common stock in the aggregate could be issued pursuant to options or restricted stock grants. The persons eligible to receive awards under the 2003 Plan included employees, directors, contractors or advisors of the Company.

Effective January 1, 2012, the Board of Directors adopted the 2012 Incentive Plan. The 2012 Incentive Plan was also approved by the Company's shareholders at its Annual Meeting of Shareholders on June 7, 2012. The 2012 Incentive Plan provides for a maximum of 4,000,000 shares of common stock in the aggregate that may be issued by the Company pursuant to grants of stock options, restricted stock, stock appreciation rights, restricted stock units or other performance awards. The persons eligible to receive awards under the 2012 Incentive Plan include employees, directors, contractors or advisors of the Company. The primary purpose of the 2012 Incentive Plan is to attract and retain key employees, key contractors and outside directors and advisors of the Company. With the adoption of the 2012 Incentive Plan, the Company does not plan to make any future awards under the 2003 Plan, but the 2003 Plan will remain in place until all awards outstanding under that plan have been settled.

The 2003 Plan and the 2012 Incentive Plan are administered by the independent members of the Board of Directors, which determines the number of options or restricted shares to be granted, the effective dates, the terms of the grants and the vesting periods. The Company typically uses newly issued shares of common stock to satisfy option exercises or restricted share grants. All stock-based compensation awards granted during 2013 and 2012 were granted under the 2012 Incentive Plan and are equity-based awards for which the fair value is fixed at the grant date, while all stock-based compensation awards granted prior to January 1, 2012 were granted under the 2003 Plan and are liability-based awards for which the fair value is remeasured at every reporting period.

Stock Options

Historically, stock option awards have been granted to purchase the Company's common stock at an exercise price equal to the fair market value on the date of grant, a typical vesting period of three or four years and a typical maximum term of five or ten years.

NOTE 8 — STOCK-BASED COMPENSATION — Continued

Effective upon filing its initial Registration Statement with the SEC in August 2011, the Company adopted the fair value method and used an estimated fair value of $12.00 per share to measure and recognize the liability associated with its outstanding stock options. The Company recorded $1.1 million in additional general and administrative expenses during 2011 due to this change in the valuation method from the intrinsic value method to the fair value method.

The Company granted no stock option awards during the year ended December 31, 2011. The fair value of stock option awards outstanding under the 2003 Plan was estimated using the following weighted average assumptions at December 31, 2013, 2012 and 2011.

	2013	2012	2011
Stock option pricing model	Black Scholes Merton	Black Scholes Merton	Black Scholes Merton
Expected option life	2.44 years	0.89 years	1.04 years
Risk-free interest rate	0.69%	0.25%	0.37%
Volatility	51.51%	54.28%	61.41%
Dividend yield	—%	—%	—%
Estimated forfeiture rate	0.79%	0.70%	1.04%

The weighted average grant date fair value for stock option awards outstanding under the 2012 Incentive Plan was estimated using the following weighted average assumptions during the years ended December 31, 2013 and 2012.

	2013	2012
Stock option pricing model	Black Scholes Merton	Black Scholes Merton
Expected option life	4.0 years	4.4 years
Risk-free interest rate	0.69%	0.71%
Volatility	58.65%	71.16%
Dividend yield	—%	—%
Estimated forfeiture rate	6.37%	5.46%
Weighted average fair value of stock option awards granted during the year	$ 3.91	$ 5.95

The Company estimated the future volatility of its common stock using the historical value of its peer group for a period of time commensurate with the expected term of the stock option due to the lack of historical trading data available for its common stock. The expected term was estimated using the simplified method outlined in Staff Accounting Bulletin Topic 14. 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.

Summarized information about stock options outstanding at December 31, 2013 under the Company's 2003 Plan and the 2012 Incentive Plan is as follows (in thousands, except price data).

	Number of options	Weighted average exercise price
Options outstanding at December 31, 2012	1,067	$10.19
Options granted	874	8.78
Options exercised	(5)	7.77
Options forfeited	(59)	9.86
Options expired	(449)	10.30
Options outstanding at December 31, 2013	1,428	$ 9.32

NOTE 8 — STOCK-BASED COMPENSATION — Continued

Range of Exercise Prices	Options outstanding at December 31, 2013 Shares outstanding	Weighted average remaining contractual life	Weighted average exercise price	Options exercisable at December 31, 2013 Shares exercisable	Weighted average exercise price
$7.50 - $10.00	938	4.30 years	$ 8.33	79	$ 8.90
$10.39 - $13.03	451	3.50 years	$10.56	15	$11.00
$17.80 - $19.05	39	4.89 years	$18.73	—	$ —

At December 31, 2013, the aggregate intrinsic value was $13.3 million for outstanding options and $0.9 million for exercisable options, based on the Company's quoted closing market price of $18.64 per share on that date. The remaining weighted average contractual term of exercisable options at December 31, 2013 was 5.97 years.

The total intrinsic value of options exercised during the years ended December 31, 2013, 2012 and 2011 was $36,000, $0.9 million and $0.2 million, respectively. The tax related benefit realized from the exercise of stock options totaled zero, zero and zero for the years ended December 31, 2013, 2012 and 2011, respectively.

During the years ended December 31, 2013, 2012 and 2011, the Company recognized $2.2 million, $(0.7) million and $2.1 million, respectively, in stock-based compensation expense attributable to stock options. At December 31, 2013, 2012 and 2011, the Company had recorded $1.2 million, $0.3 million and $0.3 million of long-term liabilities and $0.1 million, $0.1 million and $2.9 million of current liabilities, respectively, related to its outstanding liability-based stock options. The Company paid zero, zero and $0.1 million in settlement of liability-based awards for the years ended December 31, 2013, 2012 and 2011, respectively.

At December 31, 2013, the total remaining unrecognized compensation expense related to unvested stock options was approximately $4.1 million and the weighted average remaining requisite service period (vesting period) of all unvested stock options was 1.90 years.

The fair value of options vested during 2013, 2012 and 2011 was $0.3 million, $0.3 million and $1.0 million, respectively.

Restricted Stock, Restricted Stock Units and Common Stock

The Company has granted stock, restricted stock and restricted stock unit awards to employees, outside directors and advisors of the Company under the 2003 Plan and the 2012 Incentive Plan. The stock and restricted stock are issued upon grant, with the restrictions being removed upon vesting. The restricted stock units are issued upon vesting, unless the recipient makes an election to defer issuance for a term no longer than two years after vesting. No such elections were made with respect to the 2012 restricted stock unit awards; two directors elected to defer the issuance of their awards in 2013. All awards granted in 2013 were service based awards and vest over the service period which is one to four years. All restricted stock and restricted stock unit awards outstanding at December 31, 2013 were granted under the 2012 Incentive Plan.

The 2012 restricted stock awards included 116,841 shares of performance based restricted stock and 116,841 performance based restricted stock units with a combined weighted average fair value of $13.24 per combined share and unit. These awards vest based on the outcome of the Company's total shareholder return over a three-year period beginning March 19, 2012 and ending April 15, 2015 as compared to a designated peer group. These awards may result in the vesting of an aggregate of up to 116,841 restricted stock units in addition to the 116,841 shares of restricted stock. If the performance conditions are not met, however, these awards may result in no performance based restricted stock vesting and no restricted stock units vesting. The fair value of these

NOTE 8 — STOCK-BASED COMPENSATION — Continued

awards was estimated based on the most likely outcome of the award as determined by the Monte Carlo method. A total of 206,842 service based restricted stock awards were granted during the year ended December 31, 2012, with a weighted average fair value of $9.66 per share. Of these awards, 13,833 shares of restricted stock vested immediately upon grant, and the remaining restricted stock vests over the service period, which ranges from one year to a maximum of four years. A total of 54,166 service based restricted stock unit awards were granted during the year ended December 31, 2012, with a weighted average fair value of $10.04 per unit. No restricted stock awards or restricted stock unit awards were granted during the year ended December 31, 2011.

A summary of the non-vested restricted stock and restricted stock units as of December 31, 2013 is presented below (in thousands, except fair value).

	Restricted Stock				Restricted Stock Units			
	Service Based		Performance Based		Service Based		Performance Based	
Non-vested Restricted Stock and Restricted Stock Units	Shares	Weighted average fair value	Shares	Weighted average fair value(1)	Shares	Weighted average fair value	Shares	Weighted average fair value(1)
Non-vested at December 31, 2012	182	$9.72	110	$13.24	52	$10.00	110	$ —
Granted	378	9.07	—	—	51	11.31	—	—
Vested	(1)	8.43	—	—	(17)	10.00	—	—
Forfeited	(95)	8.57	(10)	13.24	—	—	(10)	—
Non-vested at December 31, 2013	464	$9.43	100	$13.24	86	$10.79	100	$ —

(1) The fair value of these restricted stock units is reflected in the fair value of the performance based restricted stock, which was estimated based on the most likely outcome of the award as determined by the Monte Carlo method.

At December 31, 2013, the aggregate intrinsic value for the restricted stock and restricted stock units outstanding was $14.0 million as calculated based on the maximum number of shares of restricted stock, performance based restricted stock and restricted stock units vesting, using the stock price on December 31, 2013.

During the years ended December 31, 2013, 2012 and 2011, the Company recognized approximately $1.6 million, $0.7 million and $44,000, respectively, in stock-based compensation expense attributable to restricted stock and restricted stock units.

At December 31, 2013, the total remaining unrecognized compensation expense related to unvested restricted stock and restricted stock units was approximately $4.6 million and the weighted average remaining requisite service period (vesting period) of all non-vested restricted stock and restricted stock units was 1.82 years.

The fair value of restricted stock and restricted stock units vested during 2013, 2012 and 2011 was $182,000, $44,000 and $44,000, respectively.

The total tax benefit recognized for all stock-based compensation was $1.1 million, $0.3 million and $0.9 million for the years ended December 31, 2013, 2012 and 2011, respectively.

During the years ended December 31, 2013, 2012 and 2011, the Company issued shares of common stock to certain members of its Board of Directors. The Company also issued shares of common stock to certain outside advisors who do not meet the definition of employees under ASC 718. The Company used the fair value of the stock issued on the grant date to recognize the expense related to these awards. The Company recognized $0.1 million, $0.1 million and $0.2 million in stock-based compensation expense attributable to these awards for the years ended December 31, 2013, 2012 and 2011, respectively.

NOTE 8 — STOCK-BASED COMPENSATION — Continued

In October 2008, the Company's Board of Directors approved the adoption of the Employee Option Exercise Loan Program ("Loan Program"), authorizing the Company to establish a loan program with a financial institution to assist its employees, directors and officers in the exercise of their outstanding options to purchase shares of Class A common stock, subject to certain conditions and restrictions outlined in the Loan Program. As part of the Loan Program, the Company provided the financial institution with a guaranty of repayment of the loan and made deposits of funds in certificates of deposit to secure its guaranty. Notwithstanding the guaranty, these loans were fully recourse obligations of each loan recipient, and each loan recipient agreed to indemnify and reimburse the Company in full for all liabilities incurred by the Company in the event of the recipient's default on the loan. Each loan recipient also pledged all shares purchased from the Company with the loan proceeds to further secure his or her obligations to the Company in return for its guaranty. No director nor the Company's Chairman and Chief Executive Officer participated in the Loan Program.

As of December 31, 2013 all of these loans had been repaid. As of December 31, 2012, the Company had secured the loans of four employees pursuant to this Loan Program in the aggregate amount of $0.2 million. The Company considered the fair value of this aggregate guaranty to be minimal and recorded no liability provision associated with this guaranty on its consolidated balance sheet in any reporting period presented. The Company's Board of Directors terminated the Loan Program in April 2011, and the Company is no longer authorized to provide financial guaranties for additional loans. No new loans were guaranteed in 2011 prior to the termination of the Loan Program by the Board of Directors.

NOTE 9 — EMPLOYEE BENEFIT PLANS

401(k) Plan

Effective July 3, 2003, the Company established a defined contribution retirement plan. All full-time Company employees are eligible to join the plan the first day of the calendar month immediately following their date of employment. Each Participant may contribute up to the maximum allowable under the Internal Revenue Code. Each year, the Company makes a contribution to the plan which equals 3% of the employee's annual compensation, referred to as the Employer's Safe Harbor Non-Elective Contribution. The Company's Safe Harbor match was approximately $0.2 million in each of 2013, 2012 and 2011. In addition, each year, the Company may make a discretionary matching contribution as well as additional contributions. The Company's discretionary matching contributions totaled $0.3 million, $0.3 million and $0.2 million in 2013, 2012 and 2011, respectively. The Company made no additional discretionary contributions in any reporting period presented.

NOTE 10 — COMMON STOCK

Dividends

At December 31, 2011, the Company had issued two classes of common stock, Class A and Class B. In February 2012, upon the consummation of the Company's Initial Public Offering, the Class B shares were converted to Class A shares, which are now referred to as common stock. The holders of the Class B shares were entitled to be paid cumulative dividends at a per share rate of $0.26-2/3 annually out of funds legally available for the payment of dividends. These dividends were accrued and paid quarterly. Dividends declared and paid during 2012 were $27,643. Dividends declared during 2011 totaled $0.3 million. Dividends for the fourth quarter of 2011 were accrued and paid in January 2012. Dividends for the fourth quarter of 2010 were accrued and paid in

NOTE 10 — COMMON STOCK — Continued

January 2011. As of December 31, 2013, the Company has not paid any dividends to holders of the Class A shares. In addition, certain covenants in the Company's Credit Agreement may limit the Company's ability to pay dividends on its common stock.

Stock Offerings, Retirement and Issuances

In April 2013, the Company filed with the SEC a universal shelf registration statement on Form S-3 (the "Shelf Registration Statement"), which provides the Company with the ability to offer and sell up to $300.0 million of debt and equity securities, subject to market conditions and its capital needs. The SEC declared the Shelf Registration Statement effective on May 9, 2013. As of December 31, 2013, the Company had approximately $151.0 million of securities available for issuance under the Shelf Registration Statement.

On September 10, 2013, the Company completed an underwritten public offering of 9,775,000 shares of its 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, the Company received net proceeds of approximately $141.7 million. The Company is using the net proceeds from this offering primarily to fund a portion of its capital expenditures, including for the addition of the third rig to its drilling program. The Company is also using the net proceeds from this offering to fund the acquisition of additional acreage in the Permian Basin, the Eagle Ford shale and the Haynesville shale. Pending such uses, the Company used a portion of the net proceeds to repay $130.0 million in outstanding borrowings under its Credit Agreement (see Note 6) in September 2013, which amounts may be reborrowed in accordance with the terms of that facility for, among other items, the uses contemplated above. The remaining $11.7 million of the offering net proceeds was used to fund working capital requirements.

On August 12, 2011, the Company filed a Form S-1 Registration Statement under the Securities Act of 1933 to commence the Initial Public Offering. The Company's Registration Statement (File 333-176263), as amended, was declared effective by the SEC on February 1, 2012. The underwriters for the Company's Initial Public Offering were RBC Capital Markets, LLC; Citigroup Global Markets, Inc.; Jefferies & Company, Inc.; Howard Weil Incorporated; Stifel, Nicolaus & Company, Incorporated; Simmons & Company International; Stephens Inc. and Comerica Securities, Inc.

On February 2, 2012, shares of the Company's common stock began trading on the New York Stock Exchange under the symbol "MTDR" at an initial offering price of $12.00 per share.

Pursuant to its prospectus dated February 1, 2012, the Company offered 11,666,667 shares of its common stock for sale, and the selling shareholders offered 1,550,000 shares for sale. On February 7, 2012, the Company closed the Initial Public Offering and issued 11,666,667 shares of its common stock pursuant to the Initial Public Offering.

The Company and the selling shareholders granted the underwriters the right to purchase up to an additional 2,000,000 shares of the Company's common stock at the initial offering price of $12.00 per share, less the underwriters' discounts and commissions, for a period of 30 days following the Initial Public Offering to cover over-allotments, with the Company offering 700,000 shares and the selling shareholders offering 1,300,000 shares. On March 2, 2012, the underwriters exercised their option to purchase an additional 1,550,000 shares, including the purchase of 542,500 shares from the Company and the purchase of 1,007,500 shares from the selling shareholders. On March 7, 2012, the Company closed this transaction and issued 542,500 shares of its common stock pursuant to the underwriters' exercise of the over-allotment.

NOTE 10 — COMMON STOCK — Continued

Pursuant to the Initial Public Offering and the over-allotment, the Company issued a total of 12,209,167 shares of its common stock at $12.00 per share and received estimated net proceeds of approximately $133.6 million after deducting the underwriters' discounts and commissions and the estimated legal, accounting and other fees associated with the offering. The Company did not receive any proceeds from the sale of shares of its common stock by the selling shareholders. On February 8, 2012, the Company used the net proceeds of the offering to repay the $123.0 million in borrowings then outstanding under its Credit Agreement in full. The Company used the remaining net proceeds of the offering to fund a portion of its 2012 capital expenditures.

Concurrent with the completion of the Initial Public Offering, all 1,030,700 outstanding shares of the Company's Class B common stock were converted to Class A common stock on a one-for-one basis. In addition, in February 2012, the Company issued an additional 295,500 shares of its Class A common stock pursuant to the exercise of stock options and received net proceeds of $2.7 million. The Class A common stock is now referred to as the common stock.

In October 2010, the Board of Directors approved and authorized the private offering and sale of additional shares of the Company's Class A common stock at $11.00 per share in the period from October 2010 through January 2011. As of December 31, 2010, the Company sold approximately 1.9 million shares and received net proceeds of $20.5 million. In January 2011, the Company sold an additional 53,772 shares as part of this offering and received net proceeds of approximately $0.6 million.

Treasury Stock

The increase of 105,126 and 21,876 shares in treasury stock outstanding during 2013 and 2012, respectively, represents forfeitures of non-vested restricted stock awards.

NOTE 11 — DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its 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 collars and swap contracts. The Company records derivative financial instruments on its consolidated balance sheet as either assets or liabilities measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments. As a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statement of operations as an unrealized gain or loss. The fair value of the Company's derivative financial instruments is determined using purchase and sale information available for similarly traded securities. Comerica Bank, RBC, The Bank of Nova Scotia and SunTrust Bank (or affiliates thereof) were the counterparties for the Company's commodity derivatives at December 31, 2013. The Company has considered the credit standings of the counterparties in determining the fair value of its derivative financial instruments.

The Company has entered into various costless collar contracts to mitigate its 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 pursuant to any of these 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, the Company receives from the 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, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil volume.

NOTE 11 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The Company has entered into various swap contracts to mitigate its exposure to fluctuations in oil prices, each with an established fixed price. For each calculation period, the specified price for determining the realized gain or loss pursuant to any of these transactions was 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 was below the fixed price established by one or more of these swaps, the Company received from the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume. When the settlement price was above the fixed price established by one or more of these swaps, the Company paid to the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract oil volume. These oil price swap contracts expired on December 31, 2013.

The Company has entered into various costless collar transactions for natural gas, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to the Company 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, the Company receives from the 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, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract natural gas volume.

The Company has entered into various swap contracts to mitigate its exposure to fluctuations in natural gas liquids ("NGL") prices, each with an established fixed price. For each calculation period, the settlement price for determining the realized gain or loss to the Company 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 as stated on the "Mont Belvieu Spot Gas Liquids Prices: NON-TET prop" on the pricing date. When the settlement price is below the fixed price established by one or more of these swaps, the Company receives from the 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, the Company pays to the counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the contract NGL volume.

At December 31, 2013, the Company had various costless collar contracts open and in place to mitigate its exposure to oil and natural gas price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and price floor and ceiling. Each contract is set to expire at varying times during 2014 and 2015.

At December 31, 2013, the Company had various swap contracts open and in place to mitigate its exposure to NGL price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and fixed price. Each contract is set to expire at varying times during 2014 and 2015.

NOTE 11 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following is a summary of the Company's open costless collar contracts for oil and natural gas and open swap contracts for NGL at December 31, 2013.

Commodity	Calculation Period	Notional Quantity (Bbl/month)	Price Floor ($/Bbl)	Price Ceiling ($/Bbl)	Fair Value of Asset (Liability) (thousands)
Oil	01/01/2014 - 06/30/2014	8,000	$90.00	$114.00	$ 44
Oil	01/01/2014 - 06/30/2014	12,000	90.00	115.50	67
Oil	01/01/2014 - 12/31/2014	15,000	85.00	97.50	(309)
Oil	01/01/2014 - 12/31/2014	30,000	85.00	98.00	(560)
Oil	01/01/2014 - 12/31/2014	12,000	85.00	100.00	(90)
Oil	01/01/2014 - 12/31/2014	12,200	85.00	100.40	(70)
Oil	01/01/2014 - 12/31/2014	10,000	85.00	100.55	(52)
Oil	01/01/2014 - 12/31/2014	15,000	87.00	97.00	(294)
Oil	01/01/2014 - 12/31/2014	20,000	88.00	95.60	(536)
Oil	01/01/2014 - 12/31/2014	20,000	90.00	97.00	(253)
Oil	01/01/2014 - 12/31/2014	12,000	90.00	97.90	(80)
Oil	01/01/2014 - 12/31/2014	15,000	90.00	97.90	(98)
Oil	01/01/2014 - 12/31/2014	15,000	90.00	98.00	(101)
Oil	01/01/2014 - 12/31/2014	15,000	90.00	101.15	132
Total open oil costless collar contracts					(2,200)

Commodity	Calculation Period	Notional Quantity (MMBtu/month)	Price Floor ($/MMBtu)	Price Ceiling ($/MMBtu)	Fair Value of Asset (Liability) (thousands)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.00	5.15	(60)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.21	(34)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.22	(34)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.37	(22)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.25	5.42	(18)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.50	4.90	(37)
Natural Gas	01/01/2014 - 12/31/2014	100,000	3.75	4.77	3
Natural Gas	01/01/2014 - 12/31/2015	100,000	3.75	4.36	(237)
Natural Gas	01/01/2014 - 12/31/2015	100,000	3.75	4.45	(158)
Natural Gas	01/01/2014 - 12/31/2015	100,000	3.75	4.60	(24)
Natural Gas	04/01/2014 - 12/31/2014	100,000	3.75	4.75	6
Natural Gas	01/01/2015 - 03/31/2015	200,000	4.00	4.84	(3)
Natural Gas	01/01/2015 - 12/31/2015	100,000	3.75	4.65	(9)
Natural Gas	01/01/2015 - 12/31/2015	200,000	3.75	5.04	182
Total open natural gas costless collar contracts					(445)

NOTE 11 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

Commodity	Calculation Period	Notional Quantity (Gal/month)	Fixed Price ($/Gal)	Fair Value of Asset (Liability) (thousands)
Propane	01/01/2014 - 12/31/2014	116,000	0.950	(247)
Propane	01/01/2014 - 12/31/2014	84,000	1.143	32
Propane	01/01/2014 - 12/31/2014	68,000	1.150	32
Propane	01/01/2014 - 12/31/2014	116,000	1.003	(150)
Propane	01/01/2014 - 12/31/2014	60,000	1.015	(69)
Propane	01/01/2015 - 12/31/2015	150,000	1.000	(58)
Propane	01/01/2015 - 12/31/2015	68,000	1.073	33
Normal Butane	01/01/2014 - 12/31/2014	17,500	1.540	47
Normal Butane	01/01/2014 - 12/31/2014	45,500	1.550	122
Isobutane	01/01/2014 - 12/31/2014	22,000	1.640	78
Isobutane	01/01/2014 - 12/31/2014	37,000	1.640	140
Natural Gasoline	01/01/2014 - 12/31/2014	30,000	1.970	(35)
Natural Gasoline	01/01/2014 - 12/31/2014	41,000	2.000	(33)
Total open NGL swap contracts				(108)
Total open derivative financial instruments				$(2,753)

These derivative financial instruments are subject to master netting arrangements within specific commodity types, i.e., oil, natural gas and NGL, by counterparty. Derivative financial instruments with Counterparty A are not subject to master netting across commodity types, while derivative financial instruments with Counterparties B, C and D allow for cross-commodity master netting provided the settlement dates for the commodities are the same. The Company does not present different types of commodities with the same counterparty on a net basis in its consolidated balance sheet.

The following table presents the gross asset balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its consolidated balance sheet as of December 31, 2013 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the consolidated balance sheet	Net amounts of assets presented in the consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$1,746	$(1,746)	$ —	$ —
Other assets	—	—	—	—
Counterparty B				
Current assets	1,371	(1,371)	—	—
Other assets	841	(668)	173	—
Counterparty C				
Current assets	2,886	(2,873)	13	—
Other assets	1,046	(1,046)	—	—
Counterparty D				
Current assets	6	—	6	—
Other assets	—	—	—	—
Total	$7,896	$(7,704)	$192	$ —

NOTE 11 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following table presents the gross liability balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis, amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its consolidated balance sheet as of December 31, 2013 (in thousands).

Derivative Instruments	Gross amounts of recognized liabilities	Gross amounts netted in the consolidated balance sheet	Net amounts of liabilities presented in the consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current liabilities	$ 2,550	$(1,746)	$ 804	$ —
Long-term liabilities	—	—	—	—
Counterparty B				
Current liabilities	2,136	(1,371)	765	—
Long-term liabilities	668	(668)	—	—
Counterparty C				
Current liabilities	3,996	(2,873)	1,123	—
Long-term liabilities	1,299	(1,046)	253	—
Counterparty D				
Current liabilities	—	—	—	—
Long-term liabilities	—	—	—	—
Total	$10,649	$(7,704)	$2,945	$ —

The following table presents the gross asset balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its consolidated balance sheet as of December 31, 2012 (in thousands).

Derivative Instruments	Gross amounts of recognized assets	Gross amounts netted in the consolidated balance sheet	Net amounts of assets presented in the consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current assets	$6,445	$(2,373)	$4,072	$ —
Other assets	1,096	(370)	726	—
Counterparty B				
Current assets	530	(224)	306	82
Other assets	384	(339)	45	—
Total	$8,455	$(3,306)	$5,149	$ 82

NOTE 11 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following table presents the gross liability balances of the Company's derivative financial instruments, the amounts subject to master netting arrangements, the amounts that the Company has presented on a net basis, the amounts subject to master netting across different commodity types that were presented on a gross basis and the location of these balances in its consolidated balance sheet as of December 31, 2012 (in thousands).

Derivative Instruments	Gross amounts of recognized liabilities	Gross amounts netted in the consolidated balance sheet	Net amounts of liabilities presented in the consolidated balance sheet	Amounts subject to master netting arrangements presented on a gross basis
Counterparty A				
Current liabilities	$2,373	$(2,373)	$ —	$ —
Long-term liabilities	370	(370)	—	—
Counterparty B				
Current liabilities	894	(224)	670	82
Long-term liabilities	339	(339)	—	—
Total	$3,976	$(3,306)	$670	$82

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the consolidated statements of operations for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Statement of Operations	Year Ended December 31, 2013	2012	2011
Derivative Instrument				
Oil	Revenues: Realized (loss) gain on derivatives	$(2,408)	$ 2,047	$ —
Natural Gas	Revenues: Realized gain on derivatives	831	11,892	7,106
NGL	Revenues: Realized gain on derivatives	668	21	—
Realized (loss) gain on derivatives		(909)	13,960	7,106
Oil	Revenues: Unrealized (loss) gain on derivatives	(5,319)	3,673	(554)
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(1,580)	(8,700)	5,692
NGL	Revenues: Unrealized (loss) gain on derivatives	(333)	225	—
Unrealized (loss) gain on derivatives		(7,232)	(4,802)	5,138
Total		$(8,141)	$ 9,158	$12,244

NOTE 12 — FAIR VALUE MEASUREMENTS

The Company measures and reports certain financial and non-financial assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements are classified and disclosed in one of the following categories.

Level 1 Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that are valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3 Unobservable inputs that are not corroborated by market data. This category is comprised of financial and non-financial assets and liabilities whose fair value is estimated based on internally developed models or methodologies using significant inputs that are generally less readily observable from objective sources.

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

At December 31, 2013 and 2012, the carrying values reported on the consolidated balance sheets for accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, advances from joint interest owners, income taxes payable and other current liabilities approximate their fair values due to their short-term maturities and are classified at Level 1.

At December 31, 2013 and 2012, the carrying value of borrowings under the Credit Agreement approximates fair value as it is subject to short-term floating interest rates that reflect market rates available to the Company at the time and is classified at Level 2.

The following tables summarize the valuation of the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of December 31, 2013 and 2012 (in thousands).

	Fair Value Measurements at December 31, 2013 using			
Description	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil, natural gas and NGL derivatives	$ —	$ 192	$ —	$ 192
Oil, natural gas and NGL derivatives	—	(2,945)	—	(2,945)
Total	$ —	$(2,753)	$ —	$(2,753)

NOTE 12 — FAIR VALUE MEASUREMENTS — Continued

Description	Fair Value Measurements at December 31, 2012 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Certificates of deposit	$ —	$ 230	$ —	$ 230
Oil, natural gas and NGL derivatives	—	5,149	—	5,149
Oil, natural gas and NGL derivatives	—	(670)	—	(670)
Total	$ —	$4,709	$ —	$4,709

The Company's accounting policies for certificates of deposit and derivative financial instruments are discussed in Note 2; additional disclosures related to derivative financial instruments are provided in Note 11. For purposes of fair value measurement, the Company determined that certificates of deposit and derivative financial instruments (e.g., oil, natural gas and NGL derivatives) should be classified at Level 2.

The Company accounts for additions to asset retirement obligations and lease and well equipment inventory when adjusted for impairment at fair value on a non-recurring basis. The following tables summarize the valuation of the Company's assets and liabilities that were accounted for at fair value on a non-recurring basis as of December 31, 2013 and 2012 (in thousands).

Description	Fair Value Measurements at December 31, 2013 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$ —	$ —	$(1,470)	$(1,470)
Total	$ —	$ —	$(1,470)	$(1,470)

Description	Fair Value Measurements at December 31, 2012 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Asset retirement obligations	$ —	$ —	$(1,243)	$(1,243)
Lease and well equipment inventory	—	—	34	34
Total	$ —	$ —	$(1,209)	$(1,209)

The Company's accounting policies for asset retirement obligations are discussed in Note 2; reconciliations of the Company's asset retirement obligations are provided in Note 4 for the periods presented. For purposes of fair value measurement, the Company determined that the additions to asset retirement obligations should be classified at Level 3. The Company recorded additions to asset retirement obligations of approximately $1.5 million and $1.2 million in 2013 and 2012, respectively.

The Company's accounting policies for lease and well equipment inventory are discussed in Note 2. For purposes of fair value measurement, the Company determined that lease and well equipment inventory should be classified at Level 3. The Company recorded an impairment of $192,000 to its equipment, consisting primarily of pipe, held in inventory in 2013. The Company recorded an impairment to some of its equipment held in inventory, consisting primarily of drilling rig parts and pipe, of $425,000 and $60,464, respectively, in 2012. The Company periodically obtains estimates of the market value of its equipment held in inventory from an independent third-party contractor or seller of similar equipment and uses these estimates as a basis for its measurement of the fair value of this equipment.

NOTE 13 — COMMITMENTS AND CONTINGENCIES

Office Lease

The Company's corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. In April 2013, the Company entered into the fifth amendment to its office lease agreement. This amendment increased the square footage of its corporate headquarters to 40,071 square feet effective July 1, 2013. The lease expires on June 30, 2022.

The effective base rent over the term of the new lease extension is $20.28 per square foot per year. The base rate escalates several times during the course of the lease, specifically in July 2015, July 2017, July 2019 and July 2020; however, the Company recognizes rent expense under the lease ratably over the term of the lease.

The following is a schedule of future minimum lease payments required under the office lease agreement as of December 31, 2013 (in thousands).

Year Ending December 31,	Amount
2014	$ 812
2015	831
2016	852
2017	872
2018	893
Thereafter	3,329
Total	$7,589

Rent expense, including fees for operating expenses and consumption of electricity, was $0.8 million, $0.6 million and $0.5 million for 2013, 2012 and 2011, respectively.

Natural Gas and NGL Processing and Transportation Commitments

Effective September 1, 2012, the Company entered into a firm five-year natural gas processing and transportation agreement whereby the Company committed to transport the anticipated natural gas production from a significant portion of its 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 the Company receives varies with the quality of natural gas transported to the processing facilities and the contract period.

Under this agreement, if the Company does not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, it 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 periods, the Company had an immaterial natural gas deficiency, and the counterparty to this agreement has agreed to waive the deficiency fee. The Company paid approximately $5.3 million and $0.3 million in processing and transportation fees under this agreement during the years ended December 31, 2013 and 2012, respectively.

NOTE 13 — COMMITMENTS AND CONTINGENCIES — Continued

The aggregate undiscounted minimum commitments under this agreement at December 31, 2013 are as follows (in thousands).

Year Ending December 31,	Amount
2014	$ 4,731
2015	2,992
2016	1,800
2017	1,195
Total	$10,718

Other Commitments

From time to time, the Company enters into contracts with third parties for drilling rigs. These contracts establish daily rates for the drilling rigs and the term of the Company's commitment for the drilling services to be provided, which are typically for one year or less. Should the Company elect to terminate a contract and if the drilling contractor were unable to secure 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 the Company prior to the end of their respective contract terms, the Company would incur termination obligations. The Company's maximum outstanding aggregate termination obligations under its drilling rig contracts were approximately $9.9 million at December 31, 2013.

At December 31, 2013, the Company had outstanding commitments to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed as proposed, the Company's minimum outstanding aggregate commitments for its participation in these non-operated wells were approximately $5.7 million at December 31, 2013. The Company expects these costs to be incurred within the next few months.

Legal Proceedings

Cynthia Fry Peironnet, et al. v. Matador Resources Company. The Company was involved in a dispute over a mineral rights lease (the "Lease") involving certain acreage in Louisiana. The dispute regarded an extension of the term of the Lease in Caddo Parish, Louisiana where the Company has drilled or participated in the drilling of both Cotton Valley and Haynesville shale wells. At issue were the deep rights below the Cotton Valley formation on approximately 1,805 gross acres where the Company has the right to participate for up to a 25% working interest, and also retains a small overriding royalty interest, in Haynesville shale wells drilled in units that include portions of the acreage. The Company's total net revenue and overriding royalty interests in several non-operated Haynesville shale wells previously drilled on this acreage range from approximately 2% to 23%, and only portions of these interests are attributable to this acreage. The sum of the Company's overriding royalty and net revenue interests attributable to this acreage from Haynesville wells previously drilled on this acreage comprises less than one net well.

The plaintiffs brought this claim against the Company on May 15, 2008 in the First Judicial District Court, Caddo Parish, Louisiana (the "Trial Court"). The plaintiffs sought (i) reformation or rescission of the lease extension, (ii) an accounting for additional royalty, (iii) monetary damages and (iv) attorney's fees. During the pendency of the case in the Trial Court, the Company settled with one lessor who owned a $1/6^{th}$ undivided interest in the minerals. The Trial Court rendered multiple rulings in the favor of the Company, including a unanimous jury verdict in favor of the Company in the fall of 2010. Final judgment of the Trial Court was rendered in favor of the Company on June 6, 2011. On August 1, 2012, the Louisiana Second Circuit of Appeal (the "Court of Appeal") affirmed in part and reversed in part the judgment of the Trial Court and remanded the case to the Trial Court for determination of damages. The Court of Appeal affirmed the Trial Court with respect to the $1/6^{th}$ royalty owner that settled and also affirmed that the Company's lease extension was unambiguous. Nonetheless, the Court of Appeal reformed the

NOTE 13 — COMMITMENTS AND CONTINGENCIES — Continued

lease extension to cover only approximately 169 gross acres, holding that the deep rights covering the remaining 1,636 gross acres had expired. The Court of Appeal denied the Company's motion for rehearing, and the Company and certain other defendants filed an appeal with the Louisiana Supreme Court. The Louisiana Supreme Court granted the requests to hear an appeal of the Court of Appeal's decision, and in June 2013, the Louisiana Supreme Court reversed the decision of the Court of Appeal and reinstated the Trial Court judgment in its entirety. The plaintiffs filed an application for rehearing with the Louisiana Supreme Court, which was denied on August 30, 2013.

MRC Energy Company f/k/a Matador Resources Company, v. Orca ICI Development, J.V. The Company and Orca, a non-operator working interest owner, had various disputes regarding certain of the Company's Eagle Ford shale wells and properties. Among other things, issues arose with respect to the rights and obligations of the Company and Orca under various agreements between the parties and Orca sought the Company's consent to Orca's proposed assignment of its 50% working interest in the Cowey #3H and #4H wells to a non-industry person, despite the presence of a uniform maintenance of interest provision. On April 2, 2013, Orca brought suit against the Company in the 57th Judicial District Court of Bexar County, Texas and sought injunctive relief. The court denied Orca's demand for injunctive relief and on April 5, 2013, the Company moved to enforce arbitration provisions in the agreements between the parties. On April 22, 2013, the Company initiated an arbitration against Orca, seeking, among other things, a declaration that the Company could withhold its consent to Orca's putative assignment of these interests. On May 6, 2013, Orca and the Company agreed to resolve all outstanding issues between the parties regarding the respective rights and obligations of the parties under the agreements between them. In addition, Matador agreed to allow Orca time to try to resolve the outstanding issue with respect to Orca's purported assignment of its interest in the Cowey #3H and #4H wells and to stay the pending arbitration. Ultimately, pursuant to an amendment to the Purchase and Sale Agreement between the parties, the Company agreed to bear 100% of the costs to drill, complete and equip the Cowey #3H and #4H wells. Until such time as the Company has recovered 100% of the costs to drill, complete and equip these wells, all revenues generated by production from these two wells will be attributable to the Company. Following the Company's recovery of these amounts, Orca would participate in the wells for a 25% working interest. The Company has returned $8.7 million submitted by Orca's putative assignee. The agreement also included a mutual release of claims between the Company and Orca and provided for dismissal of the Bexar County litigation. Orca filed a notice of non-suit of the Bexar County litigation on August 7, 2013.

The Company is also a defendant in several lawsuits encountered in the ordinary course of its business. In the opinion of management, it is remote that these lawsuits will have a material adverse impact on the Company's financial position, results of operations or cash flows.

General Federal and State Regulations

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 the cost of doing business and affects profitability. The Company believes that it is in material compliance with currently applicable state and federal regulations. Because these rules and regulations are frequently amended or reinterpreted, however, the Company is unable to predict the future cost or impact of complying with these regulations.

Environmental Regulations

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, installing and operating oil and natural gas wells. The

NOTE 13 — COMMITMENTS AND CONTINGENCIES — Continued

Company's activities are subject to a variety of environmental laws and regulations, including but not limited to the Oil Pollution Act of 1990, or OPA, the Clean Water Act, or CWA, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, the Resource Conservation and Recovery Act, or RCRA, the Clean Air Act, or CAA, the Safe Drinking Water Act, or SDWA, and the Occupational Safety and Health Act, or OSHA, as well as comparable state statutes and regulations. The Company is also subject to regulations governing the handling, transportation, storage and disposal of waste generated by its activities and of naturally occurring radioactive materials, or NORM, that may result from its 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. The Company has no outstanding material environmental remediation liabilities and believes that it is in material compliance with currently applicable environmental laws and regulations and that these laws and regulations will not have a material adverse impact on the financial position, results of operations or cash flows of the Company.

Changes in environmental laws and regulations occur frequently, however, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could, and in all likelihood would, materially adversely affect the Company's financial position, results of operations and cash flows, as well as those of the oil and natural gas industry in general. Because these rules and regulations are frequently amended or reinterpreted, the Company is unable to predict the future cost or impact of complying with these regulations. 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 federal or state laws or implementing regulations that may be adopted to address greenhouse gas emissions could, and in all likelihood would, require the Company to incur increased operating costs adversely affecting its financial position, results of operations and cash flows.

The Company's activities involve the use of hydraulic fracturing. 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) at the federal level. At the federal level and in some states, there have been efforts to place additional regulatory burdens on hydraulic fracturing 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 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. Additional burdens on hydraulic fracturing, such as reporting requirements or permitting requirements for the hydraulic fracturing activity, will result in additional expense and delay the Company's operations adversely affecting its financial position, results of operations and cash flows.

Oil and natural gas exploration and production, operations and other activities have been conducted at some of the Company's properties by previous owners and operators. Materials from these operations remain on some of the properties, and, in some instances, may require remediation. In addition, the Company occasionally must agree to indemnify sellers of producing properties the Company acquires against some or all of the liability for environmental claims associated with these properties. While the Company does not believe that the costs it incurs for compliance with environmental regulations and remediating previously or currently owned or operated properties will be material, the Company cannot provide assurances that these costs will not result in material expenditures that adversely affect its financial position, results of operations and cash flows.

The Company maintains insurance against some, but not all, potential risks and losses associated with the oil and natural gas industry and operations. The Company does not carry business interruption insurance. For some risks, the Company may not obtain insurance if it believes 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, and in all likelihood would, materially adversely affect the Company's financial position, results of operations and cash flows.

NOTE 14 — SUPPLEMENTAL DISCLOSURES

Accrued Liabilities

The following table summarizes the Company's current accrued liabilities at December 31, 2013 and 2012 (in thousands).

	December 31,	
	2013	2012
Accrued evaluated and unproved and unevaluated property costs	$52,605	$45,592
Accrued support equipment and facilities costs	—	1,382
Accrued stock-based compensation	56	65
Accrued lease operating expenses	6,251	5,218
Accrued interest on borrowings under Credit Agreement	141	255
Accrued asset retirement obligations	175	660
Accrued partners' share of joint interest charges	1,173	3,597
Other	3,586	2,410
Total accrued liabilities	$63,987	$59,179

Supplemental Cash Flow Information

The following table provides supplemental disclosures of cash flow information for the years ended December 31, 2013, 2012 and 2011 (in thousands).

	Year Ended December 31,		
	2013	2012	2011
Cash paid for interest expense, net of amounts capitalized	$5,801	$ 780	$ 634
Asset retirement obligations related to mineral properties	1,363	1,195	488
Asset retirement obligations related to support equipment and facilities	3	49	12
Increase in liabilities for oil and natural gas properties capital expenditures	7,548	24,847	1,864
Increase in liabilities for support equipment and facilities	660	1,112	175
Issuance of restricted stock units for Board and advisor services	274	73	—
Issuance of common stock for Board and advisor services	57	71	230
(Decrease) increase in liabilities for accrued cost to issue equity	—	(332)	(27)
Stock-based compensation expense recognized as liability	1,012	(1,092)	2,102
Transfer of inventory to oil and natural gas properties	343	69	96

NOTE 15 — SUBSIDIARY GUARANTORS

Matador filed a registration statement on Form S-3 with the SEC, which became effective May 9, 2013, and registered, among other securities, debt securities. The subsidiaries of Matador (the "Subsidiaries") are co-registrants with Matador, and the registration statement registers guarantees of debt securities by the Subsidiaries. As of December 31, 2013, the Subsidiaries are 100% owned by Matador, and any guarantees by the Subsidiaries will be full and unconditional (except for customary release provisions). Matador has no assets or operations independent of the Subsidiaries, and there are no significant restrictions upon the ability of the Subsidiaries to distribute funds to Matador. In the event that more than one of the Subsidiaries provide guarantees of any debt securities issued by Matador, such guarantees will constitute joint and several obligations.

NOTE 16 — SUBSEQUENT EVENTS

On March 12, 2014, the borrowing base under the Company's Credit Agreement was increased to $385.0 million based on the lenders' review of its proved oil and natural gas reserves at December 31, 2013. At that time, the Credit Agreement was also amended to include Wells Fargo Bank, N.A., which replaced Capital One, N.A., in the Company's lending group, which also includes RBC as administrative agent, Comerica Bank, Citibank, N.A., The Bank of Nova Scotia, SunTrust Bank, BMO Harris Financing, Inc. (Bank of Montreal) and IberiaBank. The amendment also provided that the borrowing base will automatically be reduced to the conforming borrowing base on the earlier of (i) June 30, 2015 or (ii) concurrent with the issuance by the Company of senior unsecured notes in an amount greater than or equal to $10.0 million. At March 13, 2014, the Company had $250.0 million in borrowings and $0.3 million in letters of credit outstanding under its Credit Agreement. The Company incurred $0.8 million of additional deferred loan costs in connection with the borrowing base redetermination and amendment of the Credit Agreement. These costs will be included with the remaining unamortized portion of the deferred loan costs of $2.1 million at December 31, 2013 to be amortized over the term of the agreement.

In February 2014, the Company granted awards of options to purchase 49,721 shares of the Company's common stock at an exercise price of $19.71 per share to certain of its employees. The fair value of these awards was approximately $0.4 million. The Company also granted awards of 19,787 shares of restricted stock to certain of its employees in February 2014. The fair value of these restricted stock awards was approximately $0.4 million. All of these awards vest over a term of four years. In March 2014, the Company granted awards of options to purchase 224,962 of the Company's common stock at an exercise price of $23.40 per share to certain of its employees. The fair value of these awards was approximately $2.2 million. The Company also granted awards of 67,690 shares of restricted stock to certain of its employees. The fair value of these awards was approximately $1.5 million. All of these awards vest over a term of four years.

Subsequent to December 31, 2013, the Company entered into new contracts with respect to its contracted drilling rigs. The Company's maximum outstanding termination obligations under its drilling rig contracts were approximately $13.7 million at March 13, 2014.

Subsequent to December 31, 2013, the Company agreed to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed, the Company will have minimum outstanding aggregate commitments for its participation in these wells of approximately $20.1 million at March 13, 2014, which it expects to incur within the next six months.

Unaudited Supplementary Information

MATADOR RESOURCES COMPANY AND SUBSIDIARIES
December 31, 2013, 2012 and 2011

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES

Costs Incurred

The following table summarizes costs incurred and capitalized by the Company in the acquisition, exploration and development of oil and natural gas properties for the years ended December 31, 2013, 2012 and 2011 (in thousands).

	Year Ended December 31,		
	2013	2012	2011
Property acquisition costs			
Proved	$ 176	$ —	$ —
Unproved and unevaluated	64,305	28,672	41,497
Exploration costs	99,104	115,084	108,662
Development costs	209,956	190,891	12,511
Total costs incurred	$373,451	$334,647	$162,670

Property acquisition costs are costs incurred to purchase, lease or otherwise acquire oil and natural gas properties, including both unproved and unevaluated leasehold and purchases of reserves in place. For the years ended December 31, 2013, 2012 and 2011, respectively, essentially all of the Company's property acquisition costs resulted from the acquisition of unproved and unevaluated leasehold positions.

Exploration costs are costs incurred in identifying areas of these oil and natural gas properties that may warrant further examination and in examining specific areas that are considered to have prospects of containing oil and natural gas, including costs of drilling exploratory wells, geological and geophysical costs, and costs of carrying and retaining unproved and unevaluated properties. Exploration costs may be incurred before or after acquiring the related oil and natural gas properties.

Development costs are costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil and natural gas. Development costs include the costs of preparing well locations for drilling, drilling and equipping development wells and related service wells (e.g., salt water disposal wells) and acquiring, constructing and installing production facilities.

Costs incurred also include new asset retirement obligations established, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table above were approximately $1.5 million, $1.2 million and $0.5 million for the years ended December 31, 2013, 2012 and 2011, respectively. Capitalized general and administrative expenses that are directly related to acquisition, exploration and development activities are also included in the table above. The Company capitalized $3.7 million, $2.6 million and $2.0 million of these internal costs in 2013, 2012 and 2011, respectively. Capitalized interest expense for qualifying projects is also included in the table above. The Company capitalized $1.9 million, $1.6 million and $1.3 million of its interest expense for the years ended December 31, 2013, 2012 and 2011, respectively.

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

Oil and Natural Gas Reserves

Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs using existing economic and operating conditions. 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 of that data can vary. The process also requires certain economic assumptions, including, but not limited to, oil and natural gas prices, drilling, completion and 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 most likely will vary from the Company's estimates.

The Company reports its production and proved reserves in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where the Company produces liquids-rich natural gas, such as in the Eagle Ford shale in South Texas and the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on these properties where the natural gas liquids are extracted and sold. The Company's oil and natural gas reserves estimates for the years ended December 31, 2013, 2012 and 2011 were prepared by the Company's engineering staff in accordance with guidelines established by the SEC and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

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. The commodity prices used to estimate oil and natural gas reserves are based on unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period. For the period from January through December 2013, these average oil and natural gas prices were $93.42 per barrel and $3.670 per MMBtu, respectively. For the period from January through December 2012, these average oil and natural gas prices were $91.21 per barrel and $2.757 per MMBtu, respectively. For the period from January through December 2011, these average oil and natural gas prices were $92.71 per barrel and $4.118 per MMBtu, respectively.

The Company's net ownership in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves are summarized as follows. All of the Company's oil and natural gas reserves are attributable to properties located in the United States. The estimated reserves shown below are for proved reserves only and do not include any value for unproved reserves classified as probable or possible reserves that might exist for these properties, nor do they include any consideration that could be attributed to interests in unevaluated acreage beyond those tracts for which reserves have been estimated. In the tables presented throughout this section, natural gas is converted to oil equivalent using the ratio of one Bbl of oil to six Mcf of natural gas.

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

	Net Proved Reserves		
	Oil (MBbl)	Gas (MMcf)	Oil Equivalent (MBOE)
Total at December 31, 2010	152	127,412	21,387
Revisions of prior estimates	51	(646)	(57)
Extensions and discoveries	3,745	58,164	13,439
Production	(154)	(14,512)	(2,573)
Total at December 31, 2011	3,794	170,418	32,196
Revisions of prior estimates	(782)	(103,375)	(18,010)
Extensions and discoveries	8,687	25,443	12,927
Production	(1,214)	(12,479)	(3,294)
Total at December 31, 2012	10,485	80,007	23,819
Revisions of prior estimates	(199)	78,812	12,936
Purchases of minerals in-place	—	170	28
Extensions and discoveries	8,209	66,121	19,231
Production	(2,133)	(12,915)	(4,285)
Total at December 31, 2013	16,362	212,195	51,729
Proved Developed Reserves			
December 31, 2010	152	43,143	7,342
December 31, 2011	1,419	56,547	10,843
December 31, 2012	4,764	54,040	13,771
December 31, 2013	8,258	53,458	17,168
Proved Undeveloped Reserves			
December 31, 2010	—	84,269	14,045
December 31, 2011	2,375	113,871	21,353
December 31, 2012	5,721	25,967	10,048
December 31, 2013	8,104	158,737	34,561

The following is a discussion of the changes in the Company's proved oil and natural gas reserves estimates for the years ended December 31, 2013, 2012 and 2011.

The Company's proved oil and natural gas reserves increased to 51,729 MBOE at December 31, 2013 from 23,819 MBOE at December 31, 2012. The Company's proved oil and natural gas reserves increased by 32,195 MBOE and the Company produced 4,285 MBOE during the year ended December 31, 2013, resulting in a net increase of 27,910 MBOE. An increase of 19,231 MBOE in proved oil and natural gas reserves was a result of extensions and discoveries during the year, which was primarily attributable to drilling operations in the Eagle Ford shale play in South Texas and additional proved undeveloped natural gas reserves identified on the Company's properties in the Haynesville shale. The Company's proved oil and natural gas reserves increased by 12,936 MBOE during the year as a result of revisions to previous estimates, primarily upward revisions in the Company's proved undeveloped natural gas reserves resulting from higher natural gas prices in 2013. The Company also purchased minerals in-place with proved reserves of 28 MBOE in 2013. The Company's proved developed oil and natural gas reserves increased to 17,168 MBOE at December 31, 2013 from 13,771 MBOE at December 31, 2012, primarily due to proved developed reserves added as a result of drilling operations in the Eagle Ford shale. At December 31, 2013, the Company's proved reserves were made up of approximately 32% oil and 68% natural gas.

The Company's proved oil and natural gas reserves decreased to 23,819 MBOE at December 31, 2012 from 32,196 MBOE at December 31, 2011. The Company's proved oil and natural gas reserves decreased by 5,083 MBOE and the Company produced 3,294 MBOE during the year ended December 31, 2012, resulting in a net decrease of 8,377 MBOE. An increase of 12,927 MBOE in proved oil and natural gas reserves was a result of extensions and discoveries during the year, which was primarily attributable to drilling operations in the Eagle Ford shale play in

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

South Texas. The Company's oil and natural gas reserves decreased by 18,010 MBOE during the year as a result of revisions to previous estimates, primarily resulting from lower natural gas prices in 2012. The Company's proved developed oil and natural gas reserves increased to 13,771 MBOE at December 31, 2012 from 10,843 MBOE at December 31, 2011, primarily due to proved developed reserves added as a result of drilling operations in the Eagle Ford shale. At December 31, 2012, the Company's proved reserves were made up of approximately 44% oil and 56% natural gas.

The Company's proved oil and natural gas reserves increased to 32,196 MBOE at December 31, 2011 from 21,387 MBOE at December 31, 2010. The Company increased its proved oil and natural gas reserves by 13,382 MBOE and produced 2,573 MBOE during the year ended December 31, 2011, resulting in a net gain of 10,809 MBOE. A total of 13,439 MBOE of the increase in proved oil and natural gas reserves was a result of extensions and discoveries during the year, all of which was attributable to drilling operations in the Eagle Ford shale play in South Texas and the Haynesville shale play in Northwest Louisiana. The Company's oil and natural gas reserves decreased by 57 MBOE during the year as a result of revisions to previous estimates, representing the net impact of small changes in prior estimates of proved reserves on a well-by-well basis. The Company's proved developed oil and natural gas reserves increased to 10,843 MBOE at December 31, 2011 from 7,342 MBOE at December 31, 2010, primarily due to proved developed reserves added as a result of drilling operations in the Eagle Ford and Haynesville shale plays. At December 31, 2011, the Company's proved reserves were made up of approximately 12% oil and 88% natural gas.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is not intended to provide an estimate of the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair market value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, potential improvements in industry technology and operating practices, the risks inherent in reserves estimates and perhaps different discount rates.

As noted previously, for the period from January through December 2013, the unweighted, arithmetic average of first-day-of-the-month oil and natural gas prices were $93.42 per barrel and $3.670 per MMBtu, respectively. For the period from January through December 2012, the comparable average oil and natural gas prices were $91.21 per barrel and $2.757 per MMBtu, respectively. For the period from January through December 2011, the comparable average oil and natural gas prices were $92.71 per barrel and $4.118 per MMBtu, respectively.

Future net cash flows were computed by applying these oil and natural gas prices, adjusted for all associated transportation and marketing costs, gravity and energy content, and regional price differentials, to year-end quantities of proved oil and natural gas reserves and accounting for any future production and development costs associated with producing these reserves; neither prices nor costs were escalated with time in these computations.

Future income taxes were computed by applying the statutory tax rate to the excess of future net cash flows relating to proved oil and natural gas reserves less the tax basis of the associated properties. Tax credits and net operating loss carryforwards available to the Company were also considered in the computation of future income taxes. Future net cash flows after income taxes were discounted using a 10% annual discount rate to derive the standardized measure of discounted future net cash flows.

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

The following table presents the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2013, 2012 and 2011 (in thousands).

	Year Ended December 31,		
	2013	2012	2011
Future cash inflows	$2,316,626	$1,273,882	$ 924,796
Future production costs	(666,450)	(325,413)	(194,538)
Future development costs	(507,923)	(244,283)	(235,469)
Future income tax expense	(181,041)	(77,821)	(83,840)
Future net cash flows	961,212	626,365	410,949
10% annual discount for estimated timing of cash flows	(382,544)	(231,729)	(195,476)
Standardized measure of discounted future net cash flows	$ 578,668	$ 394,636	$ 215,473

The following table summarizes the changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2013, 2012 and 2011 (in thousands).

	Year Ended December 31,		
	2013	2012	2011
Balance, beginning of period	$ 394,636	$ 215,473	$111,077
Net change in sales and transfer prices and in production (lifting) costs related to future production	(97,511)	(60,892)	53,903
Changes in estimated future development costs	(233,232)	16,937	(64,958)
Sales and transfers of oil and natural gas produced during the period	(209,338)	(116,142)	(53,478)
Purchases of reserves	176	—	—
Net change due to extensions and discoveries	386,696	358,159	182,282
Net change due to revisions in estimates of reserves quantities	260,148	(56,850)	(653)
Previously estimated development costs incurred during the period	106,348	9,750	1,023
Accretion of discount	36,184	24,873	11,987
Other	(371)	(290)	(1,335)
Net change in income taxes	(65,068)	3,618	(24,375)
Standardized measure of discounted future net cash flows	$ 578,668	$ 394,636	$215,473

SELECTED QUARTERLY FINANCIAL INFORMATION

The following table presents selected unaudited quarterly financial information for 2013 (in thousands, except per share data).

	December 31	September 30	June 30	March 31
2013				
Oil and natural gas revenues	$69,664	$81,868	$58,179	$ 59,319
Realized (loss) gain on derivatives	(390)	(1,165)	254	392
Unrealized (loss) gain on derivatives	(606)	(9,327)	7,526	(4,825)
Expenses	45,513	46,736	39,054	69,141
Other expense	724	1,972	1,754	1,204
Income (loss) before income taxes	22,431	22,668	25,151	(15,459)
Income tax provision (benefit)	7,056	2,563	32	46
Net income (loss)	$15,375	$20,105	$25,119	$(15,505)
Earnings (loss) per common share				
Basic				
Class A	$ 0.23	$ 0.35	$ 0.45	$ (0.28)
Class B	$ —	$ —	$ —	$ —
Diluted				
Class A	$ 0.23	$ 0.35	$ 0.45	$ (0.28)
Class B	$ —	$ —	$ —	$ —

The following table presents selected unaudited quarterly financial information for 2012 (in thousands, except per share data).

	December 31	September 30	June 30	March 31
2012				
Oil and natural gas revenues	$52,748	$38,008	$36,078	$ 29,164
Realized gain on derivatives	2,813	3,371	4,713	3,063
Unrealized (loss) gain on derivatives	(3,653)	(12,993)	15,114	(3,270)
Expenses	72,377	38,087	66,263	21,857
Other expense	907	89	31	235
(Loss) income before income taxes	(21,376)	(9,790)	(10,389)	6,865
Income tax (benefit) provision	(188)	(593)	(3,713)	3,064
Net (loss) income	$(21,188)	$ (9,197)	$ (6,676)	$ 3,801
Earnings (loss) per common share				
Basic				
Class A	$ (0.38)	$ (0.17)	$ (0.12)	$ 0.08
Class B	$ —	$ —	$ —	$ 0.15
Diluted				
Class A	$ (0.38)	$ (0.17)	$ (0.12)	$ 0.08
Class B	$ —	$ —	$ —	$ 0.15

Exhibit 31.1

CERTIFICATION

I, Joseph Wm. Foran, certify that:

1. I have reviewed this annual report on Form 10-K of Matador Resources Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 17, 2014

/s/ Joseph Wm. Foran

Joseph Wm. Foran
Chairman and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION

I, David E. Lancaster, certify that:

1. I have reviewed this annual report on Form 10-K of Matador Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 17, 2014

/s/ David E. Lancaster

David E. Lancaster
Executive Vice President, Chief Operating Officer
and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Matador Resources Company (the "Company") on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, Joseph Wm. Foran, Chairman and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 17, 2014

/s/ Joseph Wm. Foran

Joseph Wm. Foran
Chairman and Chief Executive Officer
(Principal Executive Officer)

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Matador Resources Company (the "Company") on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-K"), I, David E. Lancaster, Executive Vice President, Chief Operating Officer and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 17, 2014

/s/ David E. Lancaster

David E. Lancaster
Executive Vice President, Chief Operating Officer
and Chief Financial Officer
(Principal Financial Officer)

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CORPORATE INFORMATION

STOCK EXCHANGE LISTING

New York Stock Exchange (NYSE): MTDR

CORPORATE HEADQUARTERS

Matador Resources Company
One Lincoln Centre
5400 LBJ Freeway, Suite 1500
Dallas, Texas 75240
(972) 371-5200
For more information, please visit
www.matadorresources.com.

For Employment Opportunities, please visit

www.matadorresources.com/careers
Email: careers@matadorresources.com

STOCK TRANSFER AGENT AND REGISTRAR

Please direct general questions about shareholder accounts, stock certificates, transfer of shares or duplicate mailings to Matador Resources Company's transfer agent:

Registrar & Transfer Company
10 Commerce Drive
Cranford, NJ 07016
www.rtco.com
(800) 368-5948
Email: info@rtco.com

ANNUAL MEETING

The Annual Meeting of Shareholders will be held on Wednesday, June 4, 2014, at 9:30 a.m. CDT at the Hilton Anatole, 2201 N. Stemmons Freeway, Dallas, TX 75207.

FINANCIAL INFORMATION REQUESTS

To receive additional copies of our Annual Report on Form 10-K as filed with the SEC or to obtain other Matador Resources Company information, please contact Mac Schmitz at our corporate headquarters.

Email: info@matadorresources.com

OFFICER CERTIFICATIONS

Our Annual Report on Form 10-K filed with the SEC is included herein, excluding all exhibits other than our Sarbanes-Oxley Act Section 302 and 906 certifications by the CEO and CFO. We will send shareholders copies of the exhibits to our Annual Report on Form 10-K and any of our corporate governance documents, free of charge, upon request.

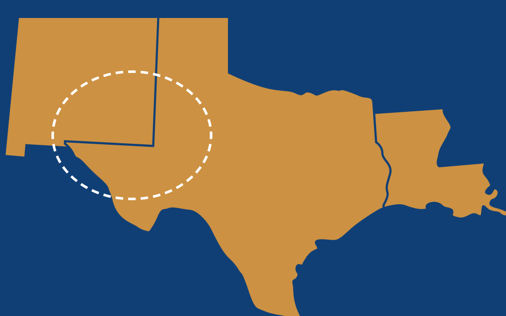
Note that these documents, along with further information about our history, board of directors, management team, operations and contact details, are available on our website at www.matadorresources.com.

MTDR LISTED NYSE

FORWARD-LOOKING STATEMENTS: This annual report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. "Forward-looking statements" are statements related to future, not past, events. Forward-looking statements are based on current expectations and include any statement that does not directly relate to a current or historical fact. In this context, forward-looking statements often address expected future business and financial performance, and often contain words such as "could," "believe," "would," "anticipate," "intend," "estimate," "expect," "may," "should," "continue," "plan," "predict," "potential," "project" and similar expressions that are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Actual results and future events could differ materially from those anticipated in such statements, and such forward-looking statements may not prove to be accurate. These forward-looking statements involve certain risks and uncertainties, including, but not limited to, the following risks related to financial and operational performance: general economic conditions; our ability to execute our business plan, including whether our drilling program is successful; changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids; our ability to replace reserves and efficiently develop our current reserves; our costs of operations; delays and other difficulties related to producing oil, natural gas and natural gas liquids; our ability to make acquisitions on economically acceptable terms; availability of sufficient capital to execute our business plan, including from our future cash flows, increases in our borrowing base and otherwise; weather and environmental conditions; and other important factors which could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. For further discussions of risks and uncertainties, you should refer to Matador's SEC filings, including the "Risk Factors" section of Matador's Annual Report on Form 10-K for the year ended December 31, 2013. Matador undertakes no obligation and does not intend to update these forward-looking statements to reflect events or circumstances occurring after the date of this annual report, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC. You are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this Annual Report. All forward-looking statements are qualified in their entirety by this cautionary statement.

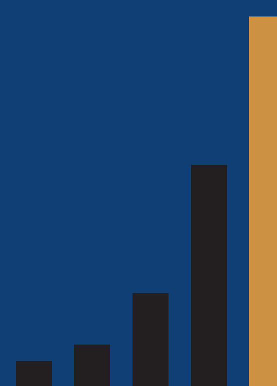
Matador RESOURCES COMPANY

BUILDING
PERMIAN POSITION



INCREASED
OIL PRODUCTION
+76%

GREW
ADJUSTED EBITDA
+65%



MTDR SHARE PRICE UP
127%
DURING 2013

MTDR LISTED NYSE

LONG HISTORY

MATADOR I 1988 – 2003
MATADOR II 2003 – PRESENT

Matador Resources Company | 5400 LBJ Freeway, Suite 1500 | Dallas, Texas 75240 | (972) 371-5200 | www.matadorresources.com