Midstates Petroleum Company, Inc.
Form 10-K
March 16, 2015

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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, 2014

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 (State or other jurisdiction of incorporation or organization)	**45-3691816** (I.R.S. Employer Identification No.)
321 South Boston, Suite 1000 **Tulsa, Oklahoma** (Address of principal executive offices)	**74103** (Zip Code)

Registrant's telephone number, including area code: **(918) 974-8550**

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

Common stock, $0.01 par value (Title of each class)	**New York Stock Exchange** (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 $272 million based upon the closing price of such stock on June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, of $7.23 per share.

The number of shares outstanding of our stock at March 9, 2015 is shown below:

Class	**Number of shares outstanding**
Common stock, $0.01 par value	72,196,132

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Midstates Petroleum Company, Inc. for the Annual Meeting of Shareholders to be held in May 2015, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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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;
- financial condition, revenues, cash flows and expenses;
- levels of indebtedness, liquidity and compliance with debt covenants;
- 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;
- 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;
- 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. The price of oil and natural gas declined significantly in late 2014 and early 2015. Any continued or extended decline in oil and natural gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital. 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.

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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/day: 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 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.

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 Annual Report on Form 10-K.

In this section, references to "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 (the "NYSE") since April 2012.

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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.

On May 1, 2014, the Company closed on the sale of all of its 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 in cash, before customary post-closing adjustments. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and did not include our acreage and production in the western part of Louisiana in Beauregard and Calcasieu Parish or other undeveloped acreage held outside the Pine Prairie field.

The Company has oil and gas operations and properties in Oklahoma, Texas and Louisiana. At December 31, 2014, the Company operated oil and natural gas properties as one reportable segment engaged in the exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas. The Company's management evaluated performance based on one reportable segment as there were not significantly different economic or operational environments within its oil and natural gas properties.

The following table summarizes, by areas of operation, our estimated proved reserves as of December 31, 2014, their corresponding pre-tax PV-10 values and our fourth quarter 2014 average daily production rates:

	Proved Reserves(1)						Average Daily Production for Three Months Ended December 31, 2014
	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Total(2) (MBoe)	% Oil(4)	PV-10(3) (in thousands)	(Boe/day)
Areas of Operation							
Mississippian	51,494	28,957	350,064	138,796	58%	$ 2,055,345	25,039
Anadarko Basin	4,963	3,011	26,176	12,336	65%	262,705	7,337
Gulf Coast	1,785	560	1,605	2,612	90%	68,336	1,388
Total	**58,242**	**32,528**	**377,845**	**153,744**	**59%**	**$ 2,386,386**	**33,764**
Discounted Future Income Taxes						(513,025)	
Standardized Measure of Discounted Future Net Cash Flows(3)						**$ 1,873,361**	

(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, 2014, pursuant

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to current SEC and FASB guidelines and were $94.99/Bbl for oil, $39.17/Bbl for NGLs and $4.35 per MMBtu for natural gas.

(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 2014, we incurred the following operational and total capital expenditures (in thousands):

	For the Three Months Ended December 31, 2014	For the Twelve Months Ended December 31, 2014
Drilling and completion activities	$ 116,279	$ 511,295
Acquisition of acreage and seismic data	4,032	19,150
Operational capital expenditures incurred	**$ 120,311**	**$ 530,445**
Capitalized G&A, office, ARO & other	2,789	12,081
Capitalized interest	1,870	12,414
Total capital expenditures incurred	**$ 124,970**	**$ 554,940**

As noted above, we incurred operational capital expenditures of $530.4 million during the year ended December 31, 2014, of which $383.2 million was spent in the Mississippian Lime, $139.8 million was spent in the Anadarko Basin and $7.4 million was spent in the Gulf Coast area. We expect to invest between $250 million and $275 million of capital for exploration, development and lease and seismic acquisition in 2015. Additionally, we expect to capitalize between $4 million and $6 million of interest expense.

Strategies

Our goal is to grow our reserves, production and cash flows at an attractive rate of return on invested capital. To achieve these objectives, we strive to:

Operate in a safe and environmentally responsible manner;

Allocate capital to projects that generate the highest returns;

Maintain a sustainable, diverse inventory of low-cost, high-margin resource plays;

Drill in the highest potential areas of the resource plays in which we operate;

Build contiguous acreage positions that drive operating efficiencies;

Be the operator of our assets, whenever possible;

Be the low-cost driller and producer in each area where we operate;

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Utilize derivative contracts to mitigate the impact of oil, NGL or natural gas price volatility, while locking in acceptable cash flows required to support future capital expenditures; and

Attract and retain the best people.

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 from resource plays in our core areas of operation where we can capitalize on our operating expertise. For 2015, we plan to allocate substantially all of our drilling and completions capital budget to development activities in the Mississippian area, based on the relatively stronger economic returns expected from these assets in the current commodity price and cost environment.

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, 2014, we had approximately 99,100 gross (79,000 net) acres under lease in the area, comprised of approximately 78,100 gross (66,300 net) leased acres in the Mississippian Lime and approximately 21,000 gross (12,700 net) acres in the Hunton. As of December 31, 2014, we had six drilling rigs in operation, and we currently have four drilling rigs in operation. We expect to spud between 58 to 64 gross (46 to 52 net) horizontal wells, including non-operated wells, during 2015 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. We target the Cleveland, Marmaton, Cottage Grove and Tonkawa formations in the Anadarko Basin by utilizing horizontal wells and multi-stage frac technology. At December 31, 2014, we had approximately 161,500 gross (122,600 net) acres under lease in the Anadarko Basin, comprised of approximately 44,100 gross (32,300 net) leased acres in Oklahoma and approximately 117,400 gross (90,300 net) acres in the Texas. As of December 31, 2014, we did not have any drilling rigs in operation in this area. In the current price environment, we do not expect to spud any wells on this acreage during 2015. We intend to continue to evaluate this prospective acreage for future drilling plans if commodity prices continue to decline and/or drilling and completion costs experience sustained improvement.

Gulf Coast. At December 31, 2014 we had approximately 68,200 gross (50,600 net) acres under lease and/or lease option. 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 Parish, Louisiana to a private buyer. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres and closed on May 1, 2014. On June 25, 2014, we entered into an exploration agreement with PetroQuest Energy ("PetroQuest") to sell 50% of our ownership interest in the Fleetwood prospect area in Louisiana. During 2015, we plan to participate with PetroQuest and other owners in the joint exploration and development of the Fleetwood area in Iberville, Point Coupee, and West Baton Rouge Parish, Louisiana. We executed a PSA in March 2015 for the sale of our Dequincy assets, our only remaining producing properties in Louisiana, for total consideration of $44 million (subject to customary purchase price adjustments). The PSA includes our ownership interest in developed and undeveloped acreage totaling approximately 12,700 net mineral acres in the Dequincy area. During the fourth quarter 2014, the properties produced approximately 1,300 Boe per day. The

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transaction does not include our acreage and interests in the Fleetwood area of Louisiana. The net proceeds from the sale will be used to pay down a portion of the outstanding borrowings under our revolving credit facility and for general corporate purposes. The transaction has an effective date of March 1, 2015 and is expected to close on or before April 30, 2015, subject to customary closing conditions. In the last year, we have shifted capital from the Gulf Coast area and as of December 31, 2014 we did not have any operated rigs active in the area. Our intent is to continue high grading inventory in Louisiana for future capital deployment. Other than the Fleetwood project, we expect limited development activity in the Gulf Coast area in 2015 as we continue focusing on the development of our Mississippian assets.

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, 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.

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.

Extensive technical knowledge in our areas of operations. In our Mississippian Lime area, we believe our team's early experience operating in this trend gives us a competitive advantage with respect to geological understanding, drilling and completion techniques and infrastructure development. In the Anadarko Basin area, that we have a history of drilling horizontally in several of the Pennsylvanian sands since 2005. 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 and ability to optimize production from these properties. 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.

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Summary of Oil and Gas Properties and Operations

Mississippian Lime

At December 31, 2014, our Mississippian Lime assets consisted of approximately 66,300 net prospective acres in the Mississippian Lime trend, with 64,100 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 12,700 net acres in Lincoln County, Oklahoma, which produces from, and is prospective in, the Hunton formation.

Our properties in this area represented 90% of our total proved reserves as of December 31, 2014. As of December 31, 2014, we held an average working interest and average net revenue interest of 69% and 55%, respectively, in this area.

For the three months ended December 31, 2014 and 2013 and the years ended December 31, 2014 and 2013, our average daily production from this area was as follows:

	Three Months Ended December 31,			Years Ended December 31,		
	2014	2013	Increase in Production	2014	2013	Increase in Production
Average daily production:						
Oil (Bbls)	10,060	6,325	59%	8,411	4,567	84%
Natural gas liquids (Bbls)	4,809	3,622	33%	4,437	2,620	69%
Natural gas (Mcf)	61,025	45,794	33%	52,024	34,784	50%
Net Boe/day	25,039	17,579	42%	21,518	12,985	66%

During 2014, we invested approximately $383.2 million and spud 76 net horizontal wells in this region. In the three months ended December 31, 2014, we spud 16 net wells and brought 24 net wells online. Of the 16 net wells spud during the quarter, three were drilling, 10 were awaiting completion and three were producing at year-end.

Our main operating area in the Mississippian Lime 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 drilling and completion techniques to determine the most cost effective design in this area.

In 2015, we plan to invest approximately $250 million to $275 million in the spudding of between 58 to 64 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 Lime

The majority of our rigs currently operating in the Mississippian Lime are focused on infill drilling in our core area; during 2015, we plan to drill four to six wells to extend our de-risked acreage to the west and hold acreage.

Anadarko Basin

Our Anadarko Basin assets were acquired on May 31, 2013, and at December 31, 2014, consisted of approximately 122,600 net acres in the Anadarko Basin, with 90,300 net acres in Texas and 32,300 net acres in western Oklahoma. We took over operation of the properties on December 1, 2013. As of December 31, 2014, we did not have any drilling rigs in operation in this area.

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Our properties in this area represented 8% of our total proved reserves as of December 31, 2014. As of December 31, 2014, we held an average working interest and average net revenue interest of 66% and 52%, respectively, in this area.

For the three months ended December 31, 2014 and 2013 and the years ended December 31, 2014 and 2013, our average daily production from this area was as follows:

	Three Months Ended December 31,			Years Ended December 31,		
	2014	**2013**	**Decrease in Production**	**2014**	**2013(1)**	**Increase in Production**
Average daily production:						
Oil (Bbls)	3,343	3,940	(15)%	4,014	2,239	79%
Natural gas liquids (Bbls)	1,703	1,816	(6)%	1,766	1,082	63%
Natural gas (Mcf)	13,749	16,190	(15)%	14,930	9,559	56%
Net Boe/day	7,337	8,454	(13)%	8,269	4,914	68%

(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.

During 2014, we invested approximately $139.8 million and spud 26 net horizontal wells in the area. In the three months ended December 31, 2014, we spud three net wells and brought two net wells online. Of the three net wells spud during the quarter, two were awaiting completion and one was producing at year-end. Since year-end, three wells have been completed and brought online.

In the current commodity price and drilling and completion cost environment, we do not currently plan to spud any wells on this acreage during 2015, however we will continue to evaluate for opportunities. For 2015, our efforts will focus on reducing well maintenance costs and production downtime and these efforts alone will not be sufficient to arrest the natural decline in production that occurs as we deplete our developed reserves. Additionally, because of our limited capital resources, we may allow leasehold rights on acreage not held by production to expire, which could reduce our future drilling opportunities in this area.

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, 2014, we had including acreage in the Fleetwood area, approximately 50,600 net acres in the trend under lease and/or lease option.

We closed on the sale of producing properties and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana on May 1, 2014 for estimated net proceeds of $147.5 million in cash, after post-closing adjustments. The sale has an effective date of November 1, 2013. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and did 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 626 and 3,453 Boe/d during the years ended December 31, 2014 and 2013, respectively, and 2,366 Boe/d during the quarter ended December 31, 2013. There was no production from Pine Prairie during the quarter ended December 31, 2014. Our remaining Gulf Coast areas of operation are concentrated in the South Bearhead and North Coward's Gully fields.

On June 25, 2014, we entered into an exploration agreement with PetroQuest to sell 50% of our ownership interest in the Fleetwood prospect area in Louisiana. We plan to participate with PetroQuest

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and other owners in the joint exploration and development of the Fleetwood area in Iberville, Point Coupee, and West Baton Rouge Parish, Louisiana. There are currently three wells planned to be spud in the first six months of the year; we will have a carried working interest ranging from 25% to 50% in those wells. The carried working interest is capped at a total credit of $14 million.

In March 2015, we executed a PSA for the sale of our Dequincy assets, our only remaining producing properties in Louisiana, for total consideration of $44 million (subject to customary purchase price adjustments). The PSA includes our ownership interest in developed and undeveloped acreage totaling approximately 12,700 net mineral acres in the Dequincy area. During the fourth quarter 2014, the properties produced approximately 1,300 Boe per day. The transaction does not include our acreage and interests in the Fleetwood area of Louisiana. The net proceeds from the sale will be used to pay down a portion of the outstanding borrowings under our revolving credit facility and for general corporate purposes. The transaction has an effective date of March 1, 2015 and is expected to close on or before April 30, 2015, subject to customary closing conditions.

Our properties in this area represented 2% of our total proved reserves as of December 31, 2014. As of December 31, 2014, we held an average working interest and average net revenue interest of 96% and 75%; respectively, in this area.

For the quarter ended December 31, 2014 and 2013, and years ended December 31, 2014 and 2013, our average daily production from the area was as follows:

	Three Months Ended December 31,			Years Ended December 31,		
	2014(1)	2013	Decrease in Production	2014(1)	2013	Decrease in Production
Average daily production:						
Oil (Bbls)	959	3,375	(72)%	1,669	3,890	(57)%
Natural gas liquids (Bbls)	278	995	(72)%	419	1,008	(58)%
Natural gas (Mcf)	911	4,706	(81)%	1,574	6,772	(77)%
Net Boe/day	1,388	5,154	(73)%	2,350	6,027	(61)%

(1) Note that as the Pine Prairie Disposition closed on May 1, 2014, this represents the majority of the impact to average annual production for the period of January 1, 2014 through May 1, 2014.

In the last year, we have shifted capital to the Mississippian Lime assets and as of December 31, 2014 did not have any rigs in operation in the Gulf Coast. Our intent is to continue high grading inventory in Louisiana for future capital deployment. Other than the Fleetwood area, we expect limited activity as we continue focusing on our Mississippian assets. We currently have no drilling rigs operating in this area as we have devoted our capital to developing our Mississippian Lime assets; however, we plan to continue to evaluate our acreage as well as other potential exploration opportunities in the Gulf Coast area. Because of our limited activity in this area, our production will continue to decline as we deplete our developed reserves.

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Estimated Proved Reserves

	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Total (MBoe)
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
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
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
2014				
Proved Reserves				
Beginning Balance	54,899	26,156	280,198	127,755
Revision of previous estimates	(11,563)	(4,444)	(41,510)	(22,925)
Extensions, discoveries and other additions	30,232	15,414	188,336	77,035
Sales of reserves in place	(10,182)	(2,181)	(24,166)	(16,391)
Production	(5,144)	(2,417)	(25,013)	(11,730)
Net proved reserves at December 31, 2014	**58,242**	**32,528**	**377,845**	**153,744**
Proved developed reserves, December 31, 2014	27,181	16,443	179,972	73,620
Proved undeveloped reserves, December 31, 2014	31,061	16,085	197,873	80,124

Our proved reserves have grown from 75.5 to 127.8 MMBoe from year end 2012 to year end 2013 and from 127.8 to 153.7 MMBoe from year end 2013 to year end 2014. 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 79% from 995 Boe/d in the year ended December 31, 2008 to 32,137 Boe/d in the year ended December 31, 2014.

Our proved developed reserves have increased 24.9 MMBoe from 48.7 MMBoe (or 38% of total reserves) to 73.6 (or 48% of total reserves) as a result of our drilling activities. Our proved undeveloped reserves have grown from 79.0 MMBoe to 80.1 MMBoe from December 31, 2013 to December 31, 2014. During this time, we spent $237 million of our capital expenditures on drilling proved undeveloped locations and converted 14.9 MMBoe from proved undeveloped reserves to proved developed reserves. In addition, we added 77.0 MMBoe of proved undeveloped reserves through extensions and discoveries and had net negative revisions of 22.9 MMBoe related to proved

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undeveloped reserves, of which 3.1 MMBoe related to reductions at our Gulf Coast area and 22.1 MMBoe related to reductions in our Anadarko Basin area, offset by 2.3 MMBoe in positive revisions in the Mississippian Lime area. These net negative revisions in the Gulf Coast were primarily due to our lack of future development plans in this area. The net negative revisions in the Anadarko Basin were primarily due to our current drilling plans which did not allow for development of these proved undeveloped reserves within five years of their initial booking.

In addition, 16.4 MMBoe of reserves were sold as a result of the Pine Prairie Disposition, which closed on May 1, 2014.

All of our proved undeveloped reserves as of December 31, 2014 are expected to be developed within five years of their initial booking.

Independent petroleum engineers

Mississippian Lime, Anadarko, and Gulf Coast Area Reserves

For our Mississippian Lime and Anadarko area, our estimated reserves and related future net revenues at December 31, 2014 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. 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 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 27 years of practical experience in petroleum engineering, with over 25 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.

Our estimated reserves and related future net revenues for the Mississippian Lime area at December 31, 2013 and 2012 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.

Our estimated reserves and related future net revenues at December 31, 2014 for the Gulf Coast area 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 the Gulf Coast area at December 31, 2013 and 2012 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.

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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, a Licensed Professional Engineer in the State of Texas (No. 71656), has been practicing consulting petroleum engineering at NSAI since 1989 and has over 6 years of prior industry experience. He graduated from Purdue University in 1983 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Hodgson, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 1314), has been practicing consulting petroleum geoscience at NSAI since 1998 and has over 14 years of prior industry experience. He graduated from 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. Both 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; both 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.

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, land 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, 2014, Mick Matejka, our Director Corporate Reserves, was the technical person primarily responsible for overseeing the preparation of our reserve estimates and reported directly to the CEO. Mr. Matejka has over 15 years of experience in the estimation and evaluation of oil and gas assets. Mr. Matejka started his career with Royal Dutch Shell working as a reservoir engineer for various asset teams in the Gulf of Mexico and the Lower 48, and eventually as exploration portfolio manager. Prior to joining Midstates Petroleum in 2012, Mr. Matejka had been a Sr. District engineer with Samson Resources, responsible for the evaluation of Samson's Haynesville shale asset. At Midstates Mr. Matejka headed the engineering evaluation of both the Eagle Energy and Panther Energy acquisitions, prior to transitioning into the role of Director Corporate Reserves. Mr. Matejka graduated from the University of Leoben, Austria as Diplom Ingenieur in Petroleum Business in 1998 and from the University of Oklahoma in 2001 with a Master of Science Degree in Petroleum Engineering. Furthermore Mr. Matejka holds an MBA from Heriot-Watt University, UK. 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, 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 for the year ended December 31, 2013, 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. During the year ended December 31, 2014, we have made changes in our internal control over financial reporting (specifically over the preparation of oil and gas reserve estimates) that have materially affected our internal control over financial reporting. For the year ended December 31, 2014, management concluded that the material weakness over the preparation of oil and gas reserve estimates (previously identified during the year ended December 31, 2013) had been remediated and that the Company maintained effective internal control over the accuracy and valuation of the oil and gas 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 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 and the price of natural gas has remained relatively depressed due to increasing supplies from shale plays. Additionally, the price of oil substantially declined in the fourth quarter of 2014 due to a variety of macro economic factors, including increasing supply, strengthening of the US dollar and forecasts of slower worldwide economic growth. Commodity prices have varied substantially over the past year. The spot natural gas prices during 2014 ranged from a high of $8.15 to a low of $2.99 per MMBtu and the spot oil prices during 2014 ranged from a high of $107.95 to a low of $53.45 per Bbl. Thus far in 2015, commodity prices have continued to be depressed and volatile, with spot natural gas prices ranging from a high of $3.32 to a low of $2.62 per MMBtu and the spot oil prices ranging from a high of $53.56 to a low of $44.08 per Bbl through March 2, 2015. Demand is impacted by general economic conditions, weather and other seasonal conditions. 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

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the future. A continued 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, NGLs and natural gas production, revenues and realized prices and production costs for the years ended December 31, 2014, 2013 and 2012. 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,		
	2014	**2013**	**2012**
Operating Data:			
Net production volumes:			
Oil (MBbls)	5,144	3,904	2,093
NGLs (MBbls)	2,417	1,719	617
Natural gas (MMcf)	25,013	18,657	5,695
Total oil equivalents (MBoe)	11,730	8,733	3,659
Average daily production (Boe/d)	32,137	23,927	9,999
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$ 90.71	$ 99.18	$ 104.35
Oil, with realized derivatives (per Bbl)	$ 87.40	$ 93.41	$ 95.05
Natural gas liquids, without realized derivatives (per Bbl)	$ 36.31	$ 36.26	$ 38.27
Natural gas liquids, with realized derivatives (per Bbl)	$ 36.40	$ 37.09	$ 40.48
Natural gas, without realized derivatives (per Mcf)	$ 3.97	$ 3.39	$ 2.81
Natural gas, with realized derivatives (per Mcf)	$ 3.91	$ 3.58	$ 3.21
Costs and Expenses (per Boe of production):			
Lease operating and workover	$ 6.79	$ 8.41	$ 8.34
Gathering and transportation	$ 1.14	$ 0.62	$
Severance and other taxes	$ 2.07	$ 3.12	$ 6.81
Asset retirement accretion	$ 0.15	$ 0.17	$ 0.20
Depreciation, depletion and amortization	$ 23.01	$ 28.67	$ 34.32
Impairment of oil and gas properties	$ 7.37	$ 51.91	$
General and administrative	$ 4.15	$ 6.10	$ 8.35
Acquisition and transaction costs	$ 0.35	$ 1.35	$ 4.07
Other	$ 0.44	$ 0.07	$

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The following table sets forth information regarding oil, NGLs and natural gas daily production for each of the fields that represented more than 15% of our estimated total proved reserves as of December 31, 2014:

	Years Ended December 31,		
	2014	**2013**	**2012**
Mississippian(1)			
Daily production volumes:			
Oil (Bbls)	8,401	4,550	203
NGLs (Bbls)	4,093	1,908	123
Natural gas (Mcf)	50,164	30,070	1,289
Total oil equivalents (Net Boe/day)	**20,854**	**11,470**	**541**
Anadarko(2)			
Daily production volumes:			
Oil (Bbls)	4,014	2,239	
NGLs (Bbls)	1,766	1,082	
Natural gas (Mcf)	14,930	9,559	
Total oil equivalents (Net Boe/day)	**8,269**	**4,914**	

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

(2) Anadarko production volumes for 2013 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, 2014:

	Oil		Natural Gas		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Total productive wells	611	417	54	40	665	457

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, 2014 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 Lime	82,778	65,627	16,299	13,390	99,077	79,017
Anadarko Basin	118,386	95,306	43,092	27,294	161,478	122,600

Gulf Coast	10,785	10,783	57,375	39,796	68,160	50,579
Total	**211,949**	**171,716**	**116,766**	**80,480**	**328,715**	**252,196**

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Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2014 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 2015		Expiring 2016		Expiring 2017	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Mississippian Lime	3,300	2,385	7,970	6,911	3,473	3,021
Anadarko Basin	17,235	10,917	9,984	6,324	15,846	10,032
Gulf Coast	15,880	14,958	16,525	11,206	13,484	8,483
Total Undeveloped Acreage Expirations	**36,415**	**28,260**	**34,479**	**24,411**	**32,803**	**21,536**

Approximately 6% of our net acreage, including acreage under option, was acquired in 2014, 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. Because of our limited capital resources and reduced activity levels in the Anadarko Basin and Gulf Coast, we may allow leasehold rights on acreage not held by production to expire in these areas, which could reduce our future drilling opportunities. Based on current pricing and current drilling plans, we impaired the remaining Anadarko basin unevaluated property to the full cost pool during the fourth quarter of 2014.

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2014, 2013 and 2012. 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,					
	2014		**2013**		**2012**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development wells:						
Productive	119	97	121	98	68	64
Dry holes			1	1	7	7
Total	**119**	**97**	**122**	**99**	**75**	**71**
Exploratory wells:						
Productive	1	1			4	3
Dry holes			2	2		
Total	**1**	**1**	**2**	**2**	**4**	**3**
Total wells	**120**	**98**	**124**	**101**	**79**	**74**

As of December 31, 2014, there were four gross (and net) development wells currently drilling; no exploratory wells were being drilled.

After peaking in 2013, our drilling activity has decreased over the last several months. At December 31, 2014 we were operating six drilling rigs on our properties and we are currently operating four drilling rigs. 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. For the year ended December 31, 2014, we did not have any operated wells that were deemed dry holes. However, as part

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of our exploration agreement with PetroQuest (discussed above), one well was drilled and deemed a dry hole in the Lower Wilcox during the first quarter of 2015.

Marketing and Major Customers

We sell our oil, NGLs 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, 2014, Plains Marketing, Semgas, Phillips66 and Valero Marketing accounted for 28%, 18%, 15% and 12% of our revenues, respectively. 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. 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.

We are party to a gas purchase, gathering and processing contract (as amended and effective June 1, 2013) in the Mississippian Lime region, which includes certain minimum natural gas and NGL volume commitments. To the extent we do not deliver natural gas volumes in sufficient quantities to generate, when processed, the minimum levels of recovered NGLs, we would be required to reimburse the counterparty an amount equal to the sum of the monthly shortfall, if any, multiplied by a fee of roughly $0.08 to $0.125 per gallon (subject to annual escalation). The NGL volume commitments range from 2,800 Bbls to 5,780 Bbls per day for each monthly accounting period over the remaining term of the contract. Additionally, we are obligated to deliver a total of 38,100,000 MMBtus and 76,200,000 MMBtus during the first 30 months and 60 months of the contract, respectively. During the first 30 months, any shortfall in delivered volumes would result in a payment to the counterparty equal to the shortfall amount multiplied by a fee of approximately $0.36 per MMBtu. During the first 60 months, any shortfall in delivered volumes would result in a payment to the counterparty equal to the shortfall amount multiplied by a fee of approximately $0.36 per MMBtu, provided that we would receive volumetric credit for any deficiency payment made after the initial 30 months. As of January 31, 2015, we have delivered 62,573,054 MMBtu. We are currently delivering at least the minimum volumes required under these contractual provisions and do not expect to incur any future volumetric shortfall payments during the term of this contract.

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.

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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 increased costs or delay or temporarily halt our operations.

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

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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 NGLs 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.

The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach that FERC has historically maintained 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 to the anti-market manipulation laws, FERC has also issued regulations to increase market transparency. 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 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 and natural gas marketers, to report on May 1 of each year aggregate volumes

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of natural gas purchased or sold at wholesale in the previous 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 transactions should be reported based on the guidance of Order No. 704.

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 NGLs 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,

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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, 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.

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.

In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission ("CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude purchases and sales. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1 million or triple the monetary gain to the person for each violation.

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;

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(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 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, and occupational 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 and nonhazardous 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 RCRA nonhazardous wastes. In addition, we generate petroleum hydrocarbon wastes and ordinary industrial wastes in the course of our operations that may become regulated as RCRA 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 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, that certain of the natural gas wells being fractured or re-fractured must use reduced emission completions, also known as "green completions," with or without combustion devices, beginning in January 2015. These regulations also establish specific requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. In a more recent example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015 that would revise the National Ambient Air Quality Standard for ozone, recommending a standard between 65 to 70 parts per billion ("ppb") for both the 8-hour primary and secondary standards protective of public health and public welfare. If the EPA lowers the ozone standard, states could be required to implement more stringent regulations, which could, among other things, require installation of new emission controls on some of the drilling program's equipment, result in longer permitting timelines, and significantly increase the partnership's capital expenditures and drilling program's operating costs, which could adversely impact our business. Compliance with any one or more of these requirements could increase our costs of development and production, which costs could be significant.

Climate change

Based on the EPA's determination that emissions of carbon dioxide, methane and other greenhouse gases ("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, the agency has adopted regulations under existing provisions of the federal CAA that, among other things, establish pre-construction and operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain permits for their GHG emissions also will be required to meet "best available control technology" standards that typically will be established by the states. In addition, the EPA has adopted regulations requiring the monitoring and annual reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities, 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. These EPA regulations 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. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. 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, pay fees on the emissions data, and adversely affect demand for the oil and natural gas that we produce. For example, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. 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 and fluid injections

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 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.

Fluids resulting from oil and natural gas production, consisting primarily of salt water, are disposed by injection in belowground disposal wells. These disposal wells are regulated pursuant to the Underground Injection Control ("UIC") program established under the federal Safe Drinking Water Act and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. While we believe that our disposal well operations substantially comply with requirements under the UIC program, a change in disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect our ability to dispose of salt water and ultimately increase the cost of our operations. For example, there exists a growing concern that the injection of saltwater and other fluids into belowground disposal wells triggers seismic activity in certain areas, including Texas and Oklahoma, where we operate. In response to these concerns, in October 2014, the Texas Railroad Commission ("TRC") published a final rule governing permitting or re-permitting of disposal wells that will require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. These new seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and likely to result in added costs to comply or, perhaps, may require alternative methods of disposing of salt water and other fluids, which could delay production schedules and also result in increased costs. Similar rules may be expected to be promulgated by the Oklahoma Corporation Commission (OCC). The OCC recently posted a guidance for wells injecting into the Arbuckle formation. OCC is watching for indications that salt water injection may be contributing to significant seismic events and has recently temporarily shut in another Producer's water disposal well due to a nearby 4.0 magnitude earthquake.

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

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fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management ("BLM") issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015. 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, as amended ("SDWA") 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. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. 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 are underway that focus on environmental aspects of hydraulic fracturing practices. For example, 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 and is expected to issue a draft report for public comment and peer review sometime in the first half of 2015. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA 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. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act. 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 in 2011, the U.S. Fish and Wildlife Service ("FWS") is required to make a determination on a listing of species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. For example, in March 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Texas and Oklahoma, where we conduct operations, as a threatened species under the ESA. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies ("WAFWA"), pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. The designation of the lesser prairie chicken or other previously unprotected species as endangered or threatened in areas where underlying operations are conducted or, alternatively, entry into certain range-wide conservation planning agreements such as WAFWA, could result in increased costs to us from species protection measures, time delays or limitations on our ability to develop and produce reserves, which costs, delays or limitations may be significant.

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, 2014, we employed 183 people, including 42 technical (geosciences, engineering, land), 76 field operations, 59 corporate (finance, accounting, planning, business development, legal, office management) and six management.

Offices

We currently lease approximately 57,000 square feet of office space in Tulsa, Oklahoma at 321 South Boston Avenue, Suite 1000, where our principal offices are located. The lease for our Tulsa office expires in 2021. We also lease approximately 41,200 square feet of office space in Houston, Texas at 4400 Post Oak Parkway, Suite 2600. The lease for our Houston office expires in 2018. Due to the announced closure of our Houston office, we are currently working to sublet our Houston office space. We also lease one field office in Louisiana, one in Dacoma, Oklahoma and one in Perryton, Texas.

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 NYSE 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 321 Boston Avenue, Suite 1000; Tulsa, Oklahoma 74103, attention Vice President, Legal. 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

Due to reduced commodity prices and lower operating cash flows, coupled with substantial interest payments, there is doubt about our ability to maintain adequate liquidity through 2015 and our ability to make interest payments in respect of our indebtedness.

During the second half of 2014, NYMEX-WTI oil prices fell from in excess of $100 per Bbl to below $50 per Bbl, the lowest price since 2009. The substantial reduction in oil and NGL prices has caused a reduction in our forecast of available liquidity and we may not have the ability to maintain our current borrowing base under our reserve based credit facility at its current levels or generate sufficient cash flows from operations and, therefore, sufficient liquidity to meet our anticipated working capital, debt service and other liquidity needs. As of December 31, 2014, we had available cash of approximately $11 million and availability under our reserve based revolving credit facility of approximately $90 million. As of December 31, 2014, payments due on our contractual obligations during the next twelve months were approximately $150 million. This includes approximately $130 million of interest payments on our senior notes and other operating expenses such as fixed drilling commitments and operating leases. We believe that our forecasted cash and available credit capacity are not expected to be sufficient to meet our commitments as they come due over the next twelve months and that we will not be able to remain in compliance with our debt covenants unless we are able to successfully increase our liquidity. A sustained material decline in oil, NGL and natural gas prices or a reduction in our oil and natural gas production and reserves would reduce our ability to fund our capital expenditure program and negatively impact our liquidity on an ongoing basis. We expect we will need to complete certain transactions, including management of our debt capital structure and potential asset sales, to have sufficient liquidity to satisfy these obligations in the long-term.

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We are currently evaluating strategic alternatives to address our liquidity issues and high debt levels. We cannot assure you that any of these efforts will be successful or will result in cost reductions or additional cash flows or the timing of any such cost reductions or additional cash flows. We are currently reviewing our alternatives and may adopt other strategies that may include actions such as a refinancing or restructuring of our indebtedness or capital structure, reducing or delaying capital investments or seeking to raise additional capital through debt or equity financing. We cannot assure you that any refinancing or debt or equity restructuring would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all. Furthermore, we cannot assure you that any of our strategies will yield sufficient funds to meet our working capital or other liquidity needs, including for payments of interest and principal on our debt in the future, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations.

Our substantial indebtedness, liquidity issues and potential to seek restructuring transactions may have a material adverse effect on our business and operations.

Our substantial indebtedness, liquidity issues and potential to seek restructuring transactions may result in uncertainty about our business and cause, among other things:

- third parties' to lose confidence in our ability to explore and produce oil and natural gas, resulting in a significant decline in our revenues, profitability and cash flow;
- difficulty retaining, attracting or replacing key employees;
- employees to be distracted from performance of their duties or more easily attracted to other career opportunities; and
- our suppliers, vendors, hedge counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us.

These events may have a material adverse effect on our business and operations.

If we are unable to repay or refinance our existing and future debt as it becomes due, we may be unable to continue as a going concern.

Our existing and future debt agreements could create issues as interest payments become due and the debt matures that will threaten our ability to continue as a going concern. For example, absent any action with respect to the repayment or refinancing of our existing indebtedness or any waivers or amendments to the agreements governing our existing indebtedness, our reserve based revolving credit facility is scheduled to mature in 2018 and our senior notes are scheduled to mature in 2020 and 2021. Additionally, the borrowing base under our reserve based revolving credit facility is subject to at least semi-annual redetermination and as a result, availability thereunder could be reduced and advances in excess of the new availability would need to be repaid. We have substantial interest payments due during the next twelve months, including approximately $130 million of total interest payments due on our senior notes in 2015. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the revolving credit facility, the indentures governing our senior notes, or other agreements governing our indebtedness, an event of default could result, which would permit acceleration of such debt and which could result in an event of default under and acceleration of our other debt and could permit our secured lenders to foreclose on any of our assets securing such debt. Any accelerated debt would become immediately due and payable. While we will attempt to take appropriate mitigating actions to refinance any indebtedness prior to its maturity or otherwise extend the maturity dates, and to cure any potential defaults, there is no assurance that any particular actions with respect to refinancing existing indebtedness, extending the maturity of existing indebtedness or curing potential defaults in our existing and future debt agreements will be sufficient.

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The consolidated financial statements included in this Annual Report on Form 10-K have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern.

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. The spot natural gas prices during 2014 ranged from a high of $8.15 to a low of $2.99 per MMBtu and the spot oil prices during 2014 ranged from a high of $107.95 to a low of $53.45 per Bbl. Thus far in 2015, commodity prices have continued to be depressed and volatile, with spot natural gas prices ranging from a high of $3.32 to a low of $2.62 per MMBtu and the spot oil prices ranging from a high of $53.56 to a low of $44.08 per Bbl through March 2, 2015. 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;
- 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.

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We may not be able to obtain funding under our revolving credit facility because of a decrease in our borrowing base or obtain funding in the capital markets on terms we find acceptable.

Historically, we have used our cash flows from operations and borrowings under our revolving credit facility to fund our capital expenditures and have relied on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions or to refinance debt obligations. As of December 31, 2014, we have a revolving credit facility with $90 million available and a borrowing base of $525 million. The borrowing base under our revolving credit facility is subject to semiannual redeterminations in April and October and up to one additional time per six month period following each scheduled borrowing base redetermination, as may be requested by us or the administrative agent, acting on behalf of lenders holding at least two-thirds of the outstanding loans and other obligations. The next scheduled borrowing base redetermination date is April 1, 2015. Should prices for oil and natural gas remain weak or deteriorate, if we have a downward revision in estimates of our proved reserves, or if we sell oil and natural gas reserves, our borrowing base may be reduced. Any reduction in the borrowing base will reduce our available liquidity, and, if the reduction results in the outstanding amount under the facility exceeding the borrowing base, we will be required to repay the deficiency within 30 days or in six equal monthly installments thereafter, at our election. We may not have the financial resources in the future to make any mandatory deficiency principal prepayments required under our revolving credit facility, which could result in an event of default.

In the future, we may not be able to access adequate funding under our revolving credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. Since the process for determining the borrowing base under our revolving credit facility involves evaluating the estimated value of some of our oil and natural gas properties using pricing models determined by the lenders at that time, a decline in those prices used, or further downward reductions of our reserves, likely will result in a redetermination of our borrowing base and a decrease in the available borrowing amount at the time of the next scheduled redetermination. In such case, we would be required to repay any indebtedness in excess of the borrowing base.

Volatility in the public and private capital markets may make it more difficult to obtain funding. There is a risk that the cost of obtaining money from the credit markets may increase in the future as lenders and institutional investors may increase interest rates, impose tighter lending standards, refuse to refinance existing debt at maturity on terms similar to existing debt or at all, or reduce or cease to provide any new funding. Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Our ability to access funds under our revolving credit facility is based on a borrowing base, which is subject to periodic redeterminations based on our proved reserves and commodity prices that will be determined by our lenders using the bank pricing prevailing at such time.

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

As of December 31, 2014, we had $90 million available and a borrowing base of $525 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.

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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.

In addition, our revolving credit facility requires us to maintain certain financial ratios, including a leverage ratio. All of these restrictive covenants may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our revolving credit facility may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our revolving credit facility, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our revolving credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our revolving credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

We may be unable to maintain compliance with certain financial ratio covenants of our outstanding indebtedness which could result in an event of default that, if not cured or waived, would have a material adverse effect on our business, financial condition and results of operations.

Our revolving credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. As of December 31, 2014, our ratio of net consolidated indebtedness to EBITDA was 3.7:1.0 and our ratio of current assets to current liabilities was 1.1:1.0. If liquidity concerns are not addressed in the near-term, we may breach the leverage covenant of our revolving credit facility which currently requires a maximum ratio of net consolidated indebtedness to EBITDA of 4.0:1.0 beginning with the first quarter of 2015. As of December 31, 2014, we are in compliance with our financial covenants; however, we cannot guarantee that we will be able to comply with such terms at all times in the future. Any failure to comply with the conditions and

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covenants in our revolving credit facility that is not waived by our lenders or otherwise cured could lead to a termination of our revolving credit facility, acceleration of all amounts due under our revolving credit facility, or trigger cross-default provisions under other financing arrangements. These restrictions may limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our indebtedness impose on us.

Liquidity concerns could result in a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

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 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;

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- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.
- cost associated with developing and operating oil and gas properties

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. If the standardized measure of discounted future net cash flows was run at current strip prices, our total estimated proved reserves would be significantly below the standardized measure of discounted future net cash flows at December 31, 2014.

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, 2014, 2013 and 2012, 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 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.

Due to the recent decrease in oil and natural gas prices and if prices continue to 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

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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 March 31, 2014, we recognized an impairment of $86.5 million, 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 sustained or further decline in commodity prices.

Oil and natural gas prices are volatile. A substantial portion of our hedges are set to expire in 2015. If we choose not to replace hedges as those contracts expire, our cash flows from operations will be subjected to increased volatility.

We enter into hedging transactions of our oil and natural gas production revenues to reduce our exposure to fluctuations in the price of oil and natural gas. A substantial portion of our hedges are set to expire in 2015. As our hedges expire, more of our future production will be sold at market prices, exposing us to the fluctuations in the price of oil and natural gas, unless we enter into additional hedging transactions. We may choose not to replace existing hedges as those contracts expire, which will subject our cash flows from operations to increased volatility.

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 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 52% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2014. 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, pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. Accordingly, delays in the development of such reserves, increases in capital expenditures required to develop such reserves and changes in commodity prices could cause us to have to reclassify our proved undeveloped reserves as unproved reserves, which may materially adversely affect our business, results of operations and financial condition.

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.

Our business depends on the availability of water and the ability to dispose of water. Limitations or restrictions on our ability to obtain or dispose of water may have an adverse effect on our financial condition, results of operations and cash flows.

With current technology, water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water, or to dispose of or recycle water after use, could adversely impact our operations. In some cases, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Moreover, the introduction of new environmental initiatives and regulations related to water acquisition or waste water disposal, including produced water, drilling fluids and other wastes associated with the exploration, development or production of hydrocarbons, could limit or prohibit our ability to utilize hydraulic fracturing or waste water injection control wells.

In addition, concerns have been raised about the potential for earthquakes to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in our operations. We operate injection wells and utilize injection wells owned by third parties to dispose of waste water associated with our operations.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of water necessary for hydraulic fracturing of wells or the disposal of water may increase our operating costs or may cause us to delay, curtail or discontinue our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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, capacity constraints, 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.

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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.

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 unauthorized releases 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.

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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.

We are subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

We have previously acquired reserves, properties, prospects and leaseholds from third parties, including the Eagle Property Acquisition and the Anadarko Basin Acquisition. In addition, we will continue to evaluate other acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of assets and other producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
- validity of the sellers' title to the properties, which may be less than expected at the time of signing the purchase agreement; and
- potential environmental issues, litigation and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the sellers may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;

an inability to secure, on acceptable terms, sufficient financing that may be required in connection with expanded operations and unknown liabilities; and

the challenge of attracting and retaining personnel associated with acquired operations.

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The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

In addition, even if we successfully integrate operations acquired in acquisitions, we may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices in oil and natural gas industry conditions, risks and uncertainties relating to the exploratory prospects of the combined assets or operations, failure to retain key personnel, an increase in operating or other costs or other difficulties. We may experience additional challenges integrating the assets of privately operated companies. If we fail to realize the benefits we anticipate from an acquisition, our results of operations and stock price may be adversely affected.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

We are subject to credit risk due to concentration of our oil, NGL and natural gas receivables with several significant customers. The largest purchaser of our oil, NGL and natural gas during the year ended December 31, 2014 was Plains Marketing, L.P., accounting for 28%, and for the year ended December 31, 2013 the largest purchaser of was ConocoPhillips, accounting for 28% of our total revenues for these periods. Chevron accounted for 41% of our revenues for the year ended December 31, 2012. We generally do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition and results of operations.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil, we enter into derivative instruments for a portion of our oil, NGL and natural gas production. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk" and Note 5 to our Consolidated Financial Statements for a summary of our oil commodity derivative positions. We did not designate any of our derivative instruments as hedges for accounting purposes, and we record all derivative instruments in our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative instruments expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received for basis differentials.

In addition, our derivative arrangements limit the benefit we would receive from increases in the prices for oil, NGLs and natural gas.

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Large competitors may be attracted to our core operating areas, which may increase our costs.

Our operations in the Mississippian Lime formation in northwestern Oklahoma, the Anadarko Basin in Texas and Oklahoma and the Upper Gulf Coast tertiary trend in Louisiana may attract companies that have greater resources than we do. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Their presence in our areas of operations may also restrict our access to, or increase the cost of, oil and natural gas infrastructure, drilling rigs, equipment, supplies, personnel and oilfield services, including fracking equipment and crews. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See "Business Competition" for additional discussion of the competitive environment in which we operate.

The volatility in commodity prices and business performance may affect our ability to retain key management. The loss of senior management or technical personnel could adversely affect our operations.

We depend on the services of our senior management and technical personnel. In March 2014, John A. Crum resigned from the position of President, Chief Executive Officer and Chairman of the Board of Directors. Other members of our management team also resigned in 2014. Additionally, the volatility in commodity prices and business performance may affect our ability to retain key management. The loss of the services of additional members of our senior management or technical personnel could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. Furthermore, if we are unable to find, hire and retain needed key personnel in the future, our business, financial condition and results of operations could be materially and adversely affected.

Title to the properties in which we have an interest may be impaired by title defects.

We do not obtain title insurance and have not necessarily obtained drilling title opinions on all of our oil and natural gas properties. The existence of title deficiencies with respect to our oil and natural gas properties could reduce the value or render such properties worthless, which could have a material adverse effect on our business and financial results. A significant portion of our acreage is undeveloped leasehold acreage, which has a greater risk of title defects than developed acreage. Frequently, as a result of title examinations, certain curative work may be required to correct identified title defects, and such curative work entails time and expense. Our inability or failure to cure title defects could render some locations undrillable or cause us to lose our rights to some or all production from some of our oil and natural gas properties, which could have a material adverse effect on our business and financial results if a comparable additional location to drill a development well cannot be identified.

The proposed U.S. federal budget for fiscal year 2015 and proposed legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations and cash flows.

The Obama administration's budget proposals for fiscal year 2015 contains numerous proposed tax changes, and from time to time, legislation has been introduced that would enact many of these proposed changes. The proposed budget and legislation would repeal many tax incentives and deductions that are currently available to U.S. oil and gas companies. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling and development costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; and increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law our taxes could increase, potentially significantly, after net operating losses are exhausted, which would have a negative impact on our net income and cash flows and could reduce our drilling activities. We do not know the ultimate impact these proposed changes may have on our business.

We are subject to various governmental regulations that may cause us to incur substantial costs.

From time to time, in varying degrees, political developments and federal and state laws and regulations affect our operations. In particular, price controls, taxes and other laws relating to the oil and natural gas industry, changes in these laws and changes in administrative regulations have affected, and in the future could affect, oil and natural gas production, operations and economics. We cannot predict how agencies or courts will interpret existing laws and regulations or the effect of these adoptions and interpretations may have on our business or financial condition.

Our business is subject to laws and regulations promulgated by federal, state and local authorities relating to the exploration for, and the development, production and marketing of, oil and natural gas, as well as safety matters. Legal requirements are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government, and third parties and may require us to incur substantial costs of remediation.

Our sales of oil and gas may expose us to extensive regulation.

The FERC, the Commodity Futures Trading Commission and the Federal Trade Commission hold statutory authority to monitor certain segments of the physical energy commodities markets relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales, if any, of oil and gas, we are required to observe the market-related regulations enforced by these agencies.

Our operations are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration, production and development operations are subject to stringent and complex federal, regional, state and local laws and regulations governing the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling, completion and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, and impose substantial liabilities for pollution resulting from our operations. We may be required to make significant capital and operating expenditures to prevent releases, manage wastewater discharges and control air emissions or perform remedial or other corrective actions at our wells and properties to comply with the requirements of these environmental laws and regulations or the terms or conditions of permits issued pursuant to such requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, loss of our leases, incurrence of investigatory or remedial obligations and the issuance of orders limiting or prohibiting some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and other hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations and waste disposal practices at our leased and owned properties. Spills or other releases of regulated substances, including such spills and releases that occur in the future, could expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general in addition to our own results of operations, competitive position or financial condition. For example, in 2012, the EPA published final rules that subject certain oil and natural gas sources, including production operations, to regulation under the NSPS and NESHAP programs that, among other things, require performance of green completions on certain fractured and re-fractured natural gas wells and establish specific requirements regarding emissions from certain production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. In a more recent example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015 that would seek to reduce the National Ambient Air Quality Standard for ozone to between 65 and 70 ppb for both the 8-hour primary and secondary standards. Compliance with these or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our expenditures and operating costs, which could adversely impact our business. We may not be able to recover some or any of these costs from insurance.

Climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Based on the EPA's determination that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes, the EPA has regulations under existing provisions of the CAA that, among other things, establish pre-construction and operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain permits for their GHG emissions also will be required to meet "best available control technology" standards that typically will be established by the states. In addition, the EPA has adopted regulations requiring the monitoring and annual reporting of GHGs from certain sources in the United States, including, among others, certain onshore and offshore oil and natural gas production facilities.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs and a number of states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. For example, in January 2015, the Obama Administration announced plans for the EPA to issue final standards in 2016 that would reduce methane emissions from new and modified oil and natural gas production and natural gas processing and transmission facilities by up to 45 percent from 2012 levels by 2025. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. 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.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, which could adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely utilize hydraulic fracturing techniques in many of our oil and natural gas drilling and completion programs. The process is typically regulated by state oil and natural gas commissions or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

From time to time, Congress has considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Moreover, some states, including Louisiana, Texas and Oklahoma, where we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations under certain circumstances. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. In addition, local government 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. 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, and experience delays or curtailment in the pursuit of exploration, development, or production activities. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

In addition, there are also certain governmental reviews underway that focus on environmental aspects of hydraulic fracturing practices. For example, the White House Council on Environmental Quality is coordinating an administration wide review of hydraulic fracturing practices. Also, the EPA is pursuing a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and is expected to issue a draft report for public comment and peer review sometime in the first half of 2015. These existing or any future studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or otherwise.

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Our operations are dependent on our rights and ability to receive or renew the required permits and other approvals from governmental authorities and other third parties.

Performance of our operations require that we obtain and maintain numerous environmental and land use permits and other approvals authorizing our regulated activities. A decision by a governmental authority or other third party to deny, delay or restrictively condition the issuance of a new or renewed permit or other approval, or to revoke or substantially modify an existing permit or other approval, could have a material adverse effect on our ability to initiate or continue operations at the affected location or facility. Expansion of our existing operations is also predicated on securing the necessary environmental or land use permits and other approvals, which we may not receive in a timely manner or at all.

The enactment of derivatives legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for, or linked to, certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. In addition, the Dodd-Frank Act requires that regulators establish margin rules for uncleared swaps. Although we expect to qualify for the end-user exceptions to the mandatory clearing and margin requirements for swaps entered to hedge our commercial risks, the application of the requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging.

The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

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

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material adverse effect on our financial condition and results of operations.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

Risks Relating to our Common Stock

Because we are a relatively small company, the requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act of 2002, may strain our resources, increase our costs and divert management attention, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the NYSE. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We are required to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- involve and retain to a greater degree outside counsel and accountants in the above activities; and
- establish an investor relations function.

In addition, being a public company subject to these rules and regulations could require us, in the future, to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract new or additional qualified members to our board of directors, particularly to serve on our audit committee and compensation committee, and qualified executive officers.

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, your only opportunity to achieve a return on your investment is if the price of our common stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our revolving credit facility and the indentures governing our Senior Notes. Consequently, your only

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opportunity to achieve a return on your investment in us will be if you sell your common stock at a price greater than you paid for it.

We are currently controlled by First Reserve, and First Reserve and Riverstone collectively hold a majority of the voting power of our common stock and certain actions by us will require the consent of First Reserve or Riverstone. Their interests as equity holders may conflict with the interests of our other shareholders or our noteholders.

First Reserve currently owns an economic interest in us through FR Midstates Interholding LP ("FRMI"), which owns approximately 39% of our shares of common stock and is controlled by First Reserve. Eagle Energy, which is controlled by Riverstone Holdings, LLC ("Riverstone"), holds Series A Preferred Stock issued as consideration in the Eagle Property Acquisition. On a pro forma basis following conversion of the Series A Preferred Stock at a conversion price of $11.00, FRMI and Riverstone will own 26% and 33% of our shares of common stock, respectively.

While they hold these interests, these entities will have significant influence over our operations, will have representatives on our board of directors and have significant influence over all matters that require approval by our stockholders, including the approval of significant corporate transactions. This concentration of ownership will limit the ability of our stockholders to influence corporate matters, and as a result, actions may be taken that our shareholders may not view as beneficial.

In addition, we, FRMI and certain of our other stockholders have entered into a stockholders' agreement that permits FRMI to designate certain of our director nominees and prohibits us from engaging in certain transactions without the written consent of FRMI.

The stockholders' agreement provides that the following actions by us require the consent of FRMI:

- incurrence of debt that would result in a total net indebtedness to EBITDA ratio in excess of 2.50:1;
- authorization, creation or issuance of any equity securities (other than pursuant to compensation plans approved by the compensation committee or in connection with certain permitted acquisitions);
- redemption, acquisition or other purchase of any of our securities (other than certain repurchases from employees and directors);
- amendment, repeal or alteration of our amended and restated certificate of incorporation or amended and restated bylaws;
- any acquisition or disposition (where the amount of consideration exceeds $100 million in a single transaction or $200 million in any series of transactions during a calendar year);
- consummation of a "change in control" transaction;
- adoption, approval or issuance of any "poison pill" or similar rights plan; and
- entry into any plan of liquidation, dissolution or winding-up.

These actions by us require the consent of FRMI until the earlier of (i) receipt by our board of directors of FRMI's written election to waive its rights, (ii) the date FRMI ceases to hold at least 35% of our outstanding common stock, (iii) the third anniversary of the closing of our initial public offering or (iv) the date on which there are no directors nominated by FRMI serving as members of our board of directors.

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The terms of the Series A Preferred Stock permit Riverstone to designate one of our director nominees, who must be an employee of Riverstone or one of its affiliates, and prohibit us from engaging in certain transactions without the consent of Riverstone, including the following actions:

- the creation or issuance of any class of capital stock senior to or on parity with the Series A Preferred Stock;
- the redemption, acquisition or purchase by us of any of our equity securities, other than a repurchase from an employee or director in connection with such person's termination or as provided in the agreement pursuant to which such equity securities were issued;
- any change to our certificate of incorporation or bylaws that adversely affects the rights, preferences, privileges or voting rights of the holders of the Series A Preferred Stock;
- acquisitions or dispositions for which the amount of consideration exceeds 20% of our market capitalization in any single transaction or 40% of our market capitalization for any series of transactions during a calendar year;
- entering into certain transactions with affiliates, other than transactions that do not exceed, in the aggregate, $10 million in any calendar year;
- certain corporate transactions unless the holders of the Series A Preferred Stock would receive consideration consisting solely of cash and/or marketable securities with an aggregate fair market value equal to or greater than the liquidation preference on such shares of Series A Preferred Stock; and
- any increase or decrease in the size of our board of directors.

As a result of FRMI's and Riverstone's equity ownership or voting power, director nominees and consent rights, our ability to engage in financing transactions or other significant transactions, such as a merger, acquisition, disposition or liquidation, may be limited. In connection with such transactions, conflicts of interest could arise between us and FRMI or Riverstone, and any conflict of interest may be resolved in a manner that does not favor us.

Our amended and restated certificate of incorporation contains a provision renouncing our interest and expectancy in certain corporate opportunities, which could adversely affect our business or prospects.

Conflicts of interest could arise in the future between us, on the one hand, and First Reserve and its affiliates, including its portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. First Reserve is a private equity firm in the business of making investments in entities primarily in the global energy sector. As a result, First Reserve's existing and future portfolio companies which it controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

Our amended and restated certificate of incorporation provides that, to the fullest extent permitted by applicable law, we renounce any interest or expectancy in, or in being offered an opportunity to participate in, any business opportunity that may be from time to time presented to First Reserve or its affiliates or any of their respective officers, directors, agents, shareholders, members, partners, affiliates and subsidiaries (other than us and our subsidiaries) or business opportunities that such parties participate in or desire to participate in, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such person shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling stockholder or otherwise, by reason of the fact that such person pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us unless, in the case of any such person who is our director or officer, any such business opportunity is expressly offered to such director or officer solely in his or her capacity as our director or officer.

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As a result, First Reserve or its affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to First Reserve and its affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

We are a "controlled company" within the meaning of the NYSE rules and, as a result, qualify for exemptions from certain corporate governance requirements.

Riverstone, First Reserve and certain of our stockholders, including Stephen P. McDaniel (a former member of our Board of Directors) and members of our executive management team, collectively control a majority of the combined voting power of all classes of our outstanding voting stock and we are a "controlled company" within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a "controlled company" and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the nominating and corporate governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- there be an annual performance evaluation of the nominating and corporate governance and compensation committees.

These requirements will not apply to us as long as we remain a "controlled company." We may utilize some or all of these exemptions.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of December 31, 2014, we did not have any unresolved comments from the SEC staff that were received 180 or more days prior to year-end.

ITEM 2. PROPERTIES

Information regarding our properties is included in "Item 1. Business" above.

ITEM 3. LEGAL PROCEEDINGS

The information set forth under "Litigation" in Note 15 Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

None.

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PART II.

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market for Registrant's Common Equity.

Our common stock is listed on the New York Stock Exchange under the symbol "MPO."

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

	Price Range	
	High	**Low**
2013		
First Quarter	$ 8.95	$ 6.80
Second Quarter	$ 8.58	$ 5.31
Third Quarter	$ 6.55	$ 4.26
Fourth Quarter	$ 6.73	$ 4.79
2014		
First Quarter	$ 6.75	$ 4.13
Second Quarter	$ 7.50	$ 4.56
Third Quarter	$ 7.13	$ 5.05
Fourth Quarter	$ 5.26	$ 1.05
2015		
First Quarter(1)	$ 1.64	$ 0.96

(1) First quarter 2015 high and low ranges are calculated through March 3, 2015.

Holders.

The number of shareholders of record of our common stock was approximately 22 on March 9, 2015.

Dividends.

We have not paid any cash dividends since inception. In addition, our reserve-based revolving credit facility and the indenture governing our Senior Notes limit and restrict our ability to pay dividends on our capital stock. We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Stock Performance Graph.

The following performance graph and related information shall not be deemed "soliciting material" or is not to be filed with the SEC, such information shall not be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph below shows the cumulative total return to our commons stock holders from the date our common stock began trading on the NYSE through December 31, 2014, as compared to the cumulative five-year total returns on the Standard and Poor's 500 Index ("S&P 500")

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and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P O&G E&P") for the same period of time. The comparison was prepared on the following assumptions:

- $100 was invested in our common stock at its initial public offering price of $13 per share and invested in the S&P 500 and the S&P O&G E&P on April 20, 2012 at the closing price on such date; and

- Dividends, if any, are reinvested.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected financial data of the Company and its consolidated subsidiary over the five-year period ended December 31, 2014, which information has been derived from the Company's audited financial statements. This information should be read in conjunction with, and is qualified in its entirety by, the more detailed information in the Company's financial statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

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Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2014, 2013 and 2012 and the balance sheet data as of December 31, 2014 and 2013 are derived from our audited consolidated financial statements and the notes thereto included elsewhere in this Annual Report on Form 10-K. The historical financial data for the years ended December 31, 2010 and 2011 and the balance sheet data as of December 31, 2012, 2011 and 2010 are derived from our audited financial statements not included in this Annual Report on Form 10-K.

	As of and for the Year Ended December 31,				
	2014(1)	2013(2)	2012(3)	2011	2010
	(in thousands, except per share amounts)				
Income Statement Data					
Total revenues	$ 794,183	$ 469,506	$ 247,673	$ 209,433	$ 63,052
Net income (loss)	116,929	(343,985)	(150,097)	16,657	(15,635)
Net income (loss) attributable to common shareholders(4)	67,271	(359,574)	(156,597)	16,657	(15,635)
Net income (loss) per share attributable to common shareholders(5)					
Basic and diluted	$ 1.01	$ (5.47)	$ (2.61)	N/A	N/A
Balance Sheet Data					
Cash and cash equivalents	$ 11,557	$ 33,163	$ 18,878	$ 7,344	$ 11,917
Net property and equipment	2,123,116	2,094,894	1,567,408	574,079	397,126
Total assets	2,475,793	2,342,107	1,684,010	624,656	427,004
Long-term debt	1,735,150	1,701,150	694,000	234,800	89,600
Stockholders'/members' equity	465,862	339,999	677,469	285,502	255,879
Weighted average number of common shares outstanding	66,440	65,766	59,979	N/A	N/A
Other Financial Data					
Net cash provided by operating activities	$ 356,838	$ 227,102	$ 137,249	$ 141,550	$ 50,768
Net cash used in investing activities	(409,559)	(1,193,846)	(773,608)	(242,619)	(139,618)
Net cash provided by financing activities	31,114	981,029	647,893	96,496	96,414
Adjusted EBITDA(6)	474,098	330,759	144,619	152,616	53,274

(1) The year ended December 31, 2014 reflects the Pine Prairie sale, which closed on May 1, 2014. For a discussion of significant divestitures, see Note 7 Acquisitions and Divestitures of Oil and Gas Properties in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

(2) The year ended December 31, 2013 reflects the Anadarko Basin Acquisition, which closed on May 31, 2013. For a discussion of significant, see Note 7 Acquisitions and Divestitures of Oil and Gas Properties in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

(3) The year ended December 31, 2012 reflects the Eagle Property Acquisition, which closed on October 1, 2012. For a discussion of significant acquisitions, see Note 7 Acquisitions and Divestitures of Oil and Gas Properties in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

(4) The years ended December 31, 2014, 2013 and 2012 includes the effect of an undeclared Series A Preferred Stock dividend of $10.4 million, $15.6 million and $6.5 million, which is, at the Company's option, to be paid in cash or in shares upon conversion. See Note 10 Preferred Stock in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

(5) The net loss per share attributable to common shareholders for the year ended December 31, 2012 is on a pro forma basis, as our common stock did not trade for the entirety of 2012 (trading began on the NYSE on April 20, 2012).

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

Non-GAAP Financial Measures and Reconciliations

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDA as earnings before interest income and expense, income taxes, depreciation, depletion and amortization, property impairments, asset retirement obligation accretion, unrealized derivative gains and losses and non-cash share-based compensation expense. Adjusted

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EBITDA is not a measure of net income or cash flows as determined by United States generally accepted accounting principles, or GAAP. We believe that Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude items such as property and inventory impairments, asset retirement obligation accretion, unrealized derivative gains and losses and non-cash share-based compensation expense, net of amounts capitalized, from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following table presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP measure of net income (loss) and net cash provided by operating activities, respectively.

	As of and for the Year Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
			(in thousands)		
Adjusted EBITDA reconciliation to net income (loss):					
Net income (loss)	$ 116,929	$ (343,985)	$ (150,097)	$ 16,657	$ (15,635)
Depreciation, depletion and amortization	269,935	250,396	125,561	91,699	41,827
Impairment in carrying value of oil and gas properties	86,471	453,310			
Loss on sale/impairment of field equipment inventory	4,056	615			
(Gains) Losses on commodity derivative contracts net	(139,189)	44,284	11,158	4,844	26,268
Net cash paid for commodity derivative contracts not designated as hedging instruments	(18,332)	(17,585)	(15,825)	(16,733)	(870)
Income tax expense (benefit)	6,395	(146,529)	157,886		
Interest income	(39)	(33)	(245)	(23)	(9)
Interest expense, net of amounts capitalized	137,548	83,138	12,999	2,094	
Asset retirement obligation accretion	1,706	1,435	723	334	175
Share-based compensation, net of amounts capitalized	8,618	5,713	2,459	53,744	1,518
Adjusted EBITDA	**$ 474,098**	**$ 330,759**	**$ 144,619**	**$ 152,616**	**$ 53,274**

	As of and for the Year Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
			(in thousands)		
Adjusted EBITDA reconciliation to net cash provided by operating activities:					
Net cash provided by operating activities	$ 356,838	$ 227,102	$ 137,249	$ 141,550	$ 50,768
Changes in working capital(1)	(12,392)	26,507	(3,854)	9,845	2,829
Interest income	(39)	(33)	(245)	(23)	(9)
Interest expense, net of amounts capitalized and accrued but not paid	137,548	83,138	12,999	2,094	
Amortization of deferred financing costs	(7,857)	(5,955)	(1,530)	(850)	(314)
Adjusted EBITDA	**$ 474,098**	**$ 330,759**	**$ 144,619**	**$ 152,616**	**$ 53,274**
Acquisition and transaction costs	4,129	11,803	14,884		
Adjusted EBITDA, before acquisition and transaction costs	**$ 478,227**	**$ 342,562**	**$ 159,503**	**$ 152,616**	**$ 53,274**

(1) Changes in working capital for all periods have been adjusted for the loss on sale/impairment of field equipment inventory and current taxes.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains "forward-looking statements" that are based on management's current expectations, estimates and projections about our business and operations, and involves risks and uncertainties. Our actual results may differ materially from those currently anticipated and expressed in such forward-looking statements as a result of a number of factors, including those we discuss under "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements" and elsewhere in this Annual Report on Form 10-K.

Overview

We are an independent exploration and production company focused on the application of modern drilling and completion techniques to oil-prone resources in the United States. Our operations are primarily focused on exploration and production activities in the Mississippian Lime, Anadarko Basin and Gulf Coast.

Prior to October 1, 2012, all of our growth had been driven through the development of our leasehold acreage located in Louisiana. We initiated operations in 1993 in our North Cowards Gully project area and slowly aggregated leasehold acreage in that project area and others over the next eighteen years. In August 2008, First Reserve acquired a majority interest in us and, along with members of our senior management, provided a significant amount of growth capital to expand our exploration and development program in Louisiana.

On October 1, 2012, we closed on the acquisition of all of Eagle Energy Production, LLC's producing properties as well as its developed and undeveloped acreage primarily in the Mississippian Lime liquids play in Oklahoma for $325 million in cash and 325,000 shares of the Series A Preferred Stock with an initial liquidation preference value of $1,000 per share (the "Eagle Property Acquisition"). We 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, we 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. We 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, we had oil and gas operations and properties in Louisiana, Oklahoma and Texas. At December 31, 2014, we operated oil and natural gas properties and evaluated performance based on one reportable segment as there were not significantly different economic or operational environments within its oil and natural gas properties.

Our current activities are focused on evaluating and developing our asset base, optimizing our acreage position, and identifying potential expansion areas across our Mississippian and Anadarko Basin operating areas. As of December 31, 2014, since the third quarter of 2008 we had spud approximately 386 gross wells (including 173 in our Mississippian operating area since the fourth quarter of 2012 and 69 in our Anadarko operating area since the second quarter of 2013).

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As of December 31, 2014, our properties consisted of approximately 252,200 net acre leasehold, with 667 gross active producing wells, 92% of which we operate, and in which we held an average working interest of approximately 77%. As of December 31, 2014, our estimated net proved reserves were 153.7 MMBoe, of which 59% was oil or NGLs and 48% was proved developed. During the three months and year ended December 31, 2014, our properties had aggregate average net daily production of approximately 33,764 Boe/d and 32,137 Boe/d, respectively.

Pine Prairie Disposition

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 Parish, Louisiana to a private buyer for a purchase price of $170 million, subject to standard post-closing adjustments (the "Pine Prairie Disposition"). Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and did 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. On May 1, 2014, we closed on the sale for net cash proceeds of $147.7 million, of which $131.0 million was used to reduce amounts outstanding under our revolving credit facility, with the remainder retained for transaction expenses and working capital purposes. Subsequent to May 1, 2014, our remaining Gulf Coast producing assets are located in Beauregard and Calcasieu Parishes.

Exploration Agreement with PetroQuest

On June 25, 2014, we entered into an exploration agreement with PetroQuest Energy LLC ("PetroQuest") with an effective date of May 1, 2014, in which we conveyed to PetroQuest an undivided 50% of our right, title and interest in and to our acreage and other interests in the Fleetwood prospect area in Louisiana.

With the execution of the agreement, PetroQuest paid us $3.0 million in cash consideration on July 3, 2014 and, in January 2015, PetroQuest subsequently paid us additional cash consideration of $7.0 million. As further consideration, PetroQuest granted us (or will pay on our behalf) an additional non-interest bearing total sum of $14.0 million, to be credited or paid against our share of cost or expenses incurred to develop the prospect area, including but not limited to, all mineral lease acquisition or maintenance costs and all drilling, completion, equipping and facility costs. For any amounts not fully paid or credited on or before December 31, 2015, we can elect to take the remaining portion in cash.

Sale of Dequincy Assets

In March 2015, we executed a PSA for the sale of our Dequincy assets, our only remaining producing properties in Louisiana, for total consideration of $44 million (subject to customary purchase price adjustments). The PSA includes our ownership interest in developed and undeveloped acreage totaling approximately 12,700 net mineral acres in the Dequincy area. During the fourth quarter 2014, the properties produced approximately 1,300 Boe per day. The transaction does not include our acreage and interests in the Fleetwood area of Louisiana. The net proceeds from the sale will be used to pay down a portion of the outstanding borrowings under our revolving credit facility and for general corporate purposes. The transaction has an effective date of March 1, 2015 and is expected to close on or before April 30, 2015, subject to customary closing conditions.

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Risks, Uncertainties, and Going Concern

Our liquidity outlook has changed since the third quarter of 2014 due to the substantial decrease in commodity prices. This has resulted in lower operating cash flows than expected and, if commodity prices remain low compared to recent historical prices, will result in future significantly lower levels of operating cash flows as our current hedging contracts expire during 2015.

As of December 31, 2014, we had available cash of approximately $11 million and availability under our senior reserve-based revolving credit facility (the "Credit Facility") of approximately $90 million. If we have a downward revision in estimates of our proved reserves, our borrowing base for our revolving credit facility may be reduced, and as a result, our available liquidity will be reduced. As of December 31, 2014, payments due on our contractual obligations during the next twelve months are greater than $150 million. This includes approximately $130 million of interest payments on our senior notes and other operating expenses such as fixed drilling commitments and operating leases. We expect we will need to complete certain transactions, including management of our debt capital structure and potential asset sales, to have sufficient liquidity to satisfy these obligations in the long-term.

As a result of the events described above, we believe that our forecasted cash and available credit capacity are not expected to be sufficient to meet our commitments as they come due over the next twelve months and that we will not be able to remain in compliance with our current debt covenants unless we are able to successfully increase our liquidity. The uncertainty associated with our ability to meet our commitments as they come due or to repay our outstanding debt raises substantial doubt about our ability to continue as a going concern. The accompanying consolidated financial statements do not include any adjustments related to the recoverability and classification of recorded assets or the amounts and classification of liabilities that might result from the uncertainty associated with our ability to meet our obligations as they come due.

Sources of Our Revenue

Oil, natural gas and natural gas liquids. Our revenues are derived from the sale of oil and natural gas production, as well as the sale of NGLs that are extracted from our high Btu content natural gas. Our oil and gas revenues do not include the effects of derivatives, and may vary significantly from period to period as a result of changes in production volumes or commodity prices. A further or extended decline in commodity prices could materially and adversely affect our business, financial condition and results of operations. Prices for oil, natural gas and NGLs fluctuate widely and affect:

- the amount of cash flows available for capital expenditures;
- our ability to borrow and raise additional capital;
- the quantity of oil, natural gas and NGLs we can economically produce; and
- revenues and profitability.

Average market prices for NGLs and oil decreased significantly in the last part of 2014 with continued weakness into the first quarter of 2015. If commodity prices remain at levels experienced during the fourth quarter of 2014 and the first quarter of 2015 throughout 2015, we expect significantly lower revenues and operating cash flows compared to historical results.

Realized and unrealized gain (loss) on commodity derivative financial contracts. We utilize commodity derivatives to reduce our exposure to fluctuations in the prices of oil, NGLs and natural gas. In addition, we utilize derivatives to help mitigate our exposure to fluctuations in Louisiana Light Sweet ("LLS") oil prices, which is the index price we receive for our Gulf Coast oil production, as compared to West Texas Intermediate ("NYMEX WTI") benchmark oil prices, which is the index price we receive in the Mississippian Lime and Anadarko Basin areas. Accordingly, our income statements reflect (i) the recognition of unrealized gains and losses associated with our open derivative contracts as commodity prices change and commodity derivatives contracts expire or new ones are entered into, and (ii) our realized gains or losses on the settlement of these commodity derivative contracts. Unrealized gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract prices on the derivatives. If the expected future commodity prices increase compared to the contract prices on the derivatives, unrealized losses are recognized. Conversely, if the expected future commodity prices decrease compared to the contract prices on the derivatives, unrealized gains are recognized. Since we have elected not to apply hedge accounting to our derivatives, we reflect the unrealized and realized gains and losses in our current income statement periods based on the mark-to-market value at the end of each month. Cash flows associated with derivative financial instruments are reflected in cash flow from operations in our consolidated statement of cash flows.

Commodity prices. Our revenues are heavily influenced by commodity prices, which are subject to wide fluctuations in response to changes in supply and demand. For a description of factors that may impact future commodity prices, please read "Risk Factors Risks Related to the Oil and Natural Gas Industry and Our Business." For the prices we received per unit of volume for our oil, NGLs and natural gas, both including and excluding the effects of our commodity derivative contracts, see table included on page 66.

Our Expenses

Lease operating and workover expenses. These are daily costs incurred to bring oil and gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include natural gas treating expenses and the handling and disposal of produced water as well as maintenance and repair expenses related to our oil and gas properties. Lease operating expenses include both a portion of costs that are fixed in nature, such as infrastructure costs, as well as variable costs resulting from additional wells and production. As production increases, our average lease operating expense per barrel of oil equivalent is typically reduced because fixed costs do not increase proportionately with production. Workover expense includes major remedial operations on a completed well to restore, maintain, or improve a well's production and is closely correlated to the levels of workover activity. Because workover projects are pursued on an as needed basis and are not regularly scheduled, workover expense is not necessarily comparable from period to period.

Gathering and transportation. These costs are incurred for the gathering and transportation of natural gas to the contractual delivery point. For 2014, these costs primarily relate to the amended gas transportation, gathering and processing contract which commenced during the third quarter of 2013 in the Mississippian Lime that includes a $0.36 per MMBtu gathering fee based upon wellhead volumes.

Severance and other taxes. Severance taxes are paid on produced oil and gas based on a percentage of revenues from products sold at market prices or at fixed rates established by federal, state, or local taxing authorities. We attempt to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the severance taxes we pay correlate to the changes in oil and gas revenues. Ad valorem taxes are property taxes assessed based on the value of property and are also included in this expense category.

Depreciation, depletion and amortization. Under the full cost accounting method, we capitalize costs within a cost center and systematically expense those costs on a unit of production basis based on proved oil and natural gas reserve quantities. We calculate depletion on the following types of costs: (i) all capitalized costs, other than the cost of investments in unproved properties for which proved reserves have not yet been assigned, less accumulated amortization; (ii) estimated future expenditures to be incurred in developing proved reserves; and (iii) estimated dismantlement and abandonment costs, net of any associated salvage value.

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Impairment in carrying value of oil and gas properties/Ceiling test. As a public company, we apply Rule 4-10 of Regulation S-X, which requires the full-cost ceiling test to be performed on a quarterly basis. The test establishes a limit (ceiling) on the book value of oil and gas properties. The capitalized costs of proved oil and gas properties, net of accumulated depreciation, depletion and amortization ("DD&A") and the related deferred income taxes, may not exceed this "ceiling." The ceiling limitation is equal to the sum of: (i) the present value of estimated future net revenues from the projected production of proved oil and gas reserves, excluding future cash outflows associated with settling asset retirement obligations accrued on the balance sheet, calculated using the average oil and natural gas sales price we received as of the first trading day of each month over the preceding twelve months (such average price is held constant throughout the life of the properties) and a discount factor of 10%; (ii) the cost of unproved and unevaluated properties excluded from the costs being amortized; (iii) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (iv) related income tax effects. If capitalized costs exceed this ceiling, the excess is charged to impairment expense in the accompanying consolidated statements of operations.

General and administrative expense. General and administrative expense consists, among other items, of overhead, including payroll and benefits for our corporate staff, non-cash charges for share-based compensation, costs of maintaining our headquarters, franchise taxes, audit and other professional fees, legal compliance, Exchange Act reporting expenses, expenses associated with Sarbanes-Oxley compliance, investor relations, director and officer liability insurance costs, and director compensation.

Certain of our employees hold units in Midstates Incentive Holdings LLC that entitle the holders to a portion of the proceeds to be received by First Reserve, our private equity sponsor, upon sales of our common stock by FRMI. Any payments with respect to these units will only occur if and when First Reserve achieves certain minimum return hurdles (defined as certain multiples of First Reserve's capital contributions plus investment expenses) on its investment through the sale of its shares of our common stock. While these proceeds will not involve any cash payment by us, we will recognize a non-cash compensation expense, which may be material, in the period any such payment is made. See Note 11 to our audited financial statements for the year ended December 31, 2014.

Acquisition and transaction costs. The Eagle Property Acquisition and the Anadarko Basin Acquisition qualify as the acquisition of a business under Accounting Standards Codification Topic 805, Business Combinations ("ASC 805"). Acquisition and transaction costs are costs we have has incurred as a result of these acquisitions or as a result of asset disposal transactions such as the Pine Prairie Disposition, and include finders' fees; advisory, legal, accounting, valuation and other professional and consulting fees; and acquisition or disposition related general and administrative costs. ASC 805 requires acquisition related costs to be expensed as incurred and as services are received.

Other expense. Other expense consists of, among other things, losses on disposal of, or market value adjustments to, field equipment inventory, penalties on early termination of drilling contracts and other miscellaneous expense items.

Interest expense. We issued $600 million and $700 million in Senior Notes on October 1, 2012 and May 31, 2013, respectively. Additionally, we finance a portion of our working capital requirements and capital expenditures with borrowings under our revolving credit facility. As a result, we incur interest expense, a portion of which is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our note holders and the lenders under our revolving credit facility in interest expense, as well as the amortization of the related deferred financing costs, net of amounts capitalized to unproved properties.

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Results of Operations

The following tables summarize our revenues, production and price data for the periods indicated. Prior to May 1, 2014, our operating results include production, revenue and lease operating expenses attributable to our Pine Prairie field, the sale of which closed effective May 1, 2014. Where applicable, in the following discussion, we have noted normalized production, revenue, lease operating expenses and percentages for prior periods as though the Pine Prairie Disposition occurred as of the beginning of that period.

Revenues

	Years Ended December 31,					
	2014		2013		2012	
			(in thousands)			
REVENUES:						
Oil sales	$ 466,655	71%	$ 387,226	76%	$ 218,430	85%
Natural gas liquid sales	87,771	13%	62,340	12%	23,617	9%
Natural gas sales	99,204	16%	63,187	12%	16,030	6%
Total oil, natural gas, and natural gas liquids sales	**653,630**	**100%**	**512,753**	**100%**	**258,077**	**100%**
Realized losses on commodity derivative contracts, net	(18,332)	(13)%	(17,585)	40%	(15,825)	142%
Unrealized gains (losses) on commodity derivative contracts, net	157,521	113%	(26,699)	60%	4,667	(42)%
Gains (losses) on commodity derivative contracts net	**139,189**	**100%**	**(44,284)**	**100%**	**(11,158)**	**100%**
Other	1,364		1,037		754	
Total revenues	**$ 794,183**		**$ 469,506**		**$ 247,673**	

Production

	Years Ended December 31,				
	2014	% Change	2013	% Change	2012
PRODUCTION DATA:					
Oil (MBbls)	5,144	32%	3,904	87%	2,093
Natural gas liquids (MBbls)	2,417	41%	1,719	179%	617
Natural gas (MMcf)	25,013	34%	18,657	228%	5,695
Oil equivalents (MBoe)	11,730	34%	8,733	139%	3,659
Oil (Boe/day)	14,094	32%	10,697	87%	5,719
Natural gas liquids (Boe/day)	6,622	41%	4,711	179%	1,686
Natural gas (Mcf/day)	68,528	34%	51,116	228%	15,559
Average daily production (Boe/d)	32,137	34%	23,927	139%	9,999

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Prices

	Years Ended December 31,				
	2014	% Change	2013	% Change	2012
AVERAGE SALES PRICES:					
Oil, without realized derivatives (per Bbl)	$ 90.71	(9)%	$ 99.18	(5)%	$ 104.35
Oil, with realized derivatives (per Bbl)	$ 87.40	(6)%	$ 93.41	(2)%	95.05
Natural gas liquids, without realized derivatives (per Bbl)	$ 36.31	0%	$ 36.26	(5)%	38.27
Natural gas liquids, with realized derivatives (per Bbl)	$ 36.40	(2)%	$ 37.09	(8)%	40.48
Natural gas, without realized derivatives (per Mcf)	$ 3.97	17%	$ 3.39	21%	2.81
Natural gas, with realized derivatives (per Mcf)	$ 3.91	9%	$ 3.58	12%	3.21

Oil, Natural Gas and Natural Gas Liquids Revenues.

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

Our oil sales revenues increased by $79.5 million, or 21%, to $466.7 million during the year ended December 31, 2014 as compared to $387.2 million for the year ended December 31, 2013. Oil volumes sold increased 1,240 MBbls or 32% to 5,144 MBbls for the year ended December 31, 2014 from 3,904 MBbls for the year ended December 31, 2013. The increase in oil volumes sold was due to an increase of 1,403 MBbls in production volumes from our Mississippian Lime area attributable to continued increased drilling activity in 2014, and 648 MBbls of additional production volumes from our Anadarko Basin area (the 2013 comparative period included only seven months of results due to the timing of the Anadarko Basin Acquisition), partially offset by a decrease in Gulf Coast production of 811 MBbls (of which, approximately 632 MBbls was related to the Pine Prairie area). For the twelve months ended December 31, 2014, we brought approximately 120 wells online, which contributed to the 34% increase in daily production. Average oil sales prices, without realized derivatives, decreased by $8.47 per barrel, or 9%, to $90.71 per barrel for the year ended December 31, 2014 as compared to $99.18 for the year ended December 31, 2013. Of the $466.7 million in total oil sales revenues, $272.9 million was from Mississippian Lime operations, $134.0 million was from the Anadarko Basin and $59.8 million was from the Gulf Coast.

Our NGLs sales revenues increased by $25.5 million, or 41%, to $87.8 million during the year ended December 31, 2014 as compared to $62.3 million for the year ended December 31, 2013. NGLs volumes sold increased 698 MBbls, or 41%, to 2,417 MBbls for the year ended December 31, 2014 as compared to 1,719 MBbls for the year ended December 31, 2013. The increase in NGLs volumes sold was attributable to an increase of 663 MBbls of production volumes from our Mississippian Lime area and 250 MBbls of additional production volumes from our Anadarko Basin area (the 2013 comparative period included only seven months of results due to the timing of the Anadarko Basin Acquisition), partially offset by a decrease in Gulf Coast production of 215 MBbls (of which, approximately 137 MBbls related to the Pine Prairie area). Average NGLs prices, without realized derivatives, increased by $0.05 per barrel, to $36.31 per barrel for the year ended December 31, 2014 as compared to $36.26 per barrel for the year ended December 31, 2013. Of the $87.8 million in total NGLs revenues, $57.7 million was from Mississippian Lime operations, $23.8 million was from the Anadarko Basin and $6.3 million was from the Gulf Coast.

Our natural gas sales revenues increased by $36.0 million, or 57%, to $99.2 million during the year ended December 31, 2014 as compared to $63.2 million for the year ended December 31, 2013. Natural gas volumes sold increased 6,356 MMcf, or 34%, to 25,013 MMcf for the year ended December 31, 2014 as compared to 18,657 MMcf for the year ended December 31, 2013. The increase in natural gas volumes sold was attributable to an increase of 6,293 MMcf of production volumes from our

Mississippian Lime area and 1,960 MMcf of additional production volumes from our Anadarko Basin area (the 2013 comparative period included only seven months of results due to the timing of the Anadarko Basin Acquisition), partially offset by a 1,897 MMcf decrease in production from our Gulf Coast area (of which, approximately 1,577 MMcf related to the Pine Prairie area). Average natural gas prices, without realized derivatives, increased by $0.58 per Mcf, or 17%, to $3.97 per Mcf for the year ended December 31, 2014 as compared to $3.39 per Mcf for the year ended December 31, 2013. Of the $99.2 million in total natural gas sales revenues, $75.4 million was from Mississippian Lime operations, $21.1 million was from Anadarko Basin and $2.7 million was from the Gulf Coast.

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

Our oil sales revenues increased by $168.8 million, or 77%, to $387.2 million during the year ended December 31, 2013 as compared to $218.4 million for the year ended December 31, 2012. Oil volumes sold increased 1,811 MBbls or 87% to 3,904 MBbls for the year ended December 31, 2013 from 2,093 MBbls for the year ended December 31, 2012. The increase in oil volumes sold was attributable to an increase of 1,463 MBbls in production volumes from our Mississippian area attributable to a full year of production from the assets (which were acquired on October 1, 2012) and the results from increased drilling activity in 2013, and the addition of 817 MBbls in production volumes from our Anadarko Basin area (which was acquired on May 31, 2013), partially offset by a decrease in Gulf Coast production of 469 MBbls. Production from the Gulf Coast declined due to lower drilling activity during the latter half of 2013 as we focused drilling capital on our newly acquired Anadarko Basin assets. Average oil sales prices, without realized derivatives, decreased by $5.17 per barrel, or 5%, to $99.18 per barrel for the year ended December 31, 2013 as compared to $104.35 for the year ended December 31, 2012, partly due to lower oil prices during 2013 as well as lower oil prices received for our Mississippian Lime and Anadarko Basin production, which is priced off WTI as opposed to LLS for our Gulf Coast production. Of the $387.2 million in total oil sales revenues, $151.7 million was from Gulf Coast operations, $155.9 million was from Mississippian and $79.6 million was from Anadarko Basin.

Our NGLs sales revenues increased by $38.7 million, or 164%, to $62.3 million during the year ended December 31, 2013 as compared to $23.6 million for the year ended December 31, 2012. NGLs volumes sold increased 1,102 MBbls, or 179%, to 1,719 MBbls for the year ended December 31, 2013 as compared to 617 MBbls for the year ended December 31, 2012. The increase in NGLs volumes sold was attributable to an increase of 789 MBbls of production volumes from our Mississippian Lime area and the addition of 395 MBbls of production volumes from our Anadarko Basin area, partially offset by a decrease in Gulf Coast production of 82 MBbls. Average NGLs prices, without realized derivatives, decreased by $2.01 per barrel, or 5%, to $36.26 per barrel for the year ended December 31, 2013 as compared to $38.27 per barrel for the year ended December 31, 2012. Of the $62.3 million in total NGLs revenues, $13.9 million was from Gulf Coast operations, $34.5 million was from Mississippian Lime and $13.9 million was from Anadarko Basin.

Our natural gas sales revenues increased by $47.2 million, or 295%, to $63.2 million during the year ended December 31, 2013 as compared to $16.0 million for the year ended December 31, 2012. Natural gas volumes sold increased 12,962 MMcf, or 228%, to 18,657 MMcf for the year ended December 31, 2013 as compared to 5,695 MMcf for the year ended December 31, 2012. The increase in natural gas volumes sold was attributable to an increase of 10,946 MMcf of production volumes from our Mississippian Lime area and the addition of 3,489 MMcf of production volumes from our Anadarko Basin area, partially offset by a 1,473 MMcf decrease in production from our Gulf Coast area. Average natural gas prices, without realized derivatives, increased by $0.58 per Mcf, or 21%, to $3.39 per Mcf for the year ended December 31, 2013 as compared to $2.81 per Mcf for the year ended December 31, 2012. Of the $63.2 million in total natural gas sales revenues, $9.4 million was from Gulf Coast operations, $42.6 million was from Mississippian and $11.2 million was from Anadarko Basin.

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Gains/Losses on Commodity Derivative Contracts Net.

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

Our mark-to-market ("MTM") derivative positions moved from an unrealized loss of $26.7 million as of December 31, 2013 to an unrealized gain of $157.5 million for the year ending December 31, 2014. The NYMEX WTI closing price on December 31, 2014 was $53.27 per barrel compared to a closing price of $98.42 per barrel on December 31, 2013 and the average oil price of our open derivative contracts was $88.72 per barrel.

The realized loss on derivatives for the year ended December 31, 2014 was $18.3 million compared to a realized loss of $17.6 million for the year ended December 31, 2013. See the following table:

	Year Ended December 31, 2014	
	Realized Gain (Loss)	**Average Sales Price**
	(in thousands)	
Oil commodity contracts	$ (17,060)	$ 87.40
Natural gas liquids commodity contracts	217	36.40
Natural gas commodity contracts	(1,489)	3.91
Realized losses on commodity derivative contracts, net	**$ (18,332)**	

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

Our MTM derivative positions moved from an unrealized gain of $4.7 million as of December 31, 2012 to an unrealized loss of $26.7 million for the year ending December 31, 2013. We entered into additional derivative contracts during 2013 and the MTM change resulted from higher average hedge volumes and unfavorable derivative contract price variances versus the forward strip price for our production on December 31, 2013. The NYMEX WTI closing price on December 31, 2013 was $98.42 per barrel compared to a closing price of $91.82 per barrel on December 31, 2012.

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The realized loss on derivatives for the year ended December 31, 2013 was $17.6 million compared to a realized loss of $15.8 million for the year ended December 31, 2012. See the following table (in thousands):

	Year Ended December 31, 2013 Realized Gain (Loss)	Average Sales Price
	(in thousands)	
Oil commodity contracts	$ (22,529)	$ 93.41
Natural gas liquids commodity contracts	1,428	37.09
Natural gas commodity contracts	3,516	3.58
Realized losses on commodity derivative contracts, net	**$ (17,585)**	

Expenses

	Years Ended December 31, 2014	2013	2012	Years Ended December 31, 2014	2013	2012
	(in thousands)			(per Boe)		
EXPENSES:						
Lease operating and workover	$ 79,598	$ 73,414	$ 30,500	$ 6.79	$ 8.41	$ 8.34
Gathering and transportation	13,404	5,455		$ 1.14	$ 0.62	$
Severance and other taxes	24,266	27,237	24,921	$ 2.07	$ 3.12	$ 6.81
Asset retirement accretion	1,706	1,435	723	$ 0.15	$ 0.17	$ 0.20
Depreciation, depletion, and amortization	269,935	250,396	125,561	$ 23.01	$ 28.67	$ 34.32
Impairment of oil and gas properties	86,471	453,310		$ 7.37	$ 51.91	$
General and administrative	48,733	53,250	30,541	$ 4.15	$ 6.10	$ 8.35
Acquisition and transaction costs	4,129	11,803	14,884	$ 0.35	$ 1.35	$ 4.07
Other	5,108	615		$ 0.44	$ 0.07	$
Total expenses	**$ 533,350**	**$ 876,915**	**$ 227,130**	**$ 45.47**	**$ 100.42**	**$ 62.09**

Lease Operating and Workover.

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

Lease operating and workover expenses increased $6.2 million, or 8%, to $79.6 million for the year ended December 31, 2014 compared to $73.4 million for the year ended December 31, 2013. Lease operating expenses increased $9.2 million, or 14%, to $74.5 million for the year ended December 31, 2014 as compared to $65.3 million for the year ended December 31, 2013. This change is almost entirely attributable to the increase in producing well count for the Mississippian Lime and Anadarko Basin areas year over year; there were approximately 150 more active wells in 2014 for these areas versus the prior year. Workover expenses decreased $3.0 million, or 37%, to $5.1 million for the year ended December 31, 2014, as compared to $8.1 million for the year ended December 31, 2013. The Gulf Coast region workover costs decreased approximately $2.2 million period over period. While the total lease operating and workover expenses increased, the per unit amounts decreased to $6.79 per Boe for the year ended December 31, 2014 from $8.41 per Boe for the year ended December 31, 2013, a decrease of 19%, driven primarily by the 34% increase in production year over year.

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

Lease operating and workover expenses increased $42.9 million, or 141%, to $73.4 million for the year ended December 31, 2013 compared to $30.5 million for the year ended December 31, 2012. Lease operating expenses increased $38.8 million, or 146%, to $65.3 million for the year ended December 31, 2013 as compared to $26.5 million for the year ended December 31, 2012. Lease operating expenses for the year ended December 31, 2013, included a full year of costs related to the assets acquired in the Eagle Property Acquisition (compared to only three months for the year ended December 31, 2012) and seven months of costs related to the assets acquired in the Anadarko Basin Acquisition which closed on May 31, 2013. Of this increase, $31.3 million relates to the increase in producing well count in all areas, which increased approximately 150% year over year due to the Anadarko Basin Acquisition and increased drilling activity in the Mississippian Lime area. The remaining $7.5 million is attributable to surface maintenance and other costs. During 2013, we continued to make investments in our operating areas to reduce lease operating costs, specifically in salt water disposal infrastructure in our Gulf Coast region and in our electrical infrastructure and salt water disposal infrastructure in the Mississippian Lime. Workover expenses increased $4.1 million, or 103%, to $8.1 million for the year ended December 31, 2013, as compared to $4.0 million for the year ended December 31, 2012. Of this increase, approximately $2.9 million relates to the Mississippian Lime area workover costs and $1.3 million relates to the Anadarko area workover costs partially offset by a decrease of $0.1 million in Gulf Coast workover costs. Lease operating and workover expenses increased to $8.41 per Boe for the year ended December 31, 2013 from $8.34 per Boe for the year ended December 31, 2012, an increase of 1%, which was primarily attributable to the factors noted above.

Gathering and Transportation.

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

Gathering and transportation expenses increased $7.9 million, or 144%, to $13.4 million for the year ended December 31, 2014 compared to $5.5 million for the year ended December 31, 2013. These expenses are primarily attributable to an amended gas transportation, gathering and processing contract which commenced during the third quarter of 2013 in the Mississippian Lime and included a $0.36 per MMBtu gathering fee based upon wellhead volumes. As such, the year ended December 31, 2013 includes only two quarters of the expense. No gathering and transportation expenses were incurred in 2012.

Severance and Other Taxes.

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Total oil, natural gas, and natural gas liquids sales	**$ 653,630**	**$ 512,753**	**$ 258,077**
Severance taxes	17,723	21,338	22,121
Ad valorem and other taxes	6,543	5,899	2,800
Severance and other taxes	**$ 24,266**	**$ 27,237**	**$ 24,921**
Severance taxes as a percentage of sales	**2.7%**	**4.2%**	**8.6%**
Severance and other taxes as a percentage of sales	**3.7%**	**5.3%**	**9.7%**

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

Severance and other taxes decreased $2.9 million, or 11%, to $24.3 million for the year ended December 31, 2014 as compared to $27.2 million for the year ended December 31, 2013. Severance taxes decreased $3.6 million, or 17%, to $17.7 million for the year ended December 31, 2014 compared to $21.3 million for the year ended December 31, 2013 and as a percentage of sales, changed from 4.2% for the year ended December 31, 2013 to 2.7% for the corresponding 2014 period due to lower effective severance tax rates in our Mississippian Lime and Anadarko Basin areas and lower production period-over-period in the relatively higher tax Gulf Coast region resulting from reduced drilling activity in 2014 and the Pine Prairie Disposition. Ad valorem taxes increased $0.7 million, or 12%, to $6.6 million for the year ended December 31, 2014, as compared to $5.9 million for the year ended December 31, 2013, related to increased ad valorem taxes in the Anadarko Basin and Gulf Coast area.

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

Severance and other taxes increased $2.3 million, or 9%, to $27.2 million for the year ended December 31, 2013 as compared to $24.9 million for the year ended December 31, 2012. Severance taxes decreased by $0.8 million, or 4%, and accounted for $21.3 million of the 2013 amount. This decrease was primarily attributable to the geographic production mix, with lower oil, NGL and natural gas sales revenue from the Gulf Coast area, and to higher oil, NGLs and natural gas sales revenue from the Mississippian and Anadarko Basin, where severance tax rates are lower than in the Gulf Coast. Severance taxes for the year ended December 31, 2013 and 2012 were 4.2% and 8.6%, respectively, as a percentage of oil, NGL and natural gas sales revenue.

Ad valorem taxes increased $3.1 million, or 111%, to $5.9 million for the year ended December 31, 2013 as compared to $2.8 million for the year ended December 31, 2012. This change directly correlates to the increase in active well count, which increased approximately 150% year over year due to the Anadarko Basin Acquisition and development drilling in 2013 across all areas.

Depreciation, Depletion and Amortization (DD&A).

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

DD&A expense increased $19.5 million, or 8%, to $269.9 million for the year ended December 31, 2014 compared to $250.4 million for the year ended December 31, 2013. The DD&A rate for the year ended December 31, 2014 was $23.01 per Boe compared to $28.67 per Boe for the year ended December 31, 2013. The increase in total DD&A expense for the year ended December 31, 2014 was primarily due to higher oil, NGLs and natural gas production attributable to a full year of production from the Anadarko Basin Acquisition assets as well as developmental drilling during 2014 in the Mississippian Lime area. The lower DD&A rate per Boe is attributable to the overall growth in proved reserves during 2014.

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

DD&A expense increased $124.8 million, or 99%, to $250.4 million for the year ended December 31, 2013 compared to $125.6 million for the year ended December 31, 2012. The DD&A rate for the year ended December 31, 2013 was $28.67 per Boe compared to $34.32 per Boe for the year ended December 31, 2012. The increase in total DD&A expense for the year ended December 31, 2013 was primarily due to higher oil, NGLs and natural gas production attributable to a full year of production from the Mississippian Lime assets acquired in October 2012, the addition of production from the Anadarko Basin Acquisition and developmental drilling during 2013. The lower DD&A rate per Boe is attributable to the addition of reserves with the Anadarko Basin Acquisition, as well as overall growth in proved reserves during 2013.

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Impairment of Oil and Gas Properties.

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

Our impairment of oil and gas properties pursuant to the full cost "ceiling test" was $83.5 million, net of taxes, for the year ended December 31, 2014 compared to $319.6 million, net of taxes, for the year ended December 31, 2013. The most significant factors affecting the 2014 impairment, which was recorded in the first quarter of 2014, related to the transfer of unevaluated property costs to the full cost pool. While we did not record a ceiling test impairment during the fourth quarter of 2014 (as SEC case pricing was still favorable at average prices of $94.99/Bbl for oil and $4.35/MMBtu for natural gas), we would have recorded an additional before tax impairment ranging from $600 million to $800 million at December 31, 2014 if we had used current forward strip pricing from February 2015 in the calculation of the present value of future net revenues from oil and gas properties in determining the full cost ceiling limitation. Should commodity prices remain at their current levels, we will be required to recognize future impairments in the carrying value of oil and gas properties and such impairments may be material.

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

Our impairment of oil and gas properties pursuant to the full cost "ceiling test" was $319.6 million, net of taxes, for the year ended December 31, 2013. There was no impairment for the year ended December 31, 2012.

The most significant factors affecting the impairment related to the transfer of unevaluated property costs to the full cost pool during 2013 and negative reserve revisions in our Gulf Coast area. During 2013, we transferred $61.2 million of Gulf Coast unevaluated property costs to the full cost pool based upon our lack of future plans for further evaluation or development of those leases, and $168.4 million of Mississippian unevaluated property costs attributable to leases that expired during 2013 or that we currently intend to allow to expire in 2014. The negative reserve revisions in our Gulf Coast area were mainly attributable to variability in well performance, our decision during the second quarter to halt further development in our West Gordon field and unfavorable cost revisions.

General and Administrative (G&A).

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

Our G&A expenses decreased to $48.7 million for the year ended December 31, 2014 from $53.3 million for the year ended December 31, 2013. The $4.6 million decrease period over period is primarily related to: $2.0 million in additional COPAS recoveries, $11.5 million less in transition services payments (in 2013 and part of 2014, payments were made as a result of the Eagle Property Acquisition and Anadarko Basin Acquisition) and $3.4 million less in other taxes, partially offset by an increase of $10.1 million in employee costs (including salary, bonus, severance related to the Houston office closure and share-based compensation) and $2.2 million of other G&A costs.

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

Our G&A expenses increased to $53.3 million for the year ended December 31, 2013 from $30.5 million for the year ended December 31, 2012. The increase in G&A expenses of $22.8 million, or 75%, was primarily due to salary, benefits, and other expenses of $10.7 million related to the increase in headcount, which increased from 93 full-time employees at December 31, 2012 to 217 full-time employees at December 31, 2013; an increase in payments made under the Eagle Transition Services Agreement of $0.6 million; payments made under the Panther Transition Services Agreement of $10.2 million; and other costs of $1.3 million.

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Acquisition and Transaction Costs.

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

Our acquisition and transaction costs decreased by $7.7 million to $4.1 million for the year ended December 31, 2014 from $11.8 million for the year ended December 31, 2013. For the 2014 period, these costs generally represent our expenses related to the Pine Prairie Disposition discussed above. For the 2013 period, these costs represent our expenses related to the Anadarko Basin Acquisition discussed above.

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

Our acquisition and transaction costs decreased by $3.1 million for the year ended December 31, 2013 from $14.9 million for the year ended December 31, 2012. These total costs of $11.8 million incurred in 2013 represent our expenses through December 31, 2013 related to the Anadarko Basin Acquisition and are primarily attributable to due diligence, legal and other advisory fees that are required to be expensed under US GAAP.

Other.

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

Other operating expenses for the year ended December 31, 2014 were $5.1 million, compared to $0.6 million for the year ended December 31, 2013. These expenses represent the loss on disposal of, or market value adjustments to, field equipment inventory deemed no longer useful to current operations, penalty fees associated with the early termination of a drilling contract, as well as other miscellaneous expenses.

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

Other operating expenses for the year ended December 31, 2013 were $0.6 million, compared to no related costs for the year ended December 31, 2012. These costs represent the loss on disposal of, or market value adjustments to, field equipment inventory deemed no longer useful to current operations.

Other Income (Expense)

	Years Ended December 31,		
	2014	**2013**	**2012**
		(in thousands)	
OTHER INCOME (EXPENSE)			
Interest income	$ 39	$ 33	$ 245
Interest expense	(149,962)	(115,383)	(24,174)
Capitalized Interest	12,414	32,245	11,175
Interest expense net of amounts capitalized	(137,548)	(83,138)	(12,999)
Total other income (expense)	**$ (137,509)**	**$ (83,105)**	**$ (12,754)**

Interest Expense

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

Interest expense, before capitalized interest, for the years ended December 31, 2014 and 2013 was $150.0 million and $115.4 million, respectively. The increase in interest expense was primarily due to a

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full year of interest associated with the 2021 Senior Notes (as discussed below) issued in 2013. Our average outstanding balance under our revolving credit facility was $386.7 million during the year ended December 31, 2014, compared to $252.7 million the year ended December 31, 2013, and related to $12.7 million of the total interest expense of $150.0 million for the year ended December 31, 2014. Of the remainder, $64.9 million was interest incurred under the 2021 Senior Notes, $64.5 million was interest incurred under the 2020 Senior Notes and $7.9 million represented amortization of deferred financing costs. Of the total interest expense, $12.4 million and $32.2 million was capitalized to oil and gas properties, resulting in $137.6 million and $83.1 million in interest expense, net of capitalized interest, for the years ended December 31, 2014 and 2013, respectively.

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

Interest expense (before capitalized interest) for the years ended December 31, 2013 and 2012 was $115.4 million and $24.2 million, respectively. The increase in 2013 interest expense was primarily due to the issuance during 2013 of the 2021 Senior Notes (as discussed below) and a full year of interest expense associated with the 2020 Senior Notes (as discussed below) issued during 2012, in addition to a higher average outstanding balance under our revolving credit facility during the 2013 period. Our average outstanding balance under our revolving credit facility was $252.7 million during the 2013 period, versus $160.0 million for the 2012 period, and related to $7.1 million of the total interest expense of $115.4 million. The remainder of the interest expense for the year ended December 31, 2013, $108.3 million, related to interest expense of $37.8 million on the 2021 Senior Notes, $64.5 million on the 2020 Senior Notes, and amortization of deferred financing costs of $6.0 million. Of total interest expense, $32.2 million and $11.2 million was capitalized, resulting in $83.1 million and $13.0 million in net interest expense for years ended December 31, 2013 and 2012, respectively.

Provision for Income Taxes.

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

Income tax expense was $6.4 million for the year ended December 31, 2014. This represents an application of our estimated effective tax rate (including state income taxes) for the year ended December 31, 2014 of 5.2% to the income incurred throughout the year. The significant reasons for the change from an income tax benefit to an expense during the year ended December 31, 2014 was $157.5 million of net unrealized gains on commodity derivative contracts which resulted in pre-tax book income of $123.3 million.

The effective tax rate of 5.2% for the year ended December 31, 2014 includes the impact of a $39.9 million reduction in the valuation allowance originally established against our federal tax net operating losses ("NOL") attributable to the unrealized hedging gains during 2014 as discussed above.

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

Income tax benefit was $146.5 million for the year ended December 31, 2013. This represents an application of our estimated effective tax rate (including state income taxes) for the year ended December 31, 2013 of 29.9% to the loss incurred throughout the year. The significant reasons for the change from an income tax expense to a benefit during the year ended December 31, 2013 were the absence of a change in tax status charge during 2013 (as this event took place in 2012), and the occurrence of a book loss for the year ended December 31, 2013.

In light of the impairment of oil and gas properties, we have recorded a $45.7 million valuation allowance against our federal and State of Louisiana tax NOLs, as we do not believe that it is more-likely-than-not that this portion of our NOLs are realizable. We believe that the balance of the NOLs are realizable only to the extent of future taxable income primarily related to the excess of book

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carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment.

Liquidity and Capital Resources

Overview

Our financial statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and the satisfaction of liabilities in the normal course of business. The content below and under "Risks, Uncertainties, and Going Concern" above addresses important factors affecting our financial condition, liquidity and capital resources and debt covenant compliance.

As of December 31, 2014, we had available cash of approximately $11 million and availability under our senior reserve based revolving credit facility (the "Credit Facility") of approximately $90 million. If we have a downward revision in estimates of our proved reserves, our borrowing base for our revolving credit facility may be reduced, and as a result, our available liquidity will be reduced. As of December 31, 2014, payments due on our contractual obligations during the next twelve months are greater than $150 million. This includes approximately $130 million of interest payments on our senior notes and other operating expenses such as fixed drilling commitments and operating leases. We believe that our forecasted cash and available credit capacity are not expected to be sufficient to meet our commitments as they come due over the next twelve months and that we will not be able to remain in compliance with our current debt covenants unless we are able to successfully increase our liquidity. We expect we will need to complete certain transactions, including management of our debt capital structure and potential asset sales, to have sufficient liquidity to satisfy these obligations in the long-term.

Liquidity Sufficiency

Our liquidity outlook has changed since December 31, 2014 primarily as a result of the substantial decrease in oil and NGL prices. This has resulted in lower operating cash flows than expected and if commodity prices remain low compared to recent historical prices, will result in future significantly lower levels of operating cash flows as our current hedging contracts expire.

As a result of this commodity price decline and our substantial debt burden, we believe that our forecasted cash and available credit capacity are not expected to be sufficient to meet our commitments as they come due over the next twelve months and that we will not be able to remain in compliance with our current debt covenants unless we are able to successfully increase our liquidity. Additionally, the terms of our Credit Facility and the indentures governing our senior notes require that some or all of the proceeds from certain asset sales be used to permanently reduce outstanding debt, which could substantially reduce the amount of proceeds we retain, and the covenants in these debt instruments impose limitations on the amount and type of additional indebtedness we can incur, which may significantly reduce our ability to obtain liquidity through the incurrence of additional indebtedness. Furthermore, our ability to refinance any of our existing indebtedness on commercially reasonably terms may be materially and adversely impacted by the current conditions in the energy industry and our financial condition.

We are currently pursuing a number of actions including (i) actively managing our debt capital structure, (ii) selling additional assets, (iii) minimizing our capital expenditures, (iv) obtaining waivers or amendments from our lenders, (v) effectively managing our working capital and (vi) improving our cash flows from operations. There can be no assurance that sufficient liquidity can be raised from one or more of these actions or that these actions can be consummated within the period needed to meet certain obligations. Our interest payment obligations are substantial, and we will be required to pay

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approximately $32 million in interest on our 2020 Senior Notes on each of April 1 and October 1 and approximately $32 million in interest on our 2021 Senior Notes on each of June 1 and December 1.

We have obtained a waiver to our Credit Facility waiving any default as a result of delivering an auditors' opinion in connection with our 2014 financial statements that includes a going concern qualification. As we pursue the actions mentioned above to increase liquidity, we may need to negotiate additional waivers or amendments to our Credit Facility or indentures to facilitate those actions. There can be no assurance that the lenders or the holders of our senior notes will agree to any amendment or waiver on acceptable terms and if a default occurs, a failure to do so may provide the lenders the opportunity to accelerate the outstanding debt under these facilities and it would be classified as a current liability on the balance sheet.

The uncertainty associated with our ability to meet our commitments as they come due or to repay our outstanding debt raises substantial doubt about our ability to continue as a going concern. The accompanying financial statements do not include any adjustments related to the recoverability and classification of recorded assets or the amounts and classification of liabilities that might result from the uncertainty associated with our ability to meet our obligations as they come due.

Financial Ratio Covenants

As of December 31, 2014, our ratio of net consolidated indebtedness to EBITDA was 3.7:1.0 and our ratio of current assets to current liabilities was 1.1:1.0. If liquidity concerns are not addressed in the near-term, we may breach the leverage covenant of our Credit Facility in the third quarter of 2015, which currently requires a maximum ratio of net consolidated indebtedness to EBITDA of 4.0:1.0 beginning with the quarter ended March 31, 2015. As of December 31, 2014, we were in compliance with the financial ratio covenants included in our Credit Facility.

Borrowing Base Redetermination

If oil, NGL, and natural gas prices remain depressed or further deteriorate, the borrowing base under our Credit Facility may be reduced. Any reduction in the borrowing base will reduce our available liquidity, and, if the reduction results in the outstanding amount under the facility exceeding the borrowing base, we will be required to repay the deficiency within 30 days or in six equal monthly installments thereafter, at our election. We may not have the financial resources to make any mandatory deficiency principal repayments, which could result in an event of default under our Credit Facility.

Cross Default Provisions

Our debt facilities contain significant cross default and / or cross acceleration provisions where a default under the Credit Facility or one of the indentures could enable the lenders of the other debt to also declare events of default and accelerate repayment of our obligations under those debt instruments. In general, these cross default / cross acceleration provisions are as follows:

- The Credit Facility allows the lenders to declare an event of default if there is an event of default on other indebtedness and that default: (i) is the result of the failure to make any payment when due in respect of other indebtedness having an aggregate principal amount of at least 5% of the then effective borrowing base and such failure continues after the applicable grace or notice period; or (ii) is the result of a failure to perform any condition, covenant or other event and such failure permits the holders of such other indebtedness to cause the acceleration of such other indebtedness.

- The indentures governing the senior notes allow the lenders to declare an event of default if there is an event of default on other indebtedness and that default: (i) is caused by a failure to make any payment of principal prior to the expiration of the grace period following the final maturity date of such indebtedness; or (ii) results in the acceleration of such indebtedness prior to its stated maturity, and, in each case, the principal amount of any such indebtedness, together with the principal amount of any other indebtedness with respect to which an event described herein has occurred, aggregates $50.0 million or more.

Recent Amendments and Waivers

In March 2015, we received a waiver related to the requirement that an unqualified auditors' opinion without an explanatory paragraph in relation to going concern accompany our annual financial statements.

Our Capital Requirements

At December 31, 2014, our liquidity was $101 million, consisting of $90 million of available borrowing capacity under our Revolving Credit Facility and $11 million of cash and cash equivalents.

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. Subject to capital availability, we currently expect to invest between $250 million and $275 million for exploration, development and lease and seismic acquisition in 2015. Additionally, we expect to capitalize between $4 million and $6 million of interest expense during that same period. Our future success in growing proved reserves and production will be highly dependent on our ability to access additional outside sources of capital, via either the debt or equity markets, through growth in our reserve based credit facility or by securing other external sources of funding. As part of that process, on May 1, 2014, we closed on the sale of 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 estimated net proceeds of $147.5 million, of which $131 million was used to reduce amounts outstanding under our Credit Facility, with the remainder retained for transaction expenses and working capital purposes. Additionally, in March 2015, we executed a purchase and sale agreement covering the sale of our remaining producing assets in Louisiana for total consideration of $44 million cash, before customary closing adjustments. Upon closing of this transaction, which is expected to occur by April 30, 2015, the net proceeds therefrom will be used to repay a portion of our outstanding borrowings under our credit facility and for general corporate purposes.

If oil, NGL and natural gas prices remain weak or further deteriorate or a reduction in our oil and natural gas production and reserves occurs, our ability to fund our capital expenditure program would be reduced and our liquidity would be negatively impacted. We plan to continue pursuing additional strategic options that would improve our financial flexibility and provide additional long-term liquidity, including the sale of other non-core assets and possibly joint-ventures or farm-outs on our properties. We are currently unable to predict the timing of any transaction and no assurance can be given that we will reach any agreement with a potential counterparty.

Though we have no current plans to do so, we may from time to time seek to retire, purchase or exchange our outstanding debt in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Significant Sources of Capital

Mandatorily Redeemable Convertible Preferred Units.

In December 2011, Holdings LLC, FR Midstates Holdings LLC ("FR Midstates") and Midstates Petroleum Holdings, Inc. ("Petroleum Inc.") entered into an amended and restated limited liability company agreement, which was later amended in March 2012, to provide for the issuance of up to 65,000, or $65 million in aggregate value, of certain mandatorily redeemable convertible preferred units (the "Preferred Units") between December 15, 2011 and June 10, 2015. During the year ended December 31, 2012, Holdings LLC issued 65,000 Preferred Units to FR Midstates for aggregate cash proceeds of $65.0 million. On April 26, 2012, we used $67.1 million of the proceeds from our initial public offering to redeem the Preferred Units in full, including interest and other charges. As such, at December 31, 2012, the Preferred Units are no longer outstanding. We recorded $2.1 million related to interest expense associated with these Preferred Units for the year ended December 31, 2012. There was no related interest expense for the years ended December 31, 2014 or 2013.

Reserve-based Credit Facility.

Our Credit Facility consists of a $750 million Credit Facility with a borrowing base supported by our Mississippian Lime and Anadarko Basin oil and gas assets. On September 30, 2014, we entered into an Assignment and Borrowing Base Increase Agreement that increased the borrowing base under the Credit Facility from $475 million to $525 million. At December 31, 2014, we had drawn $435.2 million on our Credit Facility and had outstanding letters of credit obligations total $1.4 million.

The Credit Facility matures on May 31, 2018 and borrowings thereunder are secured by substantially all of our oil and natural gas properties and bear interest at LIBOR plus an applicable margin, depending upon our borrowing base utilization, between 2.00% and 3.00% per annum. At December 31, 2014 and 2013, the weighted average interest rate was 2.8% and 2.5%, respectively.

In addition to interest expense, the Credit Facility requires the payment of a commitment fee each quarter. The commitment fee is computed at the rate of either 0.375% or 0.50% per annum based on the average daily amount by which the borrowing base exceeds the outstanding borrowings during each quarter.

The borrowing base under the Credit Facility is subject to semiannual redeterminations in April and October and up to one additional time per six month period following each scheduled borrowing base redetermination, as may be requested by us or the administrative agent, acting on behalf of lenders holding at least two-thirds of the outstanding loans and other obligations. The next scheduled borrowing base redetermination date is April 1, 2015.

Under the terms of the Credit Facility, we are required to repay the amount by which the principal balance of our outstanding loans and our letter of credit obligations exceed our redetermined borrowing base. We are permitted to make such repayment in six equal successive monthly payments commencing 30 days following the administrative agent's notice regarding such borrowing base reduction.

The Credit Facility contains, among other standard affirmative and negative covenants, financial covenants including a maximum ratio of debt to EBITDA (i.e. leverage ratio) and a minimum current ratio (as defined therein) of not less than 1.0 to 1.0. We are required to maintain a leverage ratio of not more than 4.75 to 1.00 for the quarter ending December 31, 2014, and 4.00 to 1.00 for each quarter thereafter.

As of December 31, 2014, we were in compliance with the current ratio and the ratio of debt to EBITDA covenants as set forth in the Credit Facility. Our current ratio at December 31, 2014 was 1.1 to 1.0. At December 31, 2014, our ratio of debt to EBITDA was 3.7 to 1.0.

Initial Public Offering.

On April 25, 2012, we completed our initial public offering. Our net proceeds from the sale of 18,000,000 of our common shares in the initial public offering, after underwriting discounts and commissions, were $220.0 million (or $213.6 million after offering expenses paid directly by us). Of the net proceeds, $67.1 million was used to redeem the Preferred Units, including interest and other charges, and $99.0 million was used to repay a portion of our borrowings under our revolving credit facility. The remaining proceeds were retained to fund the execution of our growth strategy through our drilling program.

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2020 Senior Notes.

On October 1, 2012, we issued $600 million in aggregate principal amount of 10.75% senior notes due 2020 (the "2020 Outstanding Notes") in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act"). On October 29, 2013, substantially all of the 2020 Outstanding Notes were exchanged for an equal principal amount of registered 10.75% senior subordinated notes due 2020 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the "2020 Exchange Notes"). The 2020 Exchange Notes are identical to the 2020 Outstanding Notes except that the 2020 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Annual Report on Form 10-K, the term "2020 Senior Notes" refers to both the 2020 Outstanding Notes and the 2020 Exchange Notes. The 2020 Senior Notes were co-issued on a joint and several basis with our wholly owned subsidiary, Midstates Sub. We do not have any operations or independent assets other than our 100% ownership interest in Midstates Sub and we have no other subsidiaries. The 2020 Senior Notes Indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to us or limit our ability to advance loans to Midstates Sub.

At any time prior to October 1, 2015, we may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2020 Senior Notes with the net proceeds of a public or private equity offering at a redemption price of 110.75% of the principal amount of the 2020 Senior Notes, plus any accrued and unpaid interest up to the redemption date. In addition, at any time before October 1, 2016, we may redeem all or a part of the 2020 Senior Notes at a redemption price equal to 100% of the principal amount of 2020 Senior Notes redeemed plus the Applicable Premium (as defined in the Indenture) at the redemption date, plus any accrued and unpaid interest and Additional Interest (as defined in the Indenture), if any, up to, the redemption date. On or after October 1, 2016, we may redeem all or a part of the 2020 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the Indenture plus accrued and unpaid interest and Additional Interest (as defined in the Indenture), if any, on the 2020 Senior Notes redeemed, up to, the redemption date.

The 2020 Senior Notes Indenture contains covenants that, among other things, restrict our ability to: (i) incur additional indebtedness, guarantee indebtedness or issue certain preferred shares; (ii) make loans, investments and other restricted payments; (iii) pay dividends on or make other distributions in respect of, or repurchase or redeem, capital stock; (iv) create or incur certain liens; (v) sell, transfer or otherwise dispose of certain assets; (vi) enter into certain types of transactions with our affiliates; (vii) consolidate, merge or sell substantially all of our assets; (viii) prepay, redeem or repurchase certain debt; (ix) alter the business we conduct and (x) enter into agreements restricting the ability of our current and any future subsidiaries to pay dividends.

Upon the occurrence of certain change of control events, as defined in the Indenture, each holder of the 2020 Senior Notes will have the right to require that we repurchase all or a portion of such holder's 2020 Senior Notes in cash at a purchase price equal to 101% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

2021 Senior Notes.

On May 31, 2013, we issued $700 million in aggregate principal amount of 9.25% senior notes due 2021 (the "2021 Outstanding Notes") in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. On October 29, 2013, all of the 2021 Outstanding Notes were exchanged for an equal principal amount of registered 9.25% senior subordinated notes due 2021 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the "2021 Exchange Notes"). The 2021 Exchange Notes are identical to the 2021

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Outstanding Notes except that the 2021 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Annual Report on Form 10-K, the term "2021 Senior Notes" refers to both the 2021 Outstanding Notes and the 2021 Exchange Notes. The proceeds from the offering of $700 million (net of the initial purchasers' discount and related offering expenses) were used to fund the Anadarko Basin Acquisition and the related expenses, to pay the expenses related to an amendment to our revolving credit facility, to repay $34.3 million in outstanding borrowings under our Credit Facility, and for general corporate purposes.

The 2021 Senior Notes rank pari passu in right of payment with the 2020 Senior Notes. The 2021 Senior Notes were co issued on a joint and several basis by us and our wholly owned subsidiary, Midstates Sub. The 2021 Senior Notes indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to us or limit our ability to advance loans to Midstates Sub.

Prior to June 1, 2016, we may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes (less the amount of 2021 Senior Notes redeemed pursuant to the preceding paragraph) with the net proceeds of any Equity Offerings at a redemption price of 109.25% of the principal amount of the 2021 Senior Notes redeemed, plus any accrued and unpaid interest, if any, up to the redemption date. In addition, at any time before June 1, 2016, we may redeem all or a part of the 2021 Senior Notes at a redemption price equal to 100% of the principal amount of the 2021 Senior Notes redeemed plus the Applicable Premium (as defined in the Indenture) at the redemption date, plus any accrued and unpaid interest and Additional Interest (as defined in the 2021 Senior Notes Indenture), if any, up to, the redemption date. On or after October 1, 2016, we may redeem all or a part of the 2021 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the 2021 Senior Notes Indenture plus accrued and unpaid interest and Additional Interest (as defined in the 2021 Senior Notes Indenture), if any, on the 2021 Senior Notes redeemed, up to, the redemption date.

The terms of the covenants and change in control provisions in the 2021 Senior Notes Indenture are substantially identical to those of the 2020 Senior Notes discussed above.

Series A Preferred Stock.

On October 1, 2012 we issued 325,000 shares of our Series A Preferred Stock as part of the purchase price paid to complete the Eagle Property Acquisition. The shares of Series A Preferred Stock have an initial liquidation value of $1,000 per share and are convertible into shares of our common stock on or after October 1, 2013. At such time, the Series A Preferred Stock may be converted, in whole but not in part, at the option of the holders of a majority of the outstanding shares of Series A Preferred Stock, into a number of shares of our common stock calculated by dividing the then-current liquidation preference by the conversion price of $13.50 per share. If not previously converted, the Series A Preferred Stock will be subject to mandatory conversion into shares of our common stock on September 30, 2015 at a conversion price based upon the volume weighted average price of our common stock during the 15 trading days immediately prior to the mandatory conversion date, but in no instance will the price be greater than $13.50 per share or less than $11.00 per share. Dividends on the Series A Preferred Stock will accrue at a rate of 8.0% per annum, payable semiannually, at our sole option, in cash or through an increase in the liquidation preference. The issuance of the Series A Preferred Stock to Eagle Energy pursuant to the Eagle Purchase Agreement was approved by our stockholders holding a majority of the outstanding shares of our common stock.

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Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods presented. For information regarding the individual components of our cash flow amounts, please refer to the Audited Consolidated Statements of Cash Flows included under Item 15 of this Annual Report.

Our operating cash flows are sensitive to a number of variables, the most significant of which is the volatility of oil and gas prices. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of these commodities. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

The following information highlights the significant period-to-period variances in our cash flow amounts (table in thousands):

	For the Years Ended December 31,		
	2014	**2013**	**2012**
Net cash provided by operating activities	$ 356,838	$ 227,102	$ 137,249
Net cash used in investing activities	(409,558)	(1,193,846)	(773,608)
Net cash provided by financing activities	31,114	981,029	647,893
Net change in cash	**$ (21,606)**	**$ 14,285**	**$ 11,534**

Cash flows provided by operating activities

Net cash provided by operating activities was $356.8 million, $227.1 million and $137.2 million for the years ended December 31, 2014, 2013 and 2012, respectively. The increase in net cash provided by operating activities for the year ended December 31, 2014 compared to the year ended December 31, 2013 was primarily the result of an increase in oil and natural gas revenues attributable to higher production and favorable working capital changes, partially offset by lower realized commodity prices. The increase in net cash provided by operating activities for the year ended December 31, 2013 compared to the year ended December 31, 2012 was primarily driven by an increase in production in all commodities and an increase in natural gas prices, partially offset by a decrease in oil and NGL prices.

Cash flows used in investing activities

We had net cash used in investing activities of $409.6 million, $1.2 billion and $773.6 million during the years ended December 31, 2014, 2013 and 2012, respectively, as a result of our capital expenditures for drilling, development and acquisition costs. During the year ended December 31, 2014, $561.7 million was spent on our drilling program, partially offset by $147.7 million in proceeds received for the Pine Prairie Disposition, $3.0 million in proceeds received related to the Exploration Agreement with PetroQuest and $1.4 million in other asset sales. During the year ended December 31, 2013, $573.7 million was spent on our drilling program and $620.1 million for the Anadarko Basin Acquisition. The increase in net cash used in investing activities during the year ended December 31, 2013 compared to the year ended December 31, 2012 was primarily due to the Anadarko Basin Acquisition and continued expansion of our drilling programs.

Cash flows provided by financing activities

Net cash provided by financing activities was $31.1 million, $981.0 million and $647.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. For the year ended December 31,

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2014, we had draws on the revolver of $165.0 million and repayments (using a portion of the proceeds from the Pine Prairie Disposition) of $131.0 million. For the year ended December 31, 2013, cash sourced through financing activities was provided primarily from net long-term borrowings of $1.0 billion, consisting of the 2021 Senior Notes of $700 million and borrowings under the revolver of $341.5 million, offset by repayments of our revolving credit facility of $34.3 million. For the year ended December 31, 2012, cash sourced through financing activities was provided primarily from proceeds from our initial public offering of $213.6 million and net long-term borrowings of $459.2 million, consisting of the 2020 Senior Notes of $600 million and advances from our revolving credit facility, offset by repayments of our revolving credit facility during the year. Our long-term debt was $1.7 billion, $1.7 billion and $694.0 million at December 31, 2014, 2013 and 2012, respectively.

Other Items

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2014 (in thousands):

	Payments Due by Period			
	Total	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Revolving credit facility(1)	$ 435,150	$	$ 435,150	$
2020 Senior Notes(2)	970,875	193,500	129,000	648,375
2021 Senior Notes(2)	1,120,875	194,250	129,500	797,125
Drilling contracts(3)	16,698	16,698		
Non-cancellable office lease commitments(3)	9,320	5,675	2,437	1,208
Seismic contracts(3)	3,192	3,192		
Asset retirement obligations(4)	21,599			21,599
Net minimum commitments	**$ 2,577,709**	**$ 413,315**	**$ 696,087**	**$ 1,468,307**

(1) Amount excludes interest on our revolving credit facility as both the amount borrowed and applicable interest rate is variable. As of December 31, 2014, we had $435.2 million of indebtedness outstanding under our revolving credit facility. See Note 9 to our Consolidated Financial Statements.

(2) Amount includes approximately $64.5 million and $64.8 million of interest per year for our 2020 Senior Notes and 2021 Senior Notes, respectively; see Note 9 to our Consolidated Financial Statements.

(3) See Note 15 to our Consolidated Financial Statements for a description of operating lease, drilling contract, seismic contract and other obligations.

(4) Amounts represent our estimate of future asset retirement obligations on a discounted basis. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 8 to our Consolidated Financial Statements.

Critical Accounting Policies and Estimates

We prepare our financial statements and the accompanying notes in conformity with GAAP, which requires our management to make estimates and assumptions about future events that affect the reported amounts in our financial statements and the accompanying notes. We identify certain accounting policies as critical based on, among other things, their impact on the portrayal of our financial condition, results of operations or liquidity and the degree of difficulty, subjectivity and

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complexity in their deployment. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Our management routinely discusses the development, selection and disclosure of each of the critical accounting policies. Following is a discussion of our most critical accounting policies:

Reserves Estimates. Proved oil and gas reserves are the estimated quantities of natural gas, crude oil and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing operating conditions and government regulations. Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and gas properties are also subject to a "ceiling" limitation based in part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Reserves as of December 31, 2014, 2013 and 2012 were calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each month, held flat for the life of the production, except where prices are defined by contractual arrangements.

We have elected not to disclose probable and possible reserves or reserve estimates in this filing.

Revenue Recognition. Our revenue recognition policy is significant because revenue is a key component of the results of operations and of the forward-looking statements contained in the analysis of liquidity and capital resources. We record revenue in the month our production is delivered to the purchaser, but payment is generally received 30 to 90 days after the date of production. At the end of each month, we estimate the amount of production that was delivered to the purchaser and the price that will be received. We use our knowledge of our properties, their historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices and other factors as the basis for these estimates. We record the variances between our estimates and the actual amounts received in the month payment is received.

Share-Based Compensation. We account for share-based compensation awards in accordance with FASB ASC 718, *Compensation Stock Compensation.* We measure share-based compensation cost at fair value and generally recognize the corresponding compensation expense on a straight-line basis over the service period during which awards are expected to vest. We include share-based compensation expense in "General and administrative expense" in our consolidated statements of operations.

Financial Instruments. Our financial instruments consist of cash and cash equivalents, receivables, payables, debt, and commodity derivatives. Commodity derivatives are recorded at fair value. The carrying amount of our other financial instruments approximate fair value because of the short-term nature of the items or variable pricing.

Derivative financial instruments are recorded in our consolidated balance sheets as either an asset or liability measured at estimated fair value. Changes in the derivative's fair value are recognized currently in earnings as gains and losses in the period of change. The gains or losses are recorded within revenues in "Gains (losses) on commodity derivative contracts net." The related cash flow impact is reflected within cash flows from operating activities.

Asset Retirement Obligations. We have obligations to remove tangible equipment and facilities associated with our oil and natural gas wells, and to restore land at the end of oil and natural gas production operations. The removal and restoration obligations are associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlements and changes in the legal, regulatory, environmental and political environments.

Recent Accounting Pronouncements. We reviewed recently issued accounting pronouncements that became effective during the year ended December 31, 2014, and determined that none would have a material impact on our condensed consolidated financial statements, with the exception of ASU 2014-09, "Revenue from Contracts with Customers" and ASU 2014-15, "Presentation of Financial Statements Going Concern," (both effective for annual reporting periods beginning after December 15, 2016), which we are still evaluating.

Off-Balance Sheet Arrangements. Currently, we do not have any off-balance sheet arrangements as defined under Item 303(a)(4) (ii) of Regulation S-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses or gains, but rather indicators of reasonably possible losses or gains. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. These derivative instruments are discussed in Note 5 to our Consolidated Financial Statements.

Commodity price exposure. We are exposed to market risk as the prices of oil and natural gas fluctuate due to changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged in the past a portion of our production and expect to continue hedging a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil, NGLs and natural gas prices. As of December 31, 2014, we utilized fixed price swaps to reduce the volatility of oil and natural gas prices on a portion of our future expected production.

For derivative instruments recorded at fair value, the credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet.

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The following is a summary of our commodity derivative contracts as of December 31, 2014:

	Hedged Volume	Weighted-Average Fixed Price
Oil (Bbls):		
WTI Swaps 2015	3,276,000	$ 88.72
Natural Gas (MMBtu):		
Swaps 2015(1)	20,050,000	$ 4.15

(1) Includes 2,170,000 MMBtu in natural gas swaps that priced during the period, but had not cash settled as of December 31, 2014.

	Year Ended December 31, 2014 (in thousands)
Derivative fair value at period end asset (included in balance sheet)	$ 126,709
Realized net loss (included in the statement of operations)	$ (18,332)
Unrealized net gain (included in the statement of operations)	$ 157,521

As of December 31, 2014, 2013 and 2012, assets and liabilities recorded at fair value in the balance sheets were categorized based upon the level of judgment associated with the inputs used to measure their value. Our only financial assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2014, 2013 and 2012 are the derivative instruments discussed above. At December 31, 2014 and 2013, all of our commodity derivative contracts were with seven counterparties, respectively, and are all classified as Level 2. Our policy is to net derivative liabilities and assets where there is a legally enforceable master netting agreement with the counterparty.

Interest rate risk. At December 31, 2014, we had indebtedness outstanding under our credit facility of $435.2 million, which bore interest at floating rates, $600 million outstanding in 2020 Senior Notes, which bore interest at 10.75%, and $700 million outstanding in 2021 Senior Notes which bore interest at 9.25%. The average annual interest rate incurred on total indebtedness for the years ended December 31, 2014, 2013 and 2012 was approximately 8.4%, 8.7% and 6.7%, respectively. A 1.0% increase in each of the average LIBOR and federal funds rate for the years ended December 31, 2014 and 2013 would have resulted in an estimated $3.9 million and $2.1 million, respectively, increase in interest expense, of which a portion may be capitalized.

At December 31, 2014, we do not have any interest rate derivatives in place. In the future, we may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Counterparty and customer credit risk. Joint interest receivables arise from billing entities that own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers, including Plains Marketing, Semgas, Phillips66 and Valero Marketing. See "Business Marketing and Major Customers" for further detail about our significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties.

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While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, the financial ability of the customer's parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. The counterparties on our current derivative instruments are lenders under our revolving credit facility with investment grade ratings, and we are likely to enter into any future derivative instruments with these or other lenders under our revolving credit facility which also carry investment grade ratings. Several of our significant customers for oil and gas receivables have a credit rating below investment grade or do not have rated debt securities. In these circumstances, we have considered the lack of investment grade credit rating in addition to the other factors described above.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated Financial Statements, together with the report of our independent registered public accounting firm begin on page F-1 of this Annual Report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2014 at the reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting. The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) and 15d-15(f). Internal control over financial reporting is defined as a process designed by, or under the supervision of, the issuer's principal executive and principal financial officers, or persons performing similar functions, and effected by the Company's board of directors, management, and other personnel, to provide reasonable assurance regarding reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures which (a) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of assets of the Company, (b) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorizations of management and the board of directors, and (c) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of The Treadway Commission. Based on our evaluation under the *Internal Control Integrated Framework (2013)*, our management concluded that our internal control over financial reporting was effective as of December 31, 2014.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2014. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Remediation of Material Weakness. As discussed in our 2013 Form 10-K, our management concluded that our internal control over financial reporting was not effective as of December 31, 2013 as a result of a material weaknesses related to the internal control over the preparation of oil and gas reserve estimates. Management identified the following measures to strengthen our internal control over financial reporting and to address the material weakness. We began implementing certain of these measures in the second quarter of 2014 and continued to develop remediation plans and implemented additional measures throughout the remainder of the year, including:

- Redesigned controls over management's review of oil and gas reserve estimates to ensure an appropriate level of precision to address the associated risks;

- Expanded documentation of the procedures for reviewing the financial, production and ownership data used as inputs into the oil and gas reserve estimate calculations and for retaining evidence when such review is performed;

- Implemented a process for documenting the key decisions and assumptions made by the Company operations personnel during the reconciliation of the oil and gas reserve estimate output between management's internal calculations and the third party reserve engineering firms' calculations; and

- Trained the reserves engineering staff on the above procedures.

Changes in Internal Control over Financial Reporting. Except for the remediation of the previously identified material weakness discussed above, there were no other changes in internal control over financial reporting during the quarter ended December 31, 2014 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Midstates Petroleum Company, Inc.
Houston, Texas

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

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2014 of Midstates and our report dated March 16, 2015 expressed an unqualified opinion on those consolidated financial statements and includes an explanatory paragraph regarding going concern uncertainty.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 16, 2015

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ITEM 9B. OTHER INFORMATION

None.

PART III.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANCE

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

PART IV.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

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(3) Exhibits:

The following documents are included as exhibits to this report:

2.1 Master Reorganization Agreement, dated April 24, 2012, by and among the Company and certain of its affiliates, certain members of the Company's management and certain affiliates of First Reserve Corporation (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).

2.2 Purchase and Sale Agreement, dated as of April 3, 2013, by and among Midstates Petroleum Company LLC, Panther Energy Company, LLC, Red Willow Mid-Continent, LLC and Linn Energy Holdings, LLC (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on April 4, 2013, and incorporated herein by reference).

3.1 Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).

3.2 Certificate of Amendment of the Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Appendix A to the Company's 2014 Proxy Statement filed on April 8, 2014 and incorporated by reference.)

3.3 Amended and Restated Bylaws of Midstates Petroleum Company, Inc. (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).

3.4 Certificate of Designations of Series A Mandatorily Convertible Preferred Stock of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).

4.1 Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A on February 29, 2012, and incorporated herein by reference).

4.2 Indenture, dated October 1, 2012, by and among the Company, Midstates Petroleum Company LLC and Wells Fargo Bank, National Association, as trustee, governing the 10.75% senior notes due 2020 (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).

4.3 Registration Rights Agreement, dated October 1, 2012, by and among the Company, Midstates Petroleum Company LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein, relating to the 10.75% senior notes due 2020 (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).

4.4 Registration Rights Agreement, dated October 1, 2012, by and among the Company, Eagle Energy Production, LLC, FR Midstates Interholding, LP and certain other of the Company's stockholders (filed as Exhibit 4.3 to the Company's Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).

4.5 Indenture, dated May 31, 2013, by and among the Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and the Well Fargo Bank, National Association, as trustee, governing the 9.25% senior notes due 2021 (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on June 3, 2013, and incorporated herein by reference).

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4.6 Registration Rights Agreement, dated May 31, 2013, by and among the Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and Morgan Stanley & Co. LLC and SunTrust Robinson Humphrey, Inc., as representatives of the several initial purchasers named therein, relating to the 9.25% senior notes due 2021 (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on June 3, 2013, and incorporated herein by reference).

10.1 Stockholders' Agreement among the Company and certain equity owners (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).

10.2 Second Amended and Restated Credit Agreement, dated as of June 8, 2012, among the Company, Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lender parties thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 13, 2012, and incorporated herein by reference).

10.3 Assignment and First Amendment to the Second Amended and Restated Credit Agreement, dated as of September 7, 2012, among the Company, Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 12, 2012, and incorporated herein by reference).

10.4 Amendment to First Amendment to the Second Amended and Restated Credit Agreement, dated as of September 26, 2012, among the Company, Midstates Petroleum Company LLC, SunTrust Bank, as administrative agent, and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 27, 2012, and incorporated herein by reference).

10.5 Second Amendment to Second Amended and Restated Credit Agreement, dated as of March 19, 2013, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank, as administrative agent, and the other lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 22, 2013, and incorporated herein by reference).

10.6 Assignment and Third Amendment to the Second Amended and Restated Credit Agreement, dated as of May 20, 2013, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 22, 2013, and incorporated herein by reference).

10.7 Assignment and Fourth Amendment to the Second Amended and Restated Credit Agreement, dated as of September 26, 2013, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 30, 2013, and incorporated herein by reference).

10.8 Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of June 8, 2012, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lender parties thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 3, 2014, and incorporated herein by reference).

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10.9	Assignment and Borrowing Base Increase Agreement, amending the Second Amended and Restated Credit Agreement, dated as of September 30, 2014, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 2, 2014, and incorporated herein by reference).
10.10	Asset Purchase Agreement, dated as of August 11, 2012, among the Company, Midstates Petroleum Company, LLC and Eagle Energy Production, LLC (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on August 13, 2012, and incorporated herein by reference).
10.11	Purchase and Sale Agreement, dated as of March 5, 2014, by and among Midstates Petroleum Company LLC and Tana Exploration Company LLC (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on March 11, 2014, and incorporated herein by reference).
10.12	Purchase and Sale Agreement, dated as of October 2, 2014, by and among Midstates Petroleum Company LLC and Baseline Energy Resources, LLC (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on October 7, 2014, and incorporated herein by reference).
10.13**	Executive Employment Agreement dated as of April 25, 2012 between the Company and Nelson Haight (filed as Exhibit 10.10(a) to the Company's Annual Report on Form 10-K filed on March 24, 2014, and incorporated herein by reference).
10.14**	Amendment to Executive Employment Agreement dated as of December 12, 2013 between the Company and Nelson Haight (filed as Exhibit 10.10(a) to the Company's Annual Report on Form 10-K filed on March 24, 2014, and incorporated herein by reference).
10.15**	Separation and Release Agreement, dated as of October 3, 2013 between Midstates Petroleum Company, Inc. and Stephen C. Pugh (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 4, 2013, and incorporated herein by reference).
10.16**	Separation Agreement and General Release of Claims, dated as of March 19, 2014, between Midstates Petroleum Company, Inc. and John A. Crum (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 20, 2014, and incorporated herein by reference).
10.17**	Employment Agreement, dated effective December 29, 2014, between Midstates Petroleum Company, Inc. and Mark E. Eck (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 24, 2014, and incorporated herein by reference).
10.18**	Separation Agreement and General Release of Claims, dated effective January 1, 2015, between Midstates Petroleum Company, Inc. (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on December 24, 2014 and incorporated herein by reference).
10.19**	Midstates Petroleum Company Inc. 2012 Long Term Incentive Plan (filed as Exhibit 4.3 to the Company's Registration Statement on Form S-8 on April 20, 2012, and incorporated herein by reference).

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10.20**	Midstates Petroleum Company Inc. 2012 Amended and Restated Long Term Incentive Plan (filed as Exhibit 4.4 to the Company's Registration Statement on Form S 8 on May 27, 2014, and incorporated herein by reference).
10.21**	Midstates Petroleum Company, Inc. 2012 Long-Term Incentive Plan Form of Restricted Stock Agreement (Time Vesting) for 2012 Awards (filed as Exhibit 10.10 to the Company's Registration Statement on Form S-1/A on January 20, 2012, and incorporated herein by reference).
10.22**	Midstates Petroleum Company, Inc. 2012 Long-Term Incentive Plan Form of Restricted Stock Agreement (Time Vesting) for 2013 Awards (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on February 27, 2013, and incorporated herein by reference).
10.23**	Midstates Petroleum Company, Inc. Form of Notice of Grant of Restricted Stock (Time Vesting) (filed as Exhibit 10.11 to the Company's Registration Statement on Form S-1/A on January 20, 2012, and incorporated herein by reference).
10.24**	Form of Indemnification Agreement between the Company and each of the directors and executive officers thereof (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1/A on February 16, 2012, and incorporated herein by reference).
10.25	Form of Cash Retention Award (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on June 9, 2014, and incorporated herein by reference).
12.1(a)	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1(a)	List of subsidiaries of the Company.
23.1(a)	Consent of Deloitte & Touche LLP.
23.2(a)	Consent of Netherland, Sewell and Associates, Inc. Independent Petroleum Engineers
23.3(a)	Consent of Cawley, Gillespie & Associates, Inc. Independent Petroleum Engineers
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
99.1(a)	Report of Netherland, Sewell & Associates, Inc.
99.2(a)	Report of Cawley, Gillespie & Associates, Inc.
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Schema Document.
101.CAL(a)	XBRL Calculation Linkbase Document.
101.DEF(a)	XBRL Definition Linkbase Document.
101.LAB(a)	XBRL Labels Linkbase Document
101.PRE(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith

(b)
Furnished herewith

**
Management contract or compensatory plan or arrangement

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

MIDSTATES PETROLEUM COMPANY, INC.

Dated: March 16, 2015

/s/ DR. PETER J. HILL

Dr. Peter J. Hill
Interim President and Chief Executive Officer
(Principal Executive Officer)

Dated: March 16, 2015

/s/ NELSON M. HAIGHT

Nelson M. Haight
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

Dated: March 16, 2015

KNOWN ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Dr. Peter J. Hill and Nelson M. Haight, each of whom may act without joinder of the other, as their true and lawful attorneys-in-fact and agents, each with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ DR. PETER J. HILL Dr. Peter J. Hill	Interim President and Chief Executive Officer (principal executive officer)	March 16, 2015
/s/ NELSON M. HAIGHT Nelson M. Haight	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	March 16, 2015
/s/ FREDERIC F. BRACE Frederic F. Brace	Director	March 16, 2015

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Signatures	Title	Date
/s/ ALAN J. CARR Alan J. Carr	Director	March 16, 2015
/s/ GEORGE A. DEMONTROND George A. Demontrond	Director	March 16, 2015
/s/ THOMAS C. KNUDSON Thomas C. Knudson	Director	March 16, 2015
/s/ LOREN M. LEIKER Loren M. Leiker	Director	March 16, 2015
/s/ JOHN MOGFORD John Mogford	Director	March 16, 2015
/s/ MARY P. RICCIARDELLO Mary P. Ricciardello	Director	March 16, 2015
/s/ ROBERT M. TICHIO Robert M. Tichio	Director	March 16, 2015

MIDSTATES PETROLEUM COMPANY, INC.
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Midstates Petroleum Company, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Midstates Petroleum Company, Inc. and subsidiary ("Midstates") as of December 31, 2014 and 2013, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of Midstates' management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Midstates Petroleum Company, Inc. and subsidiary as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming that Midstates will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, Midstates' projected debt covenant violation and resulting lack of liquidity raise substantial doubt about its ability to continue as a going concern. Management's plans concerning these matters are also discussed in Note 2 to the consolidated financial statements. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Midstates' internal control over financial reporting as of December 31, 2014, based on the criteria established in Internal Control Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 16, 2015 expressed an unqualified opinion on Midstates' internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 16, 2015

MIDSTATES PETROLEUM COMPANY, INC.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share amounts)

	December 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 11,557	$ 33,163
Accounts receivable:		
Oil and gas sales	69,161	102,483
Joint interest billing	42,407	42,631
Other	22,193	1,090
Commodity derivative contracts	126,709	700
Deferred income taxes		11,837
Other current assets	1,098	693
Total current assets	273,125	192,597
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of full-cost accounting	3,442,681	3,060,661
Other property and equipment	13,454	11,113
Less accumulated depreciation, depletion, amortization and impairment	(1,333,019)	(976,880)
Net property and equipment	2,123,116	2,094,894
OTHER ASSETS:		
Commodity derivative contracts		19
Deferred income taxes	35,821	
Other noncurrent assets	43,731	54,597
Total other assets	79,552	54,616
TOTAL	**$ 2,475,793**	**$ 2,342,107**
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 22,783	$ 21,493
Accrued liabilities	183,831	204,381
Commodity derivative contracts		27,880
Deferred income taxes	44,862	
Total current liabilities	251,476	253,754
LONG-TERM LIABILITIES:		
Asset retirement obligations	21,599	26,308
Commodity derivative contracts		3,651
Long-term debt	1,735,150	1,701,150
Deferred income taxes		15,291
Other long-term liabilities	1,706	1,954
Total long-term liabilities	1,758,455	1,748,354
COMMITMENTS AND CONTINGENCIES (Note 15)		
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.01 par value, 49,675,000 shares authorized; no shares issued or outstanding		

Series A mandatorily convertible preferred stock, $0.01 par value, $387,808 and $358,550 liquidation value at December 31, 2014 and December 31, 2013, respectively; 8% cumulative dividends; 325,000 shares issued and outstanding	3	3
Common stock, $0.01 par value, 300,000,000 shares authorized; 70,491,732 shares issued and 69,957,055 shares outstanding at December 31, 2014 and 68,925,745 shares issued and 68,807,043 shares outstanding at December 31, 2013	704	689
Treasury stock	(2,592)	(664)
Additional paid-in-capital	881,894	871,047
Retained deficit	(414,147)	(531,076)
Total stockholders' equity	465,862	339,999
TOTAL	**$ 2,475,793**	**$ 2,342,107**

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