Midstates Petroleum Company, Inc.
Form 10-K
March 24, 2014

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

ý **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

o **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: 001-35512

MIDSTATES PETROLEUM COMPANY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**45-3691816**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
4400 Post Oak Parkway, Suite 1900; Houston, Texas	**77027**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(713) 595-9400**

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

Common stock, $0.01 par value	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

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 o No ý

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 o No ý

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

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 or any amendment to the Form 10-K ý

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No ý

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $180 million based upon the closing price of such stock on June 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, of $5.41 per share.

The number of shares outstanding of our stock at March 18, 2014 is shown below:

Class	**Number of shares outstanding**
Common stock, $0.01 par value	70,420,804

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements other than statements of historical fact included in this annual report are forward-looking statements, including, without limitation, statements regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management. When used in this annual report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward- looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- estimated future net reserves and present value thereof;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of oilfield labor;
- availability of third party natural gas gathering and processing capacity;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- drilling of wells, including our identified drilling locations;
- successful results from our identified drilling locations;

marketing of oil and natural gas;

the integration and benefits of asset and property acquisitions or the effects of asset and property acquisitions or dispositions on our cash position and levels of indebtedness;

infrastructure for salt water disposal and electricity;

sources of electricity utilized in operations and the related infrastructures;

costs of developing our properties and conducting other operations;

general economic conditions;

effectiveness of our risk management activities;

environmental liabilities;

counterparty credit risk;

the outcome of pending and future litigation;

governmental regulation and taxation of the oil and natural gas industry;

developments in oil-producing and natural gas-producing countries;

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- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this annual report that are not historical.

All forward-looking statements speak only as of the date of this annual report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this annual report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk Factors" and elsewhere in this annual report.

These factors include:

- variations in the market demand for, and prices of, oil, natural gas liquids and natural gas;
- uncertainties about our estimated quantities of oil and natural gas reserves;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our revolving credit facility;
- access to capital and general economic and business conditions;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- risks in connection with acquisitions, including the Eagle Property and Anadarko Basin Acquisitions;
- risks related to the concentration of our operations onshore in Oklahoma, Texas and Louisiana;
- drilling results;
- the potential adoption of new governmental regulations; and
- our ability to satisfy future cash obligations and environmental costs.

These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

GLOSSARY OF OIL AND NATURAL GAS TERMS

Bbl: One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

Boe: Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

Boe/d: Barrels of oil equivalent per day.

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

Dry hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production do not exceed production expenses and taxes.

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

MMBoe: One million barrels of oil equivalent.

MMBtu: One million British thermal units.

Net acres: The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

NYMEX: The New York Mercantile Exchange.

Proved reserves: Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for 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. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period prior to the ending date of the

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period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Reasonable certainty: A high degree of confidence.

Recompletion: The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reserves: Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development projects to known accumulations.

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

Spud or Spudding: The commencement of drilling operations of a new well.

Wellbore: The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

Working interest: The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on a cash, penalty, or carried basis.

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PART I

ITEM 1. BUSINESS

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See "Cautionary Note Regarding Forward Looking Statements" and "Risk Factors" located in this Form 10-K.

In this section, references to "the Company," "we," "us," "our," and "Midstates" when used in the present tense, prospectively or for historical periods since April 25, 2012, refer to Midstates Petroleum Company, Inc. and its subsidiary, and for historical periods prior to April 25, 2012, refer to Midstates Petroleum Holdings LLC and its subsidiary, unless the context indicates otherwise.

General

Midstates Petroleum Company, Inc. was incorporated pursuant to the laws of the State of Delaware on October 25, 2011 to become a holding company for Midstates Petroleum Company LLC ("Midstates Sub"), which was previously a wholly-owned subsidiary of Midstates Petroleum Holdings LLC. Pursuant to the terms of a corporate reorganization that was completed in connection with the closing of Midstates Petroleum Company, Inc.'s initial public offering on April 25, 2012, all of the interests in Midstates Petroleum Holdings LLC were exchanged for newly issued common shares of Midstates Petroleum Company, Inc., and as a result, Midstates Sub became a wholly-owned subsidiary of Midstates Petroleum Company, Inc. and Midstates Petroleum Holdings LLC ceased to exist as a separate entity. Our common stock, par value $0.01 per share, has been listed on the New York Stock Exchange (NYSE) since April 2012.

On October 1, 2012, the Company closed on the acquisition of all of Eagle Energy Production, LLC's ("Eagle Energy") producing properties and undeveloped acreage located primarily in the Mississippian Lime liquids play in Oklahoma for $325 million in cash, before customary post-closing adjustments, and 325,000 shares of the Company's Series A Mandatorily Convertible Preferred Stock (the "Series A Preferred Stock") with an initial liquidation preference value of $1,000 per share (the "Eagle Property Acquisition"). The Company funded the cash portion of the Eagle Property Acquisition purchase price with a portion of the net proceeds from the private placement of $600 million in aggregate principal amount of 10.75% senior unsecured notes due 2020 (the "2020 Senior Notes"), which also closed on October 1, 2012.

On May 31, 2013, the Company closed on the acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company, LLC and its partners for approximately $618 million in cash (the "Anadarko Basin Acquisition"), before customary post-closing adjustments. The Company funded the purchase price with a portion of the net proceeds from the private placement of $700 million in aggregate principal amount of 9.25% senior unsecured notes due 2021 (the "2021 Senior Notes" and, together with the 2020 Senior Notes, the "Senior Notes"), which also closed on May 31, 2013.

Subsequent to the closing of the Eagle Property Acquisition and the Anadarko Basin Acquisition, the Company has oil and gas operations and properties in Louisiana, Oklahoma and Texas. At December 31, 2013, the Company operated oil and natural gas properties and evaluated performance as one reportable segment as there were not significantly different economic or operational environments within its oil and natural gas properties.

On March 5, 2014, we executed a Purchase and Sale Agreement ("PSA") to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline

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Parish, Louisiana to a private buyer for a purchase price of $170 million in cash, subject to standard post-closing adjustments. The PSA has an effective date of November 1, 2013 and is expected to close on May 1, 2014. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and does not include our acreage and production in the western part of Louisiana in Beauregard Parish or other undeveloped acreage held outside the Pine Prairie field. The proceeds from the sale will be used to pay down our revolving credit facility.

The following table summarizes, by areas of operation, our estimated proved reserves as of December 31, 2013, their corresponding pre-tax PV-10 values and our fourth quarter 2013 average daily production rates (including those figures attributable to the Pine Prairie field that are subject to the PSA discussed above):

	Proved Reserves(1)						Average Daily Production for Three Months Ended December 31, 2013
						PV-10(3)	
Areas of Operation	**Oil (MBbl)**	**NGL (MBbl)**	**Gas (MMcf)**	**Total(2) (MBoe)**	**% Oil(4)**	**(in thousands)**	**(Boe/day)**
Mississippian	24,239	14,221	176,264	67,836	56%	$ 965,761	17,579
Anadarko Basin	15,816	8,555	75,612	36,973	66%	611,315	8,454
Gulf Coast	14,845	3,380	28,322	22,945	79%	490,758	5,154
Total	**54,900**	**26,156**	**280,198**	**127,754**	**63%**	**$ 2,067,834**	**31,187**
Discounted Future Income Taxes						(277,388)	
Standardized Measure of Discounted Future Net Cash Flows(3)						**$ 1,790,446**	

(1) Oil, natural gas liquids and natural gas reserve quantities and related discounted future net cash flows have been derived from oil, natural gas liquids and natural gas prices calculated using an average of the first-day-of-the month price for each month within the 12 months ended December 31, 2013, pursuant to current SEC and FASB guidelines.

(2) Barrel of oil equivalents are determined using a ratio of one Bbl of crude to six Mcf of natural gas, which represents their approximate relative energy content.

(3) Pre-tax PV-10 may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. We believe pre-tax PV-10 is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV-10 as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and natural gas properties and acquisitions. However, pre-tax PV-10 is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV-10 does not purport to present the fair value of our proved oil and natural gas reserves.

(4)

Includes volumes attributable to oil and NGLs.

During 2013, we incurred $1.2 billion in exploration, development and property acquisition expenditures, including $624.7 million for the Anadarko Basin Acquisition and $64.9 million for facilities and lease and seismic acquisition. Of the 124 wells spud in 2013, 121 gross (98 net) wells

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resulted in productive completions and three gross (and net) wells were unsuccessful, yielding a 98% success rate.

We expect to invest between $500 million and $550 million of capital for exploration, development and lease and seismic acquisition in 2014. Additionally, we expect to capitalize between $16 million and $22 million of interest expense.

Growth Strategy

Our goal is to grow our reserves, production and cash flows at an attractive rate of return on invested capital. We seek to achieve this goal through the following strategies:

Development of our multi-year drilling inventory. We intend to drill and develop our current acreage position to maximize the value of our primarily oil and liquids rich resource potential.

Mississippian. Our Mississippian assets acquired on October 1, 2012 are located in Oklahoma and target the Mississippian Lime and Hunton formations. The Mississippian Lime is an expansive carbonate hydrocarbon system located in the Anadarko Basin, primarily in northern Oklahoma. We currently intend to continue development of these liquids rich properties using horizontal wells and multi-stage frac technology. The Hunton formation is a limestone formation that produces primarily natural gas from our acreage in Lincoln County, Oklahoma. Because the Hunton targets primarily natural gas, our capital deployment will be focused on the Mississippian Lime until natural gas prices demonstrate sustained improvement from recent levels. At December 31, 2013, we had approximately 137,500 gross (97,200 net) acres under lease in the area, comprised of approximately 120,000 gross (84,300 net) leased acres in the Mississippian Lime and approximately 17,500 gross (12,900 net) acres in the Hunton. As of December 31, 2013, we had five drilling rigs in operation, and we currently have five drilling rigs in operation. We expect to spud between 95 to 105 gross (70 to 80 net) horizontal wells, including non-operated wells, during 2014 on this acreage.

Anadarko Basin. Our Anadarko Basin assets acquired on May 31, 2013 are located in Western Oklahoma and Texas and target multiple objectives in the Pennsylvanian section. Specifically we are currently targeting the Cleveland, Marmaton, Cottage Grove and Tonkawa formations by utilizing horizontal wells and multi-stage frac technology. At December 31, 2013, we had approximately 161,500 gross (129,800 net) acres under lease in the Anadarko Basin, comprised of approximately 42,700 gross (34,300 net) leased acres in Oklahoma and approximately 118,800 gross (95,500 net) acres in the Texas. As of December 31, 2013, we had five drilling rigs in operation in this area, and we currently have five drilling rigs in operation. We expect to spud between 70 to 75 gross (47 to 50 net) horizontal wells, including non-operated wells, during 2014 on this acreage.

Gulf Coast. Our Gulf Coast assets are located in Louisiana and are characterized by thick geologic sections of tight sands within the Tertiary Wilcox featuring multiple productive zones located within large geologic structural traps that are identifiable with 2D and 3D seismic data. Our primary operating areas have well-established production histories. At December 31, 2013 we had approximately 83,400 gross (81,200 net) acres under lease and/or lease option, comprised of 58,500 gross (56,500 net) acres under lease and 24,900 gross (24,700 net) acres under lease options, targeting large, well-defined geologic structures that we believe will increase our reserves, production and cash flow. With the addition of the Anadarko assets and increased activity in the Mississippian, we have shifted capital to those assets and dropped rigs in Louisiana. Our intent is to continue high grading inventory in Louisiana for future capital deployment. As of December 31, 2013, we had no drilling rigs in operation. We currently do not have any rigs in operation in the Gulf Coast area and expect a reduction in activity versus prior year due to our current focus on exploitation of our Mississippian assets and our recently acquired Anadarko Basin Assets. As discussed above, on March 5, 2014, we executed a PSA to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana to a private buyer. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres and is expected to close on May 1, 2014.

Disciplined financial management. We intend to maintain a disciplined approach to our financial management in order to preserve our financial stability. We believe that this approach includes targeting a conservative leverage profile and maintaining the liquidity to develop our asset base across industry cycles, as well as evaluating capital allocation decisions in the context of these goals. We have historically funded our activity through a combination of equity and debt securities, bank debt, and cash generated by operations. For example, we funded the Eagle Property Acquisition with a combination of cash proceeds from our $600 million 2020 Senior Notes offering and through the issuance of our Series A Preferred Stock. We funded the Anadarko Basin Acquisition with cash proceeds from our $700 million 2021 Senior Notes offering. In September 2013, our reserve-based borrowing base under our revolving credit facility was increased from $425 million to $500 million. To reduce variability in cash flow from our properties and to enhance our reserve based borrowing facility, we periodically enter into commodity derivative contracts and target hedging the maximum volumes permitted under our revolving credit facility, which currently equates to approximately 80% of our total current oil volumes from proved developed producing reserves. We believe the resulting increase in the predictability of our cash flow allows us to better schedule our development activities and maximize the productivity of those efforts. We may also consider the sale of selected assets or oil and gas interests to the extent those actions would help us achieve our targeted financial profile.

Maintain operatorship across a diverse asset base. Our diverse set of assets and high degree of operating control, facilitated by our position as operator on the majority of our properties, provide flexibility with respect to drilling and completion techniques and the timing and amount of capital expenditures that support growth and help us meet our targeted financial profile.

Utilize our technical and operating expertise to enhance returns. Our technical teams are focused on the application of modern reservoir evaluation and drilling and completion techniques to reduce risk and enhance returns in our core areas. We utilize 2D, 3D and micro seismic data, existing sub-surface well control data, detailed reservoir characterization and geologic and geochemical modeling to identify areas with significant exploration and development potential. These areas become targets for our leasing activity. Once we have identified a potential target, we attempt to maximize returns by applying modern drilling and completion techniques that maximize recoveries in a cost efficient and economically attractive manner. We utilize reservoir evaluation methods such as conventional and rotary sidewall coring, pressure sampling and other reservoir description techniques to better understand the ultimate potential of a particular area. We believe future development across our acreage position can be further optimized with specialized completion techniques, infill drilling, horizontal wellbore optimization and enhanced recovery methods.

Selectively increase our acreage position. While we believe our existing acreage positions provide significant growth opportunities in the Mississippian Lime, Anadarko Basin and the Upper Gulf Coast Tertiary trend, we continue to strategically increase our leasehold position in what we believe are the most prospective areas of our acreage. We believe our current Oklahoma and Texas acreage is highly prospective in the Pennsylvanian and Mississippian Lime sections and may be prospective in both shallower and deeper geologic sections. We plan to continue targeting additional onshore basins in North America that would allow us to extend our competencies to large undeveloped acreage positions in hydrocarbon trends similar to our existing core areas.

Apply rigorous investment analysis to capital allocation decisions. We employ rigorous investment analysis to determine the allocation of capital across our many drilling opportunities and in evaluating potential acquisitions. We are focused on maximizing the internal rate of return on our investment capital and screen drilling opportunities and acquisition opportunities by measuring risk and financial return, among other factors. We continually evaluate our inventory of potential investments by these measures, incorporating past drilling results, historical knowledge and new information we have gathered.

Our Competitive Strengths

We have a number of competitive strengths that we believe will help us to successfully execute our business strategies:

Oil and liquids weighted reserves, production and drilling locations with attractive economics. Our reserves, production and drilling locations are primarily oil with associated liquids rich natural gas. For the year ended December 31, 2013, our production was comprised of approximately 45% oil and 20% NGLs and our year-end reserves consisted of 43% oil, 20% NGL and 37% natural gas. In the Gulf Coast, we also benefit from selling our oil production to the Louisiana Light Sweet ("LLS") market, which has historically commanded a premium to West Texas Intermediate ("NYMEX WTI") oil prices due to its proximity to U.S. Gulf Coast refiners and the higher quality of the oil production sold in the LLS market. This premium has averaged approximately $14.88 per Bbl for the three years ended December 31, 2013. For the year ended December 31, 2013, the average realized price before the effect of commodity derivative contracts for our oil production was $99.18 per Bbl, compared to an average NYMEX WTI price of $98.05 per Bbl for the same period.

Extensive technical knowledge, history and early mover advantage in our areas of operations. In our Mississippian Lime area, we and our predecessor in the field have demonstrated an early mover advantage in acquiring and developing acreage in the trend, spudding 151 horizontal wells between 2010 and December 31, 2013. We believe our Mississippian team's early experience operating in this trend gives us a competitive advantage with respect to completion techniques and infrastructure development. In the Anadarko Basin area, we also feel that we have an advantage due to the history of drilling horizontally in several of the Pennsylvanian sands since 2005. We successfully hired many of the operation and technical personnel from Panther Energy, which will allow us to continue to build on their success in this area. We have had operations in the Upper Gulf Coast Tertiary trend since 1993. We believe our extensive operating experience in the trend provides us with an expansive technical understanding of the geology underlying our acreage and of the application of completion technologies and infrastructure design and optimization to our properties. We believe our relatively long history in the Gulf Coast area and experience interpreting well control data, core data and 2D and 3D seismic data provides us with an information advantage over our competitors in this trend and has allowed us to identify and acquire quality acreage at a relatively low cost. We believe we have developed amicable and mutually beneficial relationships with acreage owners in all of our core operating areas, which we believe also provides us with a competitive advantage with respect to our leasing and development activity. We also benefit from long-term relationships with local service companies and infrastructure providers that we believe contribute to our efficient low-cost operations.

Experienced and aligned management team with extensive operating expertise. Our management team has extensive operating expertise in the oil and gas industry and significant public company executive experience at major and large independent oil and gas companies and oilfield services companies, including Apache Corporation, Burlington Resources, ConocoPhillips and Anadarko Petroleum Corporation. Our management team has an average of 30 years of industry experience, including prior experience in various trends across the US and internationally. We believe our management team is one of our principal competitive strengths relative to our industry peers due to our team's proven track record of efficiently operating exploration and development programs. Additionally, our management team has a significant ownership interest in us, which we believe provides incentive for them to prudently grow the value of our business for the benefit of all our stakeholders.

Summary of Oil and Gas Properties and Operations

Mississippian Lime

Our Mississippian assets were acquired on October 1, 2012 and at December 31, 2013, consisted of approximately 84,300 net prospective acres in the Mississippian Lime trend, with 79,800 net acres in Woods and Alfalfa Counties of Oklahoma, which we currently believe is the core of the trend. We currently intend to develop these liquids-rich properties using horizontal wells. We also own approximately 12,900 net acres in Lincoln County, Oklahoma, which produces from, and is prospective in, the Hunton formation.

Our properties in this area represented 53% of our total proved reserves as of December 31, 2013. As of December 31, 2013, we held an average working interest and average net revenue interest of 71% and 55%, respectively, on our acreage in this area.

For the three months ended December 31, 2013 and 2012 and the year ended December 31, 2013, our average daily production from this area was as follows:

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	Year Ended December 31, 2013	Year Ended December 31, 2012(1)
Average daily production:				
Oil (Boe/d)	6,325	2,216	4,567	557
Natural gas liquids (Boe/d)	3,622	1,820	2,620	458
Natural gas (Mcf/day)	45,794	19,021	34,784	4,781
Average daily production (Boe/d)	17,579	7,207	12,985	1,812

(1) Note that as the Eagle Property Acquisition closed on October 1, 2012, this represents the impact to average annual production for the period of October 1, 2012 through December 31, 2012.

In this area, our main operating area is defined by de-risked acreage primarily in Woods County, where we are engaged in development drilling. Our current development drilling is targeting the Mississippian Lime interval, where we anticipate ultimate development of at least four horizontal wells per 640 acre section. We are also testing different completion techniques, including selective use of open hole completions, to determine the most cost effective design in this area.

During 2013, we invested approximately $315.9 million and drilled 75 horizontal wells in this region; in 2014, we plan to invest approximately $290 million to $330 million in the drilling of between 95 to 105 gross wells, including non-operated wells. Our plans are to continue to actively develop this area while evaluating exploration potential beyond our current position.

Expansion Areas Within Mississippian

All of our rigs currently operating in the Mississippian Lime are focused on infill drilling in our de-risked acreage; however, in the future, we plan to run one (or more) rigs in these areas to not only hold acreage but also de-risk the acreage.

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Anadarko Basin

Our Anadarko Basin assets were acquired on May 31, 2013, and at December 31, 2013, consisted of approximately 129,800 net acres in the Anadarko Basin, consisting of 95,500 net acres in Texas and 34,300 net acres in western Oklahoma. We took over operations of the properties on December 1, 2013. We currently intend to develop these liquids-rich properties using horizontal wells.

Our properties in this area represented 29% of our total proved reserves as of December 31, 2013. As of December 31, 2013, we held an average working interest and average net revenue interest of 80% and 53%, respectively, on our acreage in this area.

For the quarter ended December 31, 2013 and the period from May 31, 2013 through December 31, 2013, our average daily production from the area was as follows:

	Three Months Ended December 31, 2013	Year Ended December 31, 2013(1)
Average daily production:		
Oil (Boe/d)	3,940	2,239
Natural gas liquids (Boe/d)	1,816	1,082
Natural gas (Mcf/day)	16,190	9,559
Average daily production (Boe/d)	8,454	4,914

(1) Note that as the Anadarko Basin Acquisition closed on May 31, 2013, this represents the impact to average annual production for the period of May 31, 2013 through December 31, 2013. No data is available for the respective 2012 periods due to the timing of the acquisition.

During 2013, we invested approximately $96.2 million and drilled 35 horizontal wells; in 2014, we plan to invest approximately $170 million to $210 million in the drilling of between 70 to 75 gross wells, including non-operated wells. Our plans are to continue to actively develop this area while testing other potentially productive horizons within our current acreage and expansion areas beyond our current position.

Gulf Coast

In the Gulf Coast, our current acreage positions and evaluation efforts are concentrated in Louisiana in the Wilcox interval of the Upper Gulf Coast Tertiary trend and is characterized by well-defined geology, including tight sands featuring multiple productive zones typically located within large geologic traps. As of December 31, 2013, we had accumulated approximately 56,500 net acres in the trend and options to acquire an aggregate of approximately 24,700 additional targeted net acres.

Our development operations in the Gulf Coast area are currently focused on drilling vertical and horizontal wells and commingling production from multi-stage hydraulically fractured completions across stacked oil-producing intervals. As of December 31, 2013, we had drilled 144 wells in the trend, approximately 92% of which produced commercially, since the third quarter of 2008. Since that time, we have increased our average daily production from 995 Boe/d in the year ended December 31, 2008 to 6,027 Boe/d in the year ended December 31, 2013.

Our properties in this area represented 18% of our total proved reserves as of December 31, 2013. As of December 31, 2013, we held an average working interest and average net revenue interest of 97% and 73%; respectively, on our acreage in this area.

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For the quarter ended December 31, 2013 and 2012, and years ended December 31, 2013 and 2012, our average daily production from the area was as follows:

	Three Months Ended December 31,		Year Ended December 31,	
	2013	**2012**	**2013**	**2012**
Average daily production:				
Oil (Boe/d)	3,375	5,737	3,890	5,162
Natural gas liquids (Boe/d)	995	1,170	1,008	1,228
Natural gas (Mcf/day)	4,706	8,869	6,772	10,778
Average daily production (Boe/d)	5,154	8,385	6,027	8,187

During 2013, we invested approximately $148.9 million for exploration, development and lease and seismic acquisition and drilled 14 wells, including sidetracks, in the Gulf Coast area. In 2014, we currently plan to invest between $5 million and $10 million. We currently have no drilling rigs operating in this area as we have devoted our capital to developing our Mississippian and Anadarko Basin assets; however, we plan to continue to evaluate our acreage as well as other potential exploration opportunities in the Gulf Coast area.

The Gulf Coast areas of operation are concentrated in three core fields in Beauregard and Evangeline Parishes, Louisiana: Pine Prairie, South Bearhead Creek and North Coward's Gully. In Pine Prairie we spent $31.2 million of capital in 2013, continuing our vertical development of the deeper objectives in the Wilcox and Sparta with six vertical wells spud during the year. We spent $41.5 million in capital during 2013 in South Bearhead Creek spudding two horizontals and one vertical. Lastly, in 2013, we spent $55.6 million in capital and spud four horizontals, including one sidetrack, in the North Coward's Gully field.

On March 5, 2014, we executed a PSA to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana to a private buyer for a purchase price of $170 million, subject to standard post-closing adjustments. The PSA is expected to close on May 1, 2014. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and does not include our acreage and production in the western part of Louisiana in Beauregard Parish or other undeveloped acreage held outside the Pine Prairie field. Production from the assets included in this sale averaged 3,453 and 4,777 Boe/d during the years ended December 31, 2013 and 2012, respectively, and 2,366 and 5,361 Boe/d during the fourth quarters ended December 31, 2013 and 2012, respectively. Upon closing of the sale, our remaining Gulf Coast areas of operation will be concentrated in the South Bearhead and North Coward's Gully fields.

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Estimated Proved Reserves

	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Total (MBoe)
2011				
Proved Reserves				
Beginning Balance	11,927	314	27,906	16,892
Revision of previous estimates	(2,650)	1,661	(6,500)	(2,072)
Extensions, discoveries and other additions	8,049	2,364	22,204	14,114
Sales of reserves in place				
Purchases of reserves in place				
Production	(1,610)	(308)	(4,918)	(2,738)
Net proved reserves at December 31, 2011	**15,716**	**4,031**	**38,692**	**26,196**
Proved developed reserves, December 31, 2011	**6,479**	**1,802**	**17,987**	**11,279**
Proved undeveloped reserves, December 31, 2011	**9,237**	**2,229**	**20,705**	**14,917**
2012				
Proved Reserves				
Beginning Balance	15,716	4,031	38,692	26,196
Revision of previous estimates	(1,368)	(193)	(8,533)	(2,982)
Extensions, discoveries and other additions	12,262	3,232	32,646	20,935
Sales of reserves in place				
Purchases of reserves in place	13,010	7,745	85,293	34,969
Production	(2,093)	(617)	(5,695)	(3,659)
Net proved reserves at December 31, 2012	**37,527**	**14,198**	**142,403**	**75,459**
Proved developed reserves, December 31, 2012	**13,207**	**5,437**	**54,775**	**27,774**
Proved undeveloped reserves, December 31, 2012	**24,320**	**8,761**	**87,628**	**47,685**
2013				
Proved Reserves				
Beginning Balance	37,527	14,198	142,403	75,459
Revision of previous estimates	(13,511)	(3,259)	(20,762)	(20,230)
Extensions, discoveries and other additions	17,538	8,812	103,551	43,608
Sales of reserves in place				
Purchases of reserves in place	17,242	8,124	73,653	37,642
Production	(3,897)	(1,719)	(18,647)	(8,724)
Net proved reserves at December 31, 2013	**54,899**	**26,156**	**280,198**	**127,755**
Proved developed reserves, December 31, 2013	**19,853**	**10,321**	**111,410**	**48,743**
Proved undeveloped reserves, December 31, 2013	**35,046**	**15,835**	**168,788**	**79,012**

Our proved reserves have grown from 26.2 to 75.5 MMBoe from year end 2011 to year end 2012 and from 75.5 to 127.8 MMBoe from year end 2012 to year end 2013. Our reserve growth in these periods is due directly to the extensions and discoveries associated with our drilling activities in each year and, during 2012, the Eagle Property Acquisition and during 2013, the Anadarko Basin Acquisition. As a result, we have increased our average daily production at a compound annual growth rate of 89% from 995 Boe/d in the year ended December 31, 2008 to 23,927 Boe/d in the year ended December 31, 2013.

Our proved undeveloped reserves have grown from 47.7 MMBoe to 79.0 MMBoe from December 31, 2012 to December 31, 2013. During this time, we spent $249.2 million of our capital expenditures on drilling proved undeveloped locations and converted 11.3 MMBoe from proved undeveloped reserves to proved developed reserves. In addition, we added 43.6 MMBoe of proved

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undeveloped reserves through extensions and discoveries and had negative revisions of 20.2 MMBoe related to proved undeveloped reserves, of which 14.4 MMBoe related to reductions at our Gulf Coast Pine Prairie and West Gordon fields. These net negative revisions in the Gulf Coast were primarily due to higher development and lease operating costs which resulted in certain proved undeveloped locations becoming uneconomic as of December 31, 2013. We also added 37.6 MMBoe of proved reserves, primarily related to the closing of the Anadarko Basin Acquisition.

All of our proved undeveloped reserves as of December 31, 2013 are expected to be developed within five years of their initial booking.

Independent petroleum engineers

Mississippian and Gulf Coast Area Reserves

Our estimated reserves and related future net revenues at December 31, 2013 for the Mississippian and Gulf Coast areas are based on reports prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines in effect during such period established by the SEC. Our estimated reserves and related future net revenues for all areas at December 31, 2012 and 2011 were based on reports prepared by NSAI, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines in effect during such period established by the SEC.

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Robert C. Barg and Mr. Philip R. Hodgson. Mr. Barg has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Barg is a Licensed Professional Engineer in the State of Texas (No. 71658) and has over 30 years of practical experience in petroleum engineering, with over 24 years of experience in the estimation and evaluation of reserves. He graduated from Purdue University in 1983 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Hodgson has been practicing consulting petroleum geology at NSAI since 1998. Mr. Hodgson is a Licensed Professional Geoscientist in the State of Texas, Geophysics (No. 1314) and has over 29 years of experience in geological and geophysical studies and evaluations. He graduated from The University of Illinois in 1982 with a Bachelor of Science Degree in Geology and from Purdue University in 1984 with a Master of Science Degree in Geophysics. All technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; all are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Anadarko Area Reserves

For our Anadarko area, our estimated reserves and related future net revenues at December 31, 2013 are based on reports prepared by Cawley, Gillespie & Associates, Inc. ("CGA"), in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines in effect during such period established by the SEC.

The reserves estimates shown herein have been independently evaluated by CGA, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. CGA was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the reserves report incorporated herein was

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Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 26 years of practical experience in petroleum engineering, with over 24 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Technology used to establish proved reserves

Under Rule 4-10(a)(22) of Regulation S-X, as promulgated by the SEC, 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 proved 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 has been field tested and has 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, NSAI and CGA employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data.

Internal controls over reserves estimation process

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to NSAI and CGA in their reserves estimation process. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from the Company's accounting records, which are subject to external quarterly reviews, annual audits and their own set of internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. The Company's current ownership in mineral interests and well production data are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. At December 31, 2013, Clifford G. Zwahlen, PE, our former Vice President Corporate Reserves, was the technical person primarily responsible for overseeing the preparation of our reserve estimates and reported directly to the CEO. Prior to joining Midstates in March 2013, Mr. Zwahlen was the Manager of Reservoir Engineering Southern Region for Devon Energy, an oil and gas exploration and production company, from November 2011 to February 2013. Prior to that, from September 2009 to October 2011, he was the Reservoir Engineering

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Manager and Asset Lead for Devon's Carthage District in East Texas. From February 2008 to August 2009, Mr. Zwahlen was the Director of the Project Management Office for Devon's Shared Services Group and from March 2005 to February 2008 he held the position of Manager of Corporate Planning for Devon's Exploration and Production Business Unit. He also held management and engineering positions with EOG Resources and PetroCorp, Inc. Mr. Zwahlen currently serves on the Advisor Board for the MPGE School of the University of Oklahoma and the Petroleum Engineering Industry Board at Texas A&M University. He holds a degree in Petroleum Engineering from Texas A&M University and is a registered Professional Engineer in the state of Texas (License No. 76924). Throughout each fiscal year, our technical team meets with representatives of our independent reserve engineers to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the reserve report is reviewed by our senior management with representatives of our independent reserve engineers and internal technical staff.

In connection with our annual evaluation of the effectiveness of our internal control over financial reporting, we determined that, as of December 31, 2013, we did not maintain effective internal control over the accuracy and valuation of oil and gas reserves estimates. Specifically, controls were not operating effectively over the validation of the accuracy and completeness of certain source data provided to the independent third party reserve engineers. We also did not perform adequate management review of the independent third party reserves reports to determine if reserves estimates were complete and consistent with management's capital spending plans. These control deficiencies resulted in errors that, if not corrected, would have resulted in the misstatement of disclosures related to the value of oil and gas properties and associated reserve estimates. Please see "Management's Annual Report on Internal Control Over Financial Reporting" in Item 9A of this Annual Report.

Production, revenues and price history

Oil and natural gas are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand for oil and natural gas in the United States has increased dramatically during the past decade. However, the current economic slowdown during the second half of 2008 and through 2009 reduced this demand. Demand for oil increased during 2010, 2011 and 2012, but demand for natural gas has remained sluggish. Additionally, the price of natural gas has remained relatively depressed due to increasing supplies from shale plays, but has increased in recent months due to shortages caused by severe winter weather. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets. The following table sets forth information regarding oil, natural gas liquids and natural gas production, revenues and realized prices and production costs for the years ended December 31, 2013, 2012 and

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2011. For additional information on price calculations, see information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operation."

	Years Ended December 31,		
	2013	2012	2011
Operating Data:			
Net production volumes:			
Oil (MBbls)	3,904	2,093	1,610
NGLs (MBbls)	1,719	617	308
Natural gas (MMcf)	18,657	5,695	4,918
Total oil equivalents (MBoe)	8,733	3,659	2,737
Average daily production (Boe/d)	23,927	9,999	7,499
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 99.18	$ 104.35	$ 110.25
Oil, with realized derivatives (per Bbl)	$ 93.41	$ 95.05	$ 99.85
Natural gas liquids, without realized derivatives (per Bbl)	$ 36.26	$ 38.27	$ 50.98
Natural gas liquids, with realized derivatives (per Bbl)	$ 37.09	$ 40.48	(a)
Natural gas, without realized derivatives (per Mcf)	$ 3.39	$ 2.81	$ 4.20
Natural gas, with realized derivatives (per Mcf)	$ 3.58	$ 3.21	(a)
Costs and Expenses (per Boe of production):			
Lease operating and workover	$ 8.41	$ 8.34	$ 5.89
Gathering and transportation	$ 0.62	$	$
Severance and other taxes	$ 3.12	$ 6.81	$ 4.98
Asset retirement accretion	$ 0.17	$ 0.20	$ 0.12
Depreciation, depletion and amortization	$ 28.67	$ 34.32	$ 33.50
Impairment of oil and gas properties	$ 51.91	$	$
General and administrative	$ 6.10	$ 8.35	$ 25.18
Acquisition and transaction costs	$ 1.35	$ 4.07	$
Other	$ 0.07	$	$

(a) We did not have any hedges in place on our natural gas or NGL production prior to October 1, 2012.

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The following table sets forth information regarding oil, NGLs and natural gas production for each of the fields that represented more than 15% of our estimated total proved reserves as of December 31, 2013:

	Years Ended December 31,		
	2013	**2012**	**2011**
Mississippian(1)			
Net production volumes:			
Oil (MBbls)	4,550	203	
NGLs (MBbls)	1,908	123	
Natural gas (MMcf)	30,070	1,289	
Total oil equivalents (MBoe)	**11,470**	**541**	
Anadarko(2)			
Net production volumes:			
Oil (MBbls)	2,239		
NGLs (MBbls)	1,082		
Natural gas (MMcf)	9,559		
Total oil equivalents (MBoe)	**4,914**		

(1) These volumes represent only Mississippian Lime production and do not include Hunton volumes.

(2) Anadarko volumes include production from May 31, 2013, the date of acquisition of the Anadarko Basin Properties, through December 31, 2013.

Productive Wells

The following table presents our total gross and net productive wells as of December 31, 2013:

	Oil		Natural Gas		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Total productive wells	617	463	105	79	722	542

Gross wells are the number of wells in which a working interest is owned, and net wells are the total of our fractional working interest owned in gross wells.

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we have a controlling interest as of December 31, 2013 for each of our operating areas. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Mississippian	94,287	61,843	43,248	35,316	137,535	97,159
Anadarko Basin	102,992	82,783	58,541	47,054	161,533	129,837
Gulf Coast	16,326	16,313	67,061	64,899	83,387	81,212
Total	**213,605**	**160,939**	**168,850**	**147,269**	**382,455**	**308,208**

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Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2013 that will expire over the next three years by operating area unless production is established within the spacing units covering the acreage or we make additional lease rental payments prior to the expiration dates:

	Expiring 2014		Expiring 2015		Expiring 2016	
	Gross	Net	Gross	Net	Gross	Net
Mississippian	28,203	20,046	4,945	4,543	9,594	8,990
Anadarko Basin	39,861	32,039	13,578	8,066	11,696	6,949
Gulf Coast	1,914	1,875	3,738	3,537	33,235	32,318
Total Undeveloped Acreage Expirations	**69,978**	**53,960**	**22,261**	**16,146**	**54,525**	**48,257**

Excluding the Anadarko Basin Acquisition, approximately 12% of our net acreage, including acreage under option, was acquired in 2013, with the majority of such leases under three year primary term leases. In addition, our typical lease terms along with unit regulatory rules generally provide us flexibility to continue lease ownership through either establishing production or actively drilling prospects.

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2013, 2012 and 2011. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	Years Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	121	98	68	64	29	29
Dry holes	1	1	7	7		
Total	**122**	**99**	**75**	**71**	**29**	**29**
Exploratory wells:						
Productive			4	3	2	2
Dry holes	2	2				
Total	**2**	**2**	**4**	**3**	**2**	**2**
Total wells	**124**	**101**	**79**	**74**	**31**	**31**

As of December 31, 2013, no exploratory wells were being drilled and seven gross (and net) development wells were currently drilling.

Our drilling activity has increased over the last three years, and we were operating ten drilling rigs on our properties as of December 31, 2013. Our recent drilling activity has primarily focused on development and delineation and appraisal of our primary operating areas in the Mississippian and Anadarko Basin. In addition to the drilling activity listed above, a portion of our capital program over the last three years has also been focused on re-entering and recompleting productive zones in existing wellbores. In 2013 we had a total of three gross (and net) that were deemed dry hole wells, two of which were geologic dry holes and one of which was caused by mechanical problems encountered while drilling which prevented us from reaching the reservoir targets.

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Marketing and Major Customers

We sell our oil, natural gas liquids and natural gas to third-party purchasers. We are not dependent upon, or contractually limited to, any one purchaser or small group of purchasers other than in our Mississippian region where a portion of our natural gas production is dedicated to one purchaser for the economic life of the relevant assets. For the year ended December 31, 2013, ConocoPhillips, Chevron, Gulfmark, Semgas and Valero Marketing accounted for 28%, 16%, 13%, 12%, and 11% of our revenues, respectively. For the year ended December 31, 2012, Chevron, Gulfmark and Targa accounted for 41%, 32% and 10% of our revenues, respectively. For the year ended December 31, 2011, Chevron and Gulfmark accounted for 39% and 38% of our revenues, respectively. Due to the nature of oil, natural gas and NGL markets, and because we sell our oil production to purchasers that transport by truck rather than by pipelines, we do not believe the loss of a single purchaser or a few purchasers would materially adversely affect our ability to sell our production.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties and, depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with their use or affect our carrying value of the properties.

Seasonality

Generally, demand for oil and natural gas decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations.

Winter weather conditions can limit or temporarily halt our drilling and producing activities and other oil and natural gas operations, including gas processing, access to electricity and transportation. Additionally, once production comes back online following a cessation due to weather, it may take a period of time before production from a well reaches the level it was at prior to the cessation. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

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Competition

The oil and natural gas industry is highly competitive. We compete with numerous entities, including major domestic and foreign oil companies, other independent oil and natural gas companies and individual producers and operators. Many of these competitors are large, well established companies and have financial and other resources substantially greater than ours. Our ability to acquire additional oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and successfully consummate transactions in a highly competitive environment.

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and produced during operations and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations, such laws and regulations are frequently amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of transportation and sale of oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. The price we receive from the sale of these products may be affected by the cost of transporting the products to market. For our oil production, all of that transportation is currently via truck and we do not rely on interstate or intrastate pipelines.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC's pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC under Order No. 637 will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission ("CFTC") and the Federal Trade Commission ("FTC"). Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of our operations may be required to annually report to FERC on May 1 of each year for the previous calendar year. Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted.

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case by case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future. Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. 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. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. 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.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Other federal laws and regulations affecting our industry

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 ("EPAct 2005"). EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1.0 million per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1.0 million per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction,

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which now includes the annual reporting requirements under Order No. 704. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations, and orders, we could be subject to substantial penalties and fines.

FERC Market Transparency Rules. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the FTC issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale from: (a) knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1.0 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

Additional proposals and proceedings that might affect the oil and natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Environmental and occupational health and safety regulation

Our oil and natural gas exploration, development and production operations are subject to stringent and complex federal, regional, state and local laws and regulations governing occupational safety and health, the emission or discharge of materials into the environment and environmental protection. Numerous governmental entities, including the U.S. Environmental Protection Agency ("EPA"), analogous state agencies, and, in certain instances, citizens' groups, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close waste pits and plug abandoned wells; (v) impose specific safety and health criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of injunctions prohibiting some or all of our operations. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would

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otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in federal or state environmental laws and regulations or re-interpretation of applicable enforcement policies that result in more stringent and costly well construction, drilling, water management or completion activities, or waste handling, storage, transport, disposal or remediation requirements or that limit or otherwise restrict the emission of certain pollutants or organic compounds from wells or surface equipment 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 cannot assure you 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. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that we will be able to remain in compliance in the future with existing or any new laws and regulations or that future compliance with such laws and regulations will not have a material adverse effect on our business and operating results.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and wastes

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These classes of persons include current and prior owners or operators of the site where the release occurred and entities that disposed of or arranged for the disposal of the hazardous substances at a site where a release has occurred. Under CERCLA, these "responsible parties" may be subject to strict, joint and several liability for the costs of removing and cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses crude oil and natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes and nonhazardous solid wastes. Under the authority of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of oil and natural gas from regulation as hazardous wastes, we can provide no assurance that this exemption will be preserved in the future. From time to time the EPA and analogous state agencies have considered repealing or modifying this exemption, and citizens' groups have also petitioned the agency consider its repeal. Repeal or modification of this exemption or similar exemptions under state law could have a significant impact on our operating costs as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted. In any event, at present, these excluded wastes are subject to regulation as nonhazardous solid wastes. In addition, we generate petroleum hydrocarbon wastes and ordinary industrial wastes in the course of our operations that may become regulated as hazardous wastes if such wastes have hazardous characteristics.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where these petroleum hydrocarbons and wastes have been taken for recycling or disposal. In addition, certain of these properties have been operated by the third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination.

Air emissions

The Clean Air Act, as amended ("CAA"), and comparable state laws, regulate emissions of various air pollutants through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in August 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, beginning in January 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. We continue to review these rules and assess their potential impacts on our operations. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

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Climate change

Recent scientific studies have suggested that emissions of certain greenhouse gases ("GHGs"), which include carbon dioxide and methane, may be contributing to warming of the earth's atmosphere and other climatic changes. In December 2009, the EPA published its findings that emissions of greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act that establish pre-construction and operating permitting requirements for GHG emissions from certain large stationary sources. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities on an annual basis, which includes certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. In addition, in August 2012, the EPA established new source performance standards for volatile organic compounds and sulfur dioxide and an air toxic standard for oil and natural gas production, transmission, and storage activities. The rules include the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several other sources, such as storage tanks and other equipment, and limits methane emissions from these sources in an effort to reduce GHG emissions. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. We cannot predict which areas, if any, the EPA may choose to regulate with respect to GHG emissions next.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on our operations and the industry in general. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, such requirements could require us to obtain permits for our GHG emissions, install costly emission controls, and adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Water discharges

The Federal Water Pollution Control Act, as amended (the "Clean Water Act"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities, including oil and natural gas production facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for

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noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990, as amended ("OPA"), amends the Clean Water Act and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Hydraulic fracturing activities

Hydraulic fracturing is an important and common industry practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; however, to date, the agency has taken no action to do so. In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states, including Louisiana, Texas and Oklahoma, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nevertheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released in December 2012 and a final report expected to be available for public comment and peer review sometime in 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities sometime in 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We only use qualified contractors to perform hydraulic fracturing activities at our properties who have experience performing fracturing services on similar properties and who have demonstrated to our satisfaction that they employ appropriate safeguards to ensure that hydraulic fracturing will be performed in a safe and environmentally protective manner. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party claims related to hydraulic fracturing operations conducted by third parties and associated legal expenses in accordance with, and subject to, the terms and coverage limits of such policies.

Endangered Species Act considerations

The federal Endangered Species Act, as amended ("ESA"), restricts exploration, development and production activities that may affect endangered and threatened species or their habitats. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits the taking of endangered species. Federal agencies are required to insure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to make a determination on a listing of more than 250 species as endangered or threatened under the ESA over the next six years, through the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Employees

As of December 31, 2013, we employed 217 people, including 56 technical (geosciences, engineering, land), 100 field operations, 52 corporate (finance, accounting, planning, business development, legal, office management) and nine management.

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Offices

We currently lease approximately 41,200 square feet of office space in Houston, Texas at 4400 Post Oak Parkway, Suite 1900, where our principal offices are located. The lease for our Houston office expires in 2018. We also lease two field offices in Louisiana, one in Perryton, Texas and approximately 57,000 square feet of office space in Tulsa, Oklahoma at 321 South Boston Avenue, Suite 600. The lease for our Tulsa office expires in 2021.

Available Information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol "MPO." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website (http://www.midstatespetroleum.com) all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Financial Code of Ethics, and the charters of our audit committee, compensation committee and nominating and governance committee are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to 4400 Post Oak Parkway, Suite 1900; Houston, Texas 77027, attention Corporate Counsel. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

ITEM 1A. RISK FACTORS

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K in our other public filings, press releases and discussions with our management actually occurs, our business, financial condition or results of operations could suffer. The risks described below are the known material risk factors facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks Related to the Oil and Gas Industry and Our Business

A substantial or extended decline in oil and, to a lesser extent, natural gas, prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas, heavily influences our revenue, profitability, access to capital 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. These markets 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 beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;

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- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil and natural gas-producing countries;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic, local and foreign governmental regulations and taxes;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is currently sold to purchasers under short-term (less than 12-month) contracts at market based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. If oil and natural gas prices deteriorate, we anticipate that the borrowing base under our revolving credit facility, which is revised periodically, may be reduced. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices could render uneconomic a significant portion of our identified drilling locations. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our development, drilling and production activities. Our oil and natural gas drilling and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore or develop drilling locations or properties will depend in part on the evaluation of data obtained through 2D and 3D seismic data, geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The production and operating data that is available with respect to our operating areas based on modern drilling and completion techniques is relatively limited compared to trends where multiple operators have been active for a significant period of time. As a result, we face more uncertainty in evaluating data than operators in more developed trends. For a discussion of the uncertainty involved in these processes, see " Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these assumptions will materially affect the quantities and present value of our reserves." Our costs of drilling, completing and operating wells are often uncertain before drilling commences. In addition, the application of new techniques in these trends, such as high-graded stimulation designs and horizontal completions, some of which we may not have previously employed, may make it more difficult to accurately estimate these costs. Overruns in budgeted expenditures are

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common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of, or delays in, obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.

In addition, our hydraulic fracturing operations require significant quantities of water. Regions where we operate have recently experienced drought conditions. These conditions could persist in the future, diminishing our access to water for hydraulic fracturing operations. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail our operations or otherwise result in delays in operations or increased costs.

The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2013, 2012 and 2011, we based the discounted future net cash flows from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and

changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Prior to our corporate reorganization in April 2012 in connection with our initial public offering, we were not subject to entity level taxation. Accordingly, our standardized measure for periods prior to such reorganization does not provide for federal or state corporate income taxes because taxable income was passed through to our equity holders. However, as a result of our corporate reorganization, we are now treated as a taxable entity for federal income tax purposes and our income taxes are dependent upon our taxable income. Actual future prices and costs

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may differ materially from those used in the present value estimates included in this report which could have a material effect on the value of our reserves.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties. We use the full cost method of accounting for our oil and gas properties.

Accordingly, we capitalize and amortize all productive and nonproductive costs directly associated with property acquisition, exploration and development activities. Under the full cost method, the capitalized cost of oil and gas properties, less accumulated amortization and related deferred income taxes may not exceed the "cost center ceiling" which is equal to the sum of the present value of estimated future net revenues from proved reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, plus the costs of properties not subject to amortization, plus the lower of the cost or estimated fair value of unproved properties included in the costs being amortized, less related income tax effects. If the net capitalized costs exceed the cost center ceiling, we recognize the excess as an impairment of oil and gas properties. At December 31, 2013, we recognized an impairment of $319.6 million, net of taxes, for the amount by which our net capitalized costs exceeded the cost center ceiling. This impairment does not impact cash flows from operating activities but does reduce our earnings and shareholders' equity. The risk that we will be required to recognize impairments of our oil and natural gas properties increases during periods of low commodity prices. In addition, impairments would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices increase the cost center ceiling applicable to the subsequent period. We could incur impairments of oil and natural gas properties in the future, particularly as a result of a decline in commodity prices.

Our level of indebtedness may increase and reduce our financial flexibility.

As of December 31, 2013, we had $99 million available and a borrowing base of $500 million under our revolving credit facility, $600 million in 2020 Senior Notes and $700 million in 2021 Senior Notes outstanding. In the future, we may incur significant additional indebtedness in order to make future acquisitions or to develop our properties.

Our current level of indebtedness could affect our operations in several ways, including the following:

- causing a significant portion of our cash flows to be used to service our indebtedness, thereby reducing the availability of cash flows for working capital, capital expenditures and other general business activities;
- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- placing us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, such competitors may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- causing our debt covenants to affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- making it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then outstanding bank borrowings;

- impairing our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and

- making it more difficult for us to satisfy our obligations under the indentures governing our Senior Notes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control.

If we are unable to repay our debt out of our cash on hand, we could attempt to refinance such debt, obtain additional borrowings, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that refinancing, additional borrowings, proceeds from the sale of assets or equity financing will be available to pay or refinance such debt. Factors that may affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions, our market value, our reserve levels and our operating performance at the time of such offering or other financing. The inability to repay or refinance our debt could have a material adverse effect on our operations and could result in a reduction in our capital program or lead us to pursue other alternatives to develop our assets.

In addition, our bank borrowing base is subject to periodic redeterminations on a semi-annual basis, effective October 1 and April 1 and up to one additional time per six-month period following each scheduled borrowing base redetermination, as may be requested by either us or the administrative agent under our revolving credit facility. In the future we could be forced to repay a portion of our then outstanding bank borrowings due to future redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are unable to arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

We have incurred losses from operations during certain periods since the beginning of 2008 and may continue to do so in the future.

We incurred losses from operations of $407.4 million, $15.6 million and $11.8 million for the years ended December 31, 2013, 2010 and 2009, respectively. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this report may impede our ability to economically acquire and develop oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See "Summary of Oil and Gas Properties and Operations" for information about our estimated oil and natural gas reserves.

In order to prepare our estimates, we must estimate production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and

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engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Estimates of oil and natural gas reserves are inherently imprecise. In addition, reserve estimates for properties that do not have a lengthy production history, including the areas in which we operate, are less reliable than estimates for fields with lengthy production histories. There can be no assurance that analysis of previous production data relating to the Mississippian Lime, Anadarko Basin or Upper Gulf Coast Tertiary trend will accurately predict future production, development expenditures or operating expenses from wells drilled and completed using modern techniques. In addition, this data is partially based on vertically drilled wells, which may not accurately reflect production, development expenditures or operating expenses that may result from the application of horizontal drilling techniques.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

The development of our proved undeveloped reserves in our areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 62% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2013. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify proved reserves as unproved reserves.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations will be adversely affected.

Drilling locations that we have identified may not yield oil or natural gas in commercially viable quantities.

We describe some of our drilling locations and our plans to explore those drilling locations in this report. Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. 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 drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities 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 from or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent production prior to the expiration date of leases for such locations. In addition, we may not be able to raise the amount of capital that would be necessary to drill a substantial portion of our identified drilling locations.

Our management team has identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage and acreage currently under option. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these drilling locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results, lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques. The results of our horizontal drilling activities are subject to drilling and completion technique risks, and actual drilling results may not meet our expectations for reserves or production. As a result, we may incur material impairment of the carrying value of our unevaluated properties, and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Risks that we face while horizontally drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our horizontal wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Ultimately, the success of these horizontal drilling and completion techniques can only be evaluated over time as more wells are drilled in the Mississippian Lime, Anadarko Basin and Upper Gulf Coast Tertiary trend and production profiles are established over a sufficiently long time period. If our horizontal drilling results in these trends are less than anticipated, the return on our investment in this area may not be as attractive as we anticipate. The carrying value of our unevaluated properties could become impaired, which would increase our depletion rate per Boe or result in a ceiling test impairment if there were no corresponding additions to recoverable reserves, and the value of our undeveloped acreage in this area could decline in the future.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

We utilize third-party services to maximize the efficiency of our organization. The cost of oilfield services may increase or decrease depending on the demand for services by other oil and gas companies. There is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages or the high cost of frac crews, drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our business depends on transportation by truck for our oil and condensate production, and our natural gas production depends on transportation facilities that are owned by third parties.

We transport all of our oil and condensate production by truck, which is more expensive and less efficient than transportation via pipeline. Our natural gas production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

The disruption of third-party facilities due to maintenance or weather could negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flows, and if a substantial portion of the production is hedged at lower than current market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows.

Our drilling and production programs may not be able to obtain access on commercially reasonable terms or otherwise to truck transportation, pipelines, gas gathering, transmission, storage and processing facilities to market our oil and gas production.

The marketing of oil and gas production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities. Access to such facilities is, in many respects, beyond our control. If these facilities were unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise. The amount of oil and gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

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We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, or increases in interest rates. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to drill our identified locations and pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent disruptions and continuing volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

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Our revolving credit facility and the indentures governing our Senior Notes contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our revolving credit facility and the indentures governing our Senior Notes includes certain covenants that, among other things, restrict:

- our ability to incur or assume additional debt or provide guarantees in respect of obligations of other persons;
- issue redeemable stock and preferred stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- create or incur liens;
- restrict distributions from our subsidiaries;
- sell assets and capital stock of our subsidiaries;
- consolidate or merge with or into another entity, or sell all or substantially all of our assets; and
- enter into new lines of business.

A breach of the covenants under the indentures governing the Senior Notes or under the revolving credit facility could result in an event of default under the applicable indebtedness. An event of default may allow the creditors to accelerate the related debt and may result in an acceleration of any other debt to which a cross-acceleration or cross-default provision applies. In addition, an event of default under our credit facility would permit the lenders under the facility to terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders under our revolving credit facility could proceed against the collateral granted to them to secure that debt.