MIDSTATES PETROLEUM

2015 Annual Report

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to .

Commission File Number: 001-35512

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	**Not Applicable**
(Title of each class)	(Name of each exchange on which registered)

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

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

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

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

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

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

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $42.0 million based upon the closing price of such stock on June 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, of $9.30 per share.

The number of shares outstanding of our stock at March 28, 2016 is shown below:

Class	**Number of shares outstanding**
Common stock, $0.01 par value	10,798,029

DOCUMENTS INCORPORATED BY REFERENCE

None.

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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;
- current and future ability to dispose of salt water;
- 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 reserve based revolving credit facility (the “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 and Texas;
- 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 continued to experience significant declines throughout 2015. The extended decline in oil and natural gas prices has had, and will continue to have, a material adverse effect on our financial position, results of operations, cash flows and access to capital. Also, new risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make.

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

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

Boe/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.

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. is an independent exploration and production company focused on the application of modern drilling and completion techniques in oil and liquids-rich basins in the onshore United States. Our operations are concentrated in Oklahoma and Texas, with our corporate headquarters located in Tulsa, Oklahoma. Our common stock was listed on the New York Stock Exchange (the "NYSE") in 2012 under the symbol "MPO"; however, we were delisted by the NYSE on February 3, 2016 and now trade on the over the counter market under the symbol "MPOY".

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.

In October 2012, the Company closed on the acquisition of all of Eagle Energy Production, LLC's producing properties and undeveloped acreage, located primarily in the Mississippian Lime liquids play in Oklahoma. In May 2013, the Company completed an acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company. In May 2014, the Company closed on the divestiture of all of its ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana ("Pine Prairie Disposition"). In April 2015, the Company completed the divestiture of its remaining producing properties in Louisiana with the sale of its Dequincy assets and as of December 31, 2015, the Company has no proved reserves or production in its Gulf Coast operating area.

The following table summarizes, by areas of operation, our estimated proved reserves as of December 31, 2015, their corresponding pre-tax PV-10 values and our fourth quarter 2015 average daily production rates:

	Proved Reserves(1)						Average Daily Production for Three Months Ended
	Oil (MBbl)	**NGL (MBbl)**	**Gas (MMcf)**	**Total(2) (MBoe)**	**% Oil(4)**	**PV-10(3) (in thousands)**	**December 31, 2015 (Boe/day)**
Areas of Operation							
Mississippian	21,115	14,119	176,255	64,610	55%	$452,217	25,222
Anadarko	3,598	2,126	19,237	8,930	64%	60,602	5,668
Total	**24,713**	**16,245**	**195,492**	**73,540**	56%	**512,819**	**30,890**
Discounted Future Income Taxes						—	
Standardized Measure of Discounted Future Net Cash Flows(3)						$**512,819**	

(1) Pursuant to SEC requirements, 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, 2015. These prices were $50.28/Bbl for oil and $2.59/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 is 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 2015, we incurred the following operational and total capital expenditures:

	For the Three Months Ended December 31, 2015	**For the Twelve Months Ended December 31, 2015**
	(in thousands)	
Drilling and completion activities	$45,394	$258,936
Acquisition of acreage and seismic data	3,636	8,448
Operational capital expenditures incurred	**$49,030**	**$267,384**
Capitalized G&A, Office, ARO, & Other	3,518	11,182
Capitalized interest	1,935	4,860
Total capital expenditures incurred	**$54,483**	**$283,426**

As noted above, we incurred operational capital expenditures of $267.4 million during the year ended December 31, 2015, of which $257.3 million was spent in the Mississippian Lime, $8.0 million was spent in the Anadarko Basin and $2.1 million was spent in the Gulf Coast area.

Strategies

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 operations. For 2016, we plan to allocate substantially all of our drilling and completions capital budget to development activities in the Mississippian area based on the 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. At December 31, 2015, we had approximately 103,729 gross (81,844 net) acres under lease in the area, comprised of approximately 83,842 gross (69,680 net) leased acres in the Mississippian Lime and approximately 19,887 gross (12,164 net) acres in the Hunton. As of December 31, 2015, we had three drilling rigs in operation. We anticipate decreasing to one drilling rig by the end of March 2016.

- *Anadarko Basin.* Our Anadarko Basin assets acquired on May 31, 2013 are located in Western Oklahoma and Texas and target multiple horizons in the Pennsylvanian section. Our acreage includes the Cleveland, Marmaton, Cottage Grove and Tonkawa formations and can be accessed utilizing horizontal wells and multi-stage frac technology. At December 31, 2015, we had approximately 144,989 gross (111,190 net) acres under lease in the Anadarko Basin, comprised of approximately 46,193 gross (28,657 net) leased acres in Oklahoma and approximately 98,796 gross (82,533 net) acres in Texas. We did not spud any wells in this area during 2015 and we do not expect to spud any wells on this acreage during 2016. We intend to continue to evaluate this prospective acreage for future drilling plans if commodity prices recover and/or drilling and completion costs experience sustained improvement.

- *Gulf Coast.* As of December 31, 2015, we had minimal acreage in the Gulf Coast. We currently expect no future development activity in the Gulf Coast.

Summary of Oil and Gas Properties and Operations

Mississippian Lime

At December 31, 2015, our Mississippian Lime assets consisted of approximately 69,680 net prospective acres in the Mississippian Lime trend in Woods and Alfalfa Counties of Oklahoma which we currently intend to develop using horizontal wells, and approximately 12,164 net acres in Lincoln County, Oklahoma, which produces from, and is prospective in, the Hunton formation.

Our properties in this area represented 88% of our total proved reserves as of December 31, 2015. As of December 31, 2015, we held an average working interest and average net revenue interest of 73% and 58%, respectively, in this area.

For the three months ended December 31, 2015 and 2014 and the years ended December 31, 2015 and 2014, our average daily production from this area was as follows:

	Three Months Ended December 31,			Years Ended December 31,		
	2015	2014	Increase (Decrease) in Production	2015	2014	Increase in Production
Average daily production:						
Oil (Bbls)	9,158	10,060	(9)%	10,194	8,411	21%
Natural gas liquids (Bbls)	5,188	4,809	8%	5,307	4,437	20%
Natural gas (Mcf)	65,260	61,025	7%	64,688	52,024	24%
Net Boe/day	25,222	25,039	1%	26,282	21,518	22%

During 2015, we invested approximately $257.3 million and spud 67 net horizontal wells in this region. In the three months ended December 31, 2015, we spud 14 net wells and brought 15 net wells online. Of the 14 net wells spud during the quarter, 7 were awaiting completion and 7 were producing at year-end.

Anadarko Basin

At December 31, 2015, our Anadarko Basin assets consisted of approximately 111,190 net acres in the Anadarko Basin, with 82,533 net acres in Texas and 28,657 net acres in western Oklahoma. As of December 31, 2015, we did not have any drilling rigs in operation in this area.

Our properties in this area represented 12% of our total proved reserves as of December 31, 2015. As of December 31, 2015, we held an average working interest and average net revenue interest of 63% and 50%, respectively, in this area.

For the three months ended December 31, 2015 and 2014 and the years ended December 31, 2015 and 2014, our average daily production from this area was as follows:

	Three Months Ended December 31,			Years Ended December 31,		
	2015	2014	Decrease in Production	2015	2014	Decrease in Production
Average daily production:						
Oil (Bbls)	2,165	3,343	(35)%	2,680	4,014	(33)%
Natural gas liquids (Bbls)	1,479	1,703	(13)%	1,388	1,766	(21)%
Natural gas (Mcf)	12,145	13,749	(12)%	12,921	14,930	(13)%
Net Boe/day	5,668	7,337	(23)%	6,222	8,269	(25)%

Due to the current commodity price and drilling and completion cost environment, we did not spud any wells on this acreage during 2015. For 2016, our efforts will focus on reducing well maintenance and operating 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

On April 21, 2015, we closed on the sale of certain of our oil and gas properties in Beauregard and Calcasieu Parishes, Louisiana (the "Dequincy Divestiture"), for approximately $44.0 million, before customary post-closing adjustments. We have no proved reserves or production in the Gulf Coast as of December 31, 2015.

For the quarter ended December 31, 2015 and 2014, and years ended December 31, 2015 and 2014, our average daily production from the area was as follows:

	Three Months Ended December 31,			Years Ended December 31,		
	2015(1)	2014	Decrease in Production	2015(1)	2014(2)	Decrease in Production
Average daily production:						
Oil (Bbls)	—	959	(100)%	260	1,669	(84)%
Natural gas liquids (Bbls)	—	278	(100)%	81	419	(81)%
Natural gas (Mcf)	—	911	(100)%	208	1,574	(87)%
Net Boe/day	—	1,388	(100)%	376	2,350	(84)%

(1) The Dequincy Divestiture closed on April 21, 2015.

(2) The Pine Prairie Disposition closed on May 1, 2014.

<u>Reserves Information</u>

Estimated Proved Reserves

The following table sets forth our estimated net proved reserves expressed by product as of December 31, 2015, 2014 and 2013:

	As of December 31, 2015	As of December 31, 2014	As of December 31, 2013
Estimated proved reserves:			
Oil (MBbls)	24,713	58,242	54,899
Natural gas liquids (MBbls)	16,245	32,528	26,156
Natural gas (MMcf)	195,492	377,845	280,198
Total estimated proved reserves (MBoe)	73,540	153,744	127,755
Proved developed (MBoe)	69,110	73,620	48,743
Proved undeveloped (MBoe)	4,430	80,124	79,012
Percent proved developed reserves	94%	48%	38%

Proved Undeveloped Reserves

Our estimated proved undeveloped reserves decreased from approximately 80,124 MBoe at December 31, 2014 to approximately 4,430 MBoe at December 31, 2015. The following table summarizes the changes in our estimated proved undeveloped reserves during 2015 (in MBoe):

Proved undeveloped reserves, December 31, 2014	80,124
Purchases of reserves in place	—
Sales of reserves	—
Extensions and discoveries	2,690
Revisions of previous estimates	(60,989)
Conversion to proved developed reserves	(17,395)
Proved undeveloped reserves, December 31, 2015	4,430

Due to uncertainty regarding our ability to finance the development of all our proved undeveloped reserves over a five year period, 77,362 MBoe of proved undeveloped reserves, comprising $179.0 million of PV-10 value (at SEC pricing), have been transferred and booked in the probable reserve category as of December 31, 2015.

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, 2015 and 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. Additionally, our estimated reserves and related future net revenues at December 31, 2013 for the Anadarko area are based on reports prepared by 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 for the periods indicated above 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 28 years of practical experience in petroleum engineering, with over 26 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, as well as our estimated reserves and related future net revenues for the Gulf Coast area at December 31, 2014 and 2013, were 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.

The reserves estimates shown herein for the periods indicated above have been independently evaluated by 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. 71658), 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 have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, 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 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. 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.

At December 31, 2015, Joseph Awny, our Director of Corporate Reserves and Reservoir Engineering, was primarily responsible for overseeing the preparation of our reserve estimates and reported directly to the Chief Executive Officer. Mr. Awny has more than 35 years of experience in reserve estimation and evaluation of oil and gas assets. Mr. Awny spent most of his career with Equitable Resources, where he held the positions of Manager of Coalbed Methane Development and Engineering Manager responsible for Corporate Reserves and Business Planning and headed the evaluation of Statoil's Appalachian Properties Acquisition. Prior to joining Midstates Mr. Awny had been Senior Reservoir Engineer with SM Energy and Sr. District Engineer with Samson Resources in Tulsa. Mr. Awny graduated from West Virginia University in 1977 with a B.S degree in Petroleum Engineering.

Production, revenues and price history

Oil, NGLs and natural gas are commodities. The price that we receive for the oil, NGLs and natural gas we produce is largely a function of market supply and demand. The price of oil substantially declined in the fourth quarter of 2014 and remained depressed throughout 2015 due to a variety of macro-economic factors. A continued substantial or extended decline in oil or natural gas prices has had, and could continue to 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. For additional information on these and other risks, see information set forth in "Risk Factors".

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, 2015, 2014 and 2013. For additional details, see information set forth in “Management’s Discussion and Analysis of Financial Condition and Results of Operation.”

	Years Ended December 31,		
	2015	2014	2013
Operating Data:			
Net production volumes:			
Oil (MBbls)	4,794	5,144	3,904
NGLs (MBbls)	2,473	2,417	1,719
Natural gas (MMcf)	28,403	25,013	18,657
Total oil equivalents (MBoe)	12,001	11,730	8,733
Average daily production (Boe/d)	32,880	32,137	23,927
Average Sales Prices:			
Oil, without realized derivatives (per Bbl)	$45.40	$90.71	$99.18
Oil, with realized derivatives (per Bbl)	$74.74	$87.40	$93.41
Natural gas liquids, without realized derivatives (per Bbl)	$15.46	$36.31	$36.26
Natural gas liquids, with realized derivatives (per Bbl)	$15.46	$36.40	$37.09
Natural gas, without realized derivatives (per Mcf)	$2.35	$3.97	$3.39
Natural gas, with realized derivatives (per Mcf)	$3.30	$3.91	$3.58
Costs and Expenses (per Boe of production):			
Lease operating and workover	$6.79	$6.79	$8.41
Gathering and transportation	$1.30	$1.14	$0.62
Severance and other taxes	$0.72	$2.07	$3.12
Asset retirement accretion	$0.13	$0.15	$0.17
Depreciation, depletion and amortization	$16.55	$23.01	$28.67
Impairment of oil and gas properties	$135.47	$7.37	$51.91
General and administrative	$3.22	$4.15	$6.10
Acquisition and transaction costs	$0.03	$0.35	$1.35
Debt restructuring costs and advisory fees	$3.01	$—	$—
Other	$0.18	$0.44	$0.07

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, 2015, 2014 and 2013:

	Years Ended December 31,		
	2015	2014	2013
Mississippian(1)			
Daily production volumes:			
Oil (Bbls)	10,187	8,401	4,550
NGLs (Bbls)	4,900	4,093	1,908
Natural gas (Mcf)	62,514	50,164	30,070
Total oil equivalents (Net Boe/day)	**25,506**	**20,854**	**11,470**
Anadarko(2)			
Daily production volumes:			
Oil (Bbls)	2,680	4,014	2,239
NGLs (Bbls)	1,388	1,766	1,082
Natural gas (Mcf)	12,921	14,930	9,559
Total oil equivalents (Net Boe/day)	**6,222**	**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, 2015:

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Total productive wells	657	450	92	68	749	518

Productive wells consist of producing wells and wells capable of producing. Gross wells are the total number of productive wells in which we have working interests, and net wells are the sum of our fractional working interests owned in gross wells. Each gross well completed in more than one producing zone is counted as a single well.

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, 2015 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	85,040	67,054	18,689	14,790	103,729	81,844
Anadarko Basin	118,391	94,710	26,598	16,480	144,989	111,190
Gulf Coast	—	—	12,487	11,757	12,487	11,757
Total	**203,431**	**161,764**	**57,774**	**43,027**	**261,205**	**204,791**

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2015 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 2016		Expiring 2017		Expiring 2018	
	Gross	Net	Gross	Net	Gross	Net
Mississippian Lime	6,361	5,841	6,909	5,512	5,420	3,437
Anadarko Basin	7,152	6,239	18,965	10,181	480	60
Gulf Coast	6,638	6,416	5,175	4,736	674	605
Total Undeveloped Acreage Expirations	**20,151**	**18,496**	**31,049**	**20,429**	**6,574**	**4,102**

Approximately 4% of our net acreage, including acreage under option, was acquired in 2015, 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, we may allow leasehold rights on acreage not held by production to expire in this area, which could reduce our future drilling opportunities. Based on current pricing, drilling plans and uncertainty regarding our ability to finance our exploration activities, we moved the entire value of our unevaluated property to the full cost pool during the fourth quarter of 2015.

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2015, 2014 and 2013. 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,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	84	74	119	97	121	98
Dry holes	—	—	—	—	1	1
Total	**84**	**74**	**119**	**97**	**122**	**99**

	Years Ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	—	—	1	1	—	—
Dry holes	3	—	—	—	2	2
Total	3	—	**1**	**1**	**2**	**2**
Total wells	**87**	**74**	**120**	**98**	**124**	**101**

As of December 31, 2015, there were two gross (and net) development wells currently drilling; no exploratory wells were being drilled.

After peaking in 2013, our drilling activity decreased during 2014 and 2015 due to the decline in commodity prices. As of December 31, 2015, we had three drilling rigs in operation. We anticipate decreasing to one drilling rig by the end of March 2016. Our recent drilling activity has primarily focused on development and delineation and appraisal of our primary operating areas in the Mississippian. 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, 2015, we did not have any operated wells that were deemed dry holes. However, as part of our exploration agreement with PetroQuest (discussed further in "—Note 7. Acquisitions and Divestitures of Oil and Gas Properties" to our consolidated financial statements), three wells were drilled and deemed dry holes in the Lower Wilcox during 2015.

Marketing and Major Purchasers

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 the majority of our natural gas production is dedicated to one purchaser for the economic life of the relevant assets. For the year ended December 31, 2015, Plains Marketing and Semgas accounted for 43% and 25% of our revenues, respectively. 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 Markting accounted for 28%, 16%, 13%, 12%, and 11% of our revenues, respectively. Due to the nature of oil, NGLs and natural gas 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 are 5,460 Bbls per day for each monthly accounting period over the remaining term of the contract. Additionally, we were 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 have resulted 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 have resulted 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 December 31, 2015, we have delivered the total volumes required for both the 30 months and 60 months, as specified. We are currently delivering at least the minimum volumes required under these contractual provisions.

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 undertake any title curative that is deemed necessary to address any significant title discrepancies. To the extent title opinions or other investigations reflect any such significant defects affecting those properties, we are responsible for curing any such defects at our expense to the extent that any such defect impacts our ownership interest. Likewise, we may choose to notify other owners whose title is subject to a title defect so that they may undertake the necessary efforts to attempt to cure the applicable title defect at their own expense. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to the same 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 generally perform title reviews on the most significant properties and, depending on the materiality of such properties, we may obtain an acquisition title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are generally subject to customary royalty interests or other burdens, and a majority of them are subject to liens to secure borrowings under our Credit Facility and the indentures governing our Second and Third Lien Notes, liens for current taxes and other burdens which we believe do not materially interfere with our ability to operate or develop the same or affect our carrying value of the properties.

Seasonality

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

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

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (“EPAct 2005”). EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1.0 million per day for violations of the NGA and increases the FERC’s civil penalty authority under the NGPA from $5,000 per violation per day to $1.0 million per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, 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 Wall Street Reform and Consumer Protection Act (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 and natural resource protection. Numerous governmental entities, including the U.S. Environmental Protection Agency ("EPA"), analogous state agencies, and, in certain instances, citizens' groups, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close waste pits and plug abandoned wells; (v) impose specific safety and health criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of injunctions prohibiting some or all of our operations. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would 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, waste handling, storage, transport, or disposal requirements, 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 and proposed 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 parties 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 to consider its repeal. Most recently, in August 2015, nonprofit environmental groups filed a notice of intent to sue the EPA regarding its failure to review the RCRA E&P waste exemption. 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 September 2015, the EPA proposed similar rules that would impose volatile organic compounds emissions limits on certain oil and natural gas operations that were previously unregulated, including hydraulically fractured oil wells, as well as methane emissions limits for certain new or modified oil and natural gas emissions sources (the rules are expected to be finalized in June 2016). In addition, the EPA published a final regulation on October 1, 2015 that reduces the National Ambient Air Quality Standard for ozone to between 65 to 70 parts per billion ("ppb") for both the 8-hour primary and secondary standards protective of public health and public welfare. These new regulations 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 our 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 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, the EPA recently proposed 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; the regulations are expected to be finalized in 2016. In addition, the Clean Power Plan, which was announced in August 2015, seeks to reduce carbon dioxide emissions by 32 percent from 2005 levels by 2030; however, on February 9, 2016, the U.S. Supreme Court stayed the implementation of the plan while it is being challenged in court. Furthermore, the U.S. is a party to the Paris Agreement adopted in December 2015 to reduce global greenhouse emissions. 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 contribute to seismic activity in certain areas, including Texas and Oklahoma, where we operate. In response to these concerns, effective on November 17, 2014, the Texas Railroad Commission ("TRC") adopted a new rule governing permitting or re-permitting of disposal wells that requires, 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 a permittee or a prospective permittee fails to demonstrate that the saltwater or other 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 are 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 has released guidance for wells injecting into the Arbuckle formation and is monitoring existing wells for indications that salt water injection may be contributing to significant seismic events. In December 2015, the OCC temporarily shut down six water disposal wells (none of which were our wells) due to two nearby 4.7 magnitude earthquakes.

On November 19, 2015, the Oklahoma Corporation Commission's Oil and Gas Conservation Division ("OGCD") issued a directive to stop or reduce disposal volumes in the Cherokee-Carmen area, including 5 wells we currently operate. On January 13, 2016, the OGCD announced a plan in response to recent earthquakes in the Fairview area of Oklahoma. The plan calls for changes to the operations of oil and gas wastewater disposal wells in the area that dispose into the Arbuckle formation. Under the plan, a total of 27 Arbuckle disposal wells will be required to reduce disposal volume. The plan will affect 7 disposal wells we currently operate in the Arbuckle formation. On February 16, 2016, the OGCD requested we curtail our wastewater disposal volumes by approximately 40%. We are currently in discussions with the OGCD regarding these matters and are working to mitigate any potential impact to our operations.

Hydraulic fracturing activities

Hydraulic fracturing is an important and common industry practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, 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; proposed in April 2015 effluent limit guidelines that saltwater from shale resource extraction operations must meet before discharging to publicly owned wastewater treatment plants (the final rule is expected to be issued in March 2016) 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 (the public comment period on the EPA's advance notice ended in September 2014, and a final notice of proposed rulemaking is expected in 2016). Also, the federal Bureau of Land Management ("BLM") published a final rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands in March 2015. In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing 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, as announced in December 2014, the White House Council on Environmental Quality is coordinating an administration wide review of hydraulic fracturing practices. The EPA commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater in 2011 and issued a draft assessment for public comment and peer review in June 2015; the assessment is expected to be finalized in 2016. The draft assessment concluded that hydraulic fracturing has not led to widespread, systemic impacts on drinking water resources, but it does have the potential to impact drinking water resources; however, this conclusion has recently been criticized by the EPA's Science Advisory Board. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These 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 Safe Drinking Water Act, as amended ("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

The Endangered Species Act restricts activities that may affect endangered and threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Oil and gas activities in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various species and their habitat. Seasonal restrictions could limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which could lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The U.S. Fish and Wildlife Service in May 2014 proposed a rule to alter how it identifies critical habitat for endangered and threatened species. It is unclear when this rule will be finalized. The designation of critical habitat areas could materially restrict use of or access to federal, state and private lands. In addition, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish & Wildlife Service is required to make a determination on the listing of numerous species as endangered or threatened under the Endangered Species Act over the next several years. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures and could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

OSHA

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

Employees

As of December 31, 2015, we employed 159 people, including 59 technical (geosciences, engineering, land), 40 field operations, 56 corporate (finance, accounting, planning, business development, legal, office management) and 4 executive management.

In February 2016, we implemented a workforce reduction of 35 positions.

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 future closure of our Houston office, we are currently working to sublet our Houston office space. We also lease one field office 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 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 or our operations.

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 2016 and our ability to make interest payments in respect of our indebtedness.

The Company's decisions on capital structure, hedging and drilling are based upon widely available information of anticipated future commodity pricing and expected economic conditions. The unexpected substantial decrease in oil and gas prices that began in the second half of 2014 and continued throughout 2015 and into 2016 has resulted in materially lower operating cash flows than expected. The Company's hedging contracts helped to mitigate the impact of lower commodity prices during 2015 as the Company received cash settlements of these derivatives of $167.7 million, which comprised 78.6% of our cash provided by operations during 2015. However, all of the Company's hedging contracts expired during 2015, and as a result, the Company will not receive any cash derivative settlements for 2016 or future periods, which will materially lower cash provided by operations in those future periods as compared to its historical operating cash flows.

The Company has substantial interest payment obligations over the next twelve months related to its debt. As of December 31, 2015, payments due on contractual obligations during the next twelve months were approximately $188.0 million. This includes approximately $179.5 million of interest payments on the Company's long-term debt and other operating expenses such as fixed drilling commitments and operating leases. The Company's next scheduled interest payment is April 1, 2016 for $15.8 million to the holders of the 2020 Senior Notes and the Company is currently evaluating whether such interest payment will be made. If the payment is not made by April 1, 2016, the Company would have 30 days to cure such payment default before an event of default occurs.

In February 2016, the Company borrowed approximately $249.2 million under its Credit Facility, which represented the remaining undrawn amount that was available under the Credit Facility and as a result, as of February 9, 2016, the Company had a cash balance of approximately $335.7 million.

As a result of the sustained commodity price decline and its substantial debt burden, the Company believes that forecasted cash and available credit capacity will not be sufficient to meet commitments as they come due over the next twelve months, and it will not be able to remain in compliance with current debt covenants unless it is able to successfully increase liquidity or deleverage. The uncertainty associated with the ability to meet commitments as they come due or to repay outstanding debt raises substantial doubt about the Company's ability to continue as a going concern. The consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern. The Company's long-term debt is reflected as a current liability in its consolidated balance sheet at December 31, 2015. The classification as a current obligation is based on the uncertainty regarding the Company's ability to comply with certain restrictive covenants contained in its Credit Facility and the related cross default/cross acceleration provisions contained in the Company's Senior Notes (as defined below).

In order to increase the Company's liquidity to levels sufficient to meet the Company's commitments, the Company is currently undertaking a number of actions, including minimizing capital expenditures, aggressively managing working capital and further reducing its recurring operating expenses. The Company believes that even after taking these actions, it will not have sufficient liquidity to satisfy its debt service obligations, meet other financial obligations, and comply with its debt covenants. The Company has engaged financial and legal advisors to assist with analyzing various strategic alternatives to address its liquidity and capital structure, among other things. The Company believes a filing under Chapter 11 of the U.S. Bankruptcy Code may provide the most expeditious manner in which to effect a capital structure solution. There can be no assurance the Company will be able to restructure its capital structure on terms acceptable to the Company and its creditors, or at all.

We may be unable to continue as a going concern.

As mentioned in the risk factor immediately above, we have substantial debt obligations and may not be able to maintain adequate liquidity throughout 2016. As a result, 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.

The report of our independent registered public accounting firm that accompanied our consolidated financial statements for the year ended December 31, 2014 also contained an explanatory paragraph regarding a projected debt covenant violation and resulting lack of liquidity raising substantial doubt about our ability to continue as a going concern; however, we obtained a waiver to the Credit Facility waiving any default as a result of receiving such explanatory paragraph in 2014. We have not received a similar waiver from our Credit Facility for the explanatory paragraph to our 2015 independent registered public accounting firm report. As a result, we are in default under our Credit Facility. A failure to cure this default within 30 days will result in the acceleration of all of our indebtedness under the Credit Facility. If the lenders under our Credit Facility accelerate the loans outstanding thereunder, we will then also be in default under the under the indentures governing our Senior Notes, in which case the lenders under the indentures governing the Senior Notes could accelerate the repayment thereof.

If lenders, and subsequently noteholders, accelerate the Company's outstanding indebtedness, it will become immediately due and payable and the Company will not have sufficient liquidity to repay those amounts. If we are unable to reach an agreement with our creditors prior to any of the above described accelerations, we could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

The Company's long-term debt with maturities summarized in Note 9 in the consolidated financial statements included in this Annual Report on Form 10-K is reflected as a current liability in our accompanying consolidated balance sheet at December 31, 2015. The classification as a current liability is based on the uncertainty regarding our ability to cure the event of default discussed above and to comply with certain restrictive covenants contained in our Credit Facility and cross default/cross acceleration provisions in the indentures governing the Senior Notes.

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

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

- 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.

The recent declines in oil and, to a lesser extent, NGL and natural gas prices has adversely affected our business, financial condition and 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, NGLs and natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. Oil, NGLs 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 these commodities have been volatile, and are likely to continue to be volatile in the future, especially given current economic and geopolitical conditions. The spot oil prices during 2015 ranged from a high of $61.36 to a low of $34.55 per Bbl and the spot natural gas prices during 2015 ranged from a high of $3.32 to a low of $1.63 per MMBtu. Through February 22, 2016, commodity prices have continued to be depressed and volatile relative to past years, with spot oil prices ranging from a high of $36.81 to a low of $26.19 per Bbl and the spot natural gas prices ranging from a high of $2.54 to a low of $1.78 per MMBtu. 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, but are not limited to, the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil, NGLs and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil, NGLs and natural gas;
- political conditions in or affecting other oil, NGL 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;
- foreign, domestic and local governmental regulations and taxes;
- speculation as to the future price of oil, NGLs and natural gas and the speculative trading of oil, NGLs and natural gas futures contracts;
- price and availability of competitors’ supplies of oil, NGLs and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

The majority of our oil and NGL production and a portion of our gas production is currently sold to purchasers under short-term (less than 12-month) contracts at market based prices. The speed and severity of the decline in oil prices during 2015 and the continued lower prices in the first quarter of 2016 has adversely affected our cash flows, borrowing ability and the present value of our reserves. If oil, NGL and natural gas prices continue to deteriorate, we anticipate that the borrowing base under our Credit Facility, which is redetermined semi-annually, may be reduced. Lower oil, NGL and natural gas prices may also reduce the amount of oil, NGLs and natural gas that we can produce economically. Substantial and extended decreases in oil, NGL and natural gas prices could render uneconomic a significant portion of our identified drilling locations. This may result in our having to make further significant downward adjustments to our estimated proved reserves. As a result, this low commodity price environment and price volatility may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

We may be required to make deficiency payments under our Credit Facility because of a decrease in our borrowing base and may be unable to obtain funding in the capital markets on terms we find acceptable.

Historically, we have used our cash flows from operations and borrowings under our 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, 2015, we have a Credit Facility with a borrowing base of $252.0 million, $249.2 of which was available to use. In February 2016, the Company borrowed approximately $249.2 million under the Credit Facility, which represented the remaining undrawn amount that was available under the Credit Facility. The borrowing base under our 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. Should prices for oil, NGLs and natural gas remain weak or deteriorate, if we have a downward revision in estimates of our proved reserves, or if we sell oil, NGL 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 Credit Facility, which could result in an event of default.

In the future, we may not be able to access adequate funding under our 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 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. The cost of obtaining money from the credit markets has increased as lenders and institutional investors have increased interest rates, imposed tighter lending standards, refused to refinance existing debt at maturity on terms similar to existing debt or at all, or, in some instances, reduced or ceased 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 level of indebtedness may increase and reduce our financial flexibility.

At December 31, 2015, we have $293.6 million in 10.75% Senior Unsecured Notes Due 2020 (the “2020 Senior Notes”), $347.7 million in 9.25% Senior Unsecured Notes due 2021 (the “2021 Senior Notes” together with the 2020 Senior Notes, the “Unsecured Notes”), $625.0 million in Second Lien Senior Secured Notes due 2020 (the “Second Lien Notes”) and $529.7 million in Third Lien Senior Secured Notes due 2020 (the “Third Lien Notes” together with the Second Lien Notes and the Unsecured Notes, “the Senior Notes”) outstanding, which includes $5.5 million of paid in kind accrued interest. As of December 31, 2015, we had not drawn down on our Credit Facility. However, subsequent to year-end, we drew down the full capacity of the Credit Facility of $249.2 million, net of outstanding letters of credit.

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, NGL 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.

Our Credit Facility and the indentures governing our Senior Notes contain 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 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 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 Credit Facility could proceed against the collateral granted to them to secure that debt.

In addition, our Credit Facility requires us to maintain certain financial ratios. 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 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 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 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 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 Credit Facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. If liquidity concerns are not addressed in the near-term, we may breach the leverage covenant of our Credit Facility which currently requires a maximum ratio of total senior indebtedness to EBITDA of not more than 1.0:1.0. As of December 31, 2015, we were 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 covenants in our Credit Facility that is not waived by our lenders or otherwise cured could lead to a termination of our Credit Facility, acceleration of all amounts due under our 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.

The trading level of our debt is expressed as a percentage of the par value of the outstanding debt obligation, and our various outstanding debt obligations are currently trading at significant discounts to their par value. As of February 26, 2016, our 2020 Senior Notes were trading at 3.5% of par value, our 2021 Senior Notes were trading at 3.5% of par value, our Second Lien Notes were trading at 27.0% of par value and our Third Lien Notes were trading at 5.5% of par value. The trading level or market value of our debt is based upon many factors, including expectations regarding the likelihood of future repayment and the amount recoverable in the event of a default, our ability to pay interest and the risk tolerance of each debt holder. As of February 26, 2016, although the principal balance of our total debt, excluding outstanding borrowings under our Credit Facility, was approximately $1.8 billion, the fair market value of our debt, based upon quoted trading prices, was approximately $0.2 billion.

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. 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, 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;
- ability to economically dispose of produced saltwater;
- pressure or irregularities in geological formations;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems;
- limitations in the market for oil and natural gas; and
- 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, 2015.

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, 2015, 2014 and 2013, 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. 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 will be required to take further write-downs of the carrying values of our oil and natural gas properties.

We use the full cost method of accounting for our oil and gas properties. Accordingly, we capitalize and amortize all productive and nonproductive costs directly associated with property acquisition, exploration and development activities. Under the full cost method, the capitalized cost of oil and gas properties, less accumulated amortization and related deferred income taxes may not exceed the “cost center ceiling” which is equal to the sum of the present value of estimated future net revenues from proved reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, plus the costs of properties not subject to amortization, plus the lower of the cost or estimated fair value of unproved properties included in the costs being amortized, less related income tax effects. If the net capitalized costs exceed the cost center ceiling, we recognize the excess as an impairment of oil and gas properties. For the year ended December 31, 2015, we recognized an impairment charge of $1.6 billion 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 further declines in commodity prices.

Oil, NGL and natural gas prices are volatile. Our hedges expired in 2015. As we choose not to replace those hedges, our cash flows from operations will be subjected to increased volatility.

Historically, we have entered into hedging transactions of our oil, NGL and natural gas production to reduce our exposure to fluctuations in the price of oil, NGLs and natural gas. All of our existing hedges expired at December 31, 2015. As such, all of our current production will be sold at market prices, leaving us more exposed to the fluctuations in the price of oil, NGLs and natural gas and subjecting our cash flows from operations to increased volatility unless we enter into additional hedging transactions.

We have incurred losses from operations during certain periods historically and may continue to do so in the future.

We incurred losses from operations of $1.6 billion and $407.4 million for the years ended December 31, 2015 and 2013. 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 estimated 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 or Anadarko Basins 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 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.

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 may cause us to reclassify certain of our proved undeveloped reserves as unproved reserves, which may materially adversely affect our business, results of operations and financial condition. Specifically, due to uncertainty around our ability to adequately finance the development of our proved undeveloped reserves over a five year period, 77,362 MBoe comprising $179.0 million of PV-10 value (at SEC pricing) of proved undeveloped reserves has been transferred and booked in the probable reserve category as of December 31, 2015.

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, NGLs 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. It is extremely difficult to accurately predict with any level of certainty 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, infrastructure and/or downstream 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, 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 and Anadarko Basin 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 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 or its production, 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, water use 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. As further discussed in the risk factor below, 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.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of saltwater produced alongside our hydrocarbons, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business.

We dispose of large volumes of saltwater produced alongside oil and natural gas in connection with our drilling and production operations pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, the applicable legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements.

There exists a growing concern that the injection of saltwater into belowground disposal wells contribute to seismic activity in certain areas, including Oklahoma and Texas, where we operate. For instance, on April 21, 2015, the Oklahoma Geologic Survey (“OGS”) issued a document entitled “Statement of Oklahoma Seismicity,” in which the agency states “[t]he OGS considers it very likely that the majority of recent earthquakes, particularly those in central and north-central Oklahoma, are triggered by the injection of produced water in disposal wells.” In response to these concerns, regulators in some states , including Oklahoma and Texas, are pursuing initiatives designed to impose additional requirements in the permitting and operation of saltwater disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in 2014, the Oklahoma Corporation Commission adopted rules for operators of saltwater disposal wells in certain seismically-active areas, (“Areas of Interest”) in the Arbuckle formation, requiring operators to monitor and record well pressure and discharge volume on a daily basis and further requiring operators of wells permitted for disposal of 20,000 barrels per day or more of saltwater to conduct mechanical integrity testing. On March 25, 2015, the OGCD issued a directive, expanding the Areas of Interest for induced seismicity. Under the new directive, operators of 347 disposal wells located within the expanded Areas of Interest of the Arbuckle formation were given until April 18, 2015 to demonstrate that their wells were not disposing into or in communication with the crystalline basement rock underlying the Arkbuckle formation. Operators of wells in contact or communication with the basement rock were required to reduce the depth of, or “plug back,” those wells or, alternatively, to reduce disposal volume by 50 percent. On July 17, 2015, the OGCD issued another directive, further expanding the covered area to include an additional 211 disposal wells. Under this second directive, operators were given until August 14, 2015 to prove that they were not injecting below the Arbuckle formation or, as necessary, to plug back those wells in contact or communication with the crystalline basement rock, without the option of reducing disposal volume by 50 percent.

On November 19, 2015, the OGCD issued a directive to stop or reduce disposal volumes in the Cherokee-Carmen area, including 5 wells we currently operate. Most recently, on January 13, 2016, the OGCD announced a plan in response to recent earthquakes in the Fairview area of Oklahoma. The plan calls for changes to the operations of oil and gas wastewater disposal wells in the area that dispose into the Arbuckle formation. Under the plan, a total of 27 Arbuckle disposal wells will be required to reduce disposal volume. The plan will affect 7 disposal wells we currently operate in the Arbuckle formation. On February 16, 2016, the OGCD requested we curtail our wastewater disposal volumes by approximately 40%. We are currently in discussions with the OGCD regarding these matters and are working to mitigate any potential impact to our operations.

In Texas, effective on November 17, 2014, the Texas Railroad Commission adopted a new rule governing permitting or re-permitting of disposal wells that requires, 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 a permittee or a prospective permittee fails to demonstrate that the saltwater or other 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 Commission may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

The adoption and implementation of any new laws, regulations, or directives that restrict our ability to dispose of saltwater by plugging back the depths of disposal wells, reducing the volume of oil and natural gas wastewater disposed in such wells, restricting disposal well locations, or by requiring us to shut down disposal wells, which could require the Company to cease operations at a substantial number of its oil and natural gas wells, could have a material adverse effect on our ability to produce oil and gas economically and, accordingly, could materially and adversely affect our business, financial condition and results of operations.

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.

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 soil and 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 as a result of:

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

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

Increased costs of capital could adversely affect our business.

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

The inability of our significant purchasers 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 purchasers. Two purchasers accounted for 43% and 25%, respectively, of our revenues for the year ended December 31, 2015. We generally do not require our purchasers to post collateral. The inability or failure of any of our significant purchasers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition and results of operations.

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

We currently do not have any outstanding derivative instruments. However, to achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil, we have historically chosen to enter into derivative instruments at times for a portion of our oil, NGL and natural gas production. We do not designate 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 derivative instruments are recognized in current earnings. Accordingly, to the extent we enter into derivative instruments in the future, our earnings may fluctuate significantly as a result of changes in the fair value of any derivative instruments.

Derivative instruments would 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, any derivative arrangements in the future would likely limit the benefit we would receive from increases in the prices for oil, NGLs and natural gas.

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 and the Anadarko Basin in Texas and Oklahoma 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. We experienced significant management and board turnover in 2014, 2015 and early 2016. 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 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 2016 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 2016 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. It is unclear whether any of these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. 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 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, NGLs and natural 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 numerous stringent and complex federal, regional, state, local and other laws and regulations relating to pollution and protection of the environment, including those governing the release or disposal of materials into the environment. Potentially applicable environmental laws include, but are not limited to, (i) the CERCLA, and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or formerly owned or operated by us or locations to which we have sent wastes for disposal; (ii) the Clean Water Act ("CWA"), and analogous state laws, which regulate the discharge of waste and storm waters from some of our facilities; (iii) the CAA, and analogous state laws, which impose obligations related to air emissions, including emissions limits and permitting requirements; (iv) the RCRA, and analogous state laws, which impose requirements for the handling and disposal of solid or hazardous waste; (v) the Endangered Species Act, and analogous state laws, which seek to ensure that activities do not jeopardize endangered animal, fish and plant species; (vi) the National Environmental Policy Act, which requires federal agencies to study potential environmental impacts of a proposed federal action before it is approved; and (vii) OSHA, and analogous state laws, which establish certain employer responsibilities, including maintenance of a workplace free of recognized hazards. These laws and regulations may, among other things, require the acquisition of a permit before drilling commences, require the maintenance of bonding requirements in order to drill or operate wells, 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, impose specific standards for the plugging and abandoning of wells 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, operated 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 or remedial obligations 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 or complied with existing applicable laws 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 the 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, the EPA published a final rule on October 1, 2015 that reduces 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. Additionally, the EPA's 2014 - 2016 National Enforcement Initiatives include "Assuring Energy Extraction Activities Comply with Environmental Laws." According to the EPA's website, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." The EPA has emphasized that this initiative will be focused on those areas of the country where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us. 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; proposed in April 2015 effluent limit guidelines that saltwater from shale resource extraction operations must meet before discharging to publicly owned wastewater treatment plants (the final rule is expected to be issued in March 2016); 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 (the public comments period on the EPA's advance notice ended in September 2014, and a final notice of proposed rulemaking is expected in 2016) . Also, the BLM published a final rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands in March 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 which could spur initiatives to further regulate hydraulic fracturing under the SDWA or otherwise.

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 requires that we obtain and maintain numerous environmental, water access and land use permits and other approvals authorizing our regulated activities. We must renew these permits and approvals periodically, and the permits and approvals may be modified or revoked by the issuing agency. 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, water access or land use permits and other approvals, which we may not receive in a timely manner or at all.

The adoption of financial reform legislation by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. This legislation, known as the Dodd-Frank Act, was signed into law by President Obama on July 21, 2010 and requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. The financial reform legislation may also require compliance with margin requirements and with certain clearing and trade-execution requirements in connection with derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require certain counterparties to derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The final rules will be phased in over time according to a specified schedule which is dependent on the finalization of certain other rules to be promulgated jointly by the CFTC and the SEC. The Dodd-Frank Act and any new regulations could increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks, reduce our ability to monetize or restructure derivative contracts in the future and increase exposure to less creditworthy counterparties. In the future, if we are unable to use derivatives as a result of the legislation 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. Finally, the legislation was intended, in part, to reduce the volatility of oil, NGLs and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas liquids and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is even lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

Risks Relating to our Common Stock

If we file for bankruptcy, there is a high likelihood that the shares of our existing common stock would be cancelled.

We have a significant amount of indebtedness that is senior to our existing common stock in our capital structure. As a result, if we were to file for bankruptcy, we believe that it is highly likely that the shares of our existing common stock could be cancelled if any bankruptcy proceedings and would be entitled to a limited recovery, if any.

The NYSE has delisted our common stock, which could have a substantial effect on our liquidity and results of operations.

On February 3, 2016, the NYSE delisted our stock due to non-compliance with minimum listing standards. As a result, our common stock now trades in the OTC Pink market under the ticker symbol “MPOY.” Securities traded in the OTC Pink market generally have significantly less liquidity than securities traded on a national securities exchange, due to factors such as the reduced number of investors that will consider investing in the securities, the reduced number of market makers in the securities, and the reduced number of securities analysts that follow such securities. As a result, holders of shares of our common stock may find it difficult to resell their shares at prices quoted in the market or at all. Because of the limited market and generally low volume of trading in our common stock that could occur, the share price of our common stock could be more likely to be affected by broad market fluctuations, general market conditions, fluctuations in our operating results, changes in the market’s perception of our business, and announcements made by us, our competitors or parties with whom we have business relationships. The lack of liquidity in our common stock may also make it difficult for us to issue additional securities for financing or other purposes, or to otherwise arrange for any financing we may need in the future.

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 Credit Facility and the indentures governing our Senior Notes. Consequently, your only 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.

First Reserve holds a significant portion of our common stock. 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 25% of our shares of common stock and is controlled by First Reserve. Given their ownership level, First Reserve can have significant influence over our operations, can 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 may 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 (the “Stockholders’ Agreement”) that permits FRMI the right to nominate three members of our board of directors so long as FRMI holds at least 25% of our outstanding shares of common stock. Upon the identification by our board of directors of an additional director nominee that our board of directors has affirmatively determined is independent pursuant to the listing standards of the NYSE and Rule 10A-3 of the Exchange Act, FRMI has agreed to cause one of its director nominees to resign if so requested by the Board. At and as of such time that FRMI holds less than 25% of our outstanding shares of Common Stock, FRMI will have the right to nominate one member of our board of directors. The Stockholders’ Agreement also requires the stockholders party thereto to take all necessary actions, including voting their shares of common stock, for the election of the FRMI nominees and the board’s other nominees. In February 2016, FRMI’s director nominees resigned from our board of directors and we currently have no nominees from FRMI serving as directors.

As a result of FRMI’s equity, 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, 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.

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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of December 31, 2015, 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.

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.

During the periods covered in this document our common stock was listed on the New York Stock Exchange under the symbol "MPO." On February 3, 2016, we received notice from the NYSE that our common stock no longer met the NYSE continued listing requirements. As a result, our common stock was automatically delisted from the NYSE and, effective February 4, 2016, began trading on the OTC Pink marketplace under the symbol "MPOY". The following table sets forth the range of high and low sales prices of our common stock as reported by the NYSE (historical periods have been adjusted to be comparable with periods after our reverse stock split on August 3, 2015):

	Price Range	
	High	**Low**
2014		
First Quarter	$67.50	$41.30
Second Quarter	$75.00	$45.60
Third Quarter	$71.30	$50.50
Fourth Quarter	$52.60	$10.50
2015		
First Quarter	$16.40	$7.20
Second Quarter	$13.00	$8.50
Third Quarter	$7.70	$3.70
Fourth Quarter	$6.25	$1.95

Holders.

The number of shareholders of record of our common stock was approximately 21 on March 28, 2016.

Dividends.

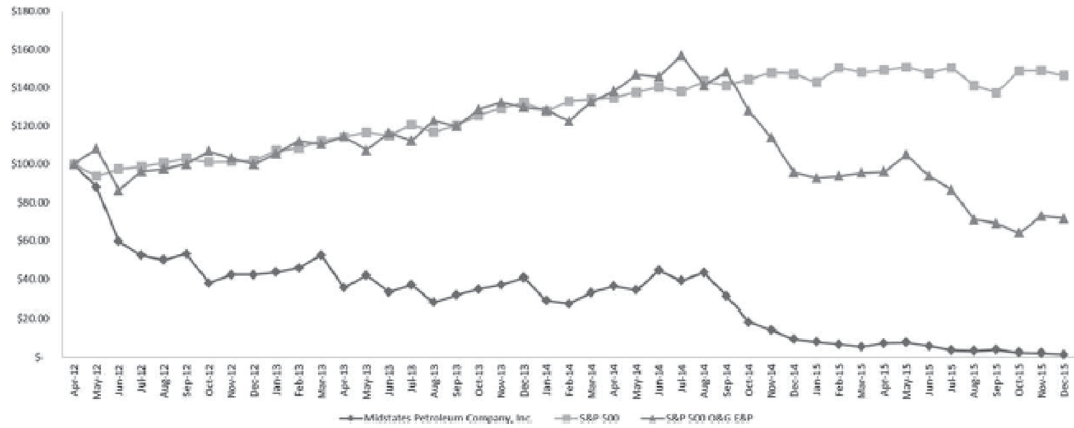
We have not paid any cash dividends since inception. In addition, our Credit Facility and the indentures governing our Senior Notes limit and restrict our ability to pay dividends on our capital stock. We currently intend to retain all future earnings for the development and growth of our business, and 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 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 common stock holders from the date our common stock began trading on the NYSE through December 31, 2015, as compared to the cumulative five-year total returns on the Standard and Poor's 500 Index ("S&P 500") 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 $130 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, 2015, which information has been derived from the Company's consolidated financial statements and the notes thereto included in Item 15 in this Annual Report on Form 10-K. This information should be read in conjunction with, and is qualified in its entirety by, the more detailed information in the Company's consolidated financial statements set forth in Item 15 of this Annual Report on Form 10-K.

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, 2015, 2014, and 2013 and the balance sheet data as of December 31, 2015, and 2014 are derived from our consolidated financial statements and the notes thereto included in Item 15 in this Annual Report on Form 10-K. The historical financial data for the years ended December 31, 2012 and 2011 and the balance sheet data as of December 31, 2013, 2012 and 2011 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,				
	2015(1)	**2014(2)**	**2013(3)**	**2012(4)**	**2011**
	(in thousands, except per share amounts)				
Income Statement Data					
Total revenues	$365,145	$794,183	$469,506	$247,673	$209,433
Net income (loss)	(1,797,195)	116,929	(343,985)	(150,097)	16,657
Net income (loss) attributable to common shareholders(5)	(1,798,143)	67,271	(359,574)	(156,597)	16,657
Net income (loss) per share attributable to common shareholders(6)					
Basic and diluted	$(232.74)	$10.13	$(54.68)	$(26.11)	N/A
Balance Sheet Data					
Cash and cash equivalents	$81,093	$11,557	$33,163	$18,878	$7,344
Net property and equipment	523,869	2,123,116	2,094,894	1,567,408	574,079
Total assets	679,167	2,447,175	2,308,637	1,665,927	624,656
Total debt, including debt classified as current(7)	1,890,944	1,706,532	1,667,680	675,917	234,800
Stockholders'/members' equity (deficit)	(1,326,066)	465,862	339,999	677,469	285,502
Weighted average number of common shares outstanding	7,726	6,644	6,576	5,997	N/A
Other Financial Data					
Net cash provided by operating activities	$213,383	$351,544	$237,588	$145,019	$141,550
Net cash used in investing activities	(294,556)	(404,264)	(1,204,332)	(781,378)	(242,619)
Net cash provided by financing activities	150,709	31,114	981,029	647,893	96,496
Adjusted EBITDA(8)	315,340	474,098	330,759	144,619	152,616

(1) The year ended December 31, 2015 reflects the Dequincy Divestiture, which closed on April 21, 2015. 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, 2014 reflects the Pine Prairie Disposition, 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.

(3) The year ended December 31, 2013 reflects the Anadarko Basin Acquisition, which closed on May 31, 2013. 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 year ended December 31, 2012 reflects the Eagle Property Acquisition, which closed on October 1, 2012.

(5) The years ended December 31, 2015, 2014, 2013 and 2012 include the effect of an undeclared Series A Preferred Stock dividend of $0.9 million, $10.4 million, $15.6 million and $6.5 million, respectively, which was paid in shares upon the mandatory conversion of the Preferred Stock into common shares on September 30, 2015. 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.

(6) 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).

(7) The Company is in default under its Credit Facility, the failure of which to cure could result in the acceleration of the Company's debt. As a result, the Company's debt was classified as current as of December 31, 2015. See "—Note 9. Debt" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

(8) 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 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,				
	2015	2014	2013	2012	2011
	(in thousands)				
Adjusted EBITDA reconciliation to net income (loss):					
Net income (loss)	$(1,797,195)	$116,929	$(343,985)	$(150,097)	$16,657
Depreciation, depletion and amortization	198,643	269,935	250,396	125,561	91,699
Impairment in carrying value of oil and gas properties	1,625,776	86,471	453,310	—	—
Loss on sale/impairment of field equipment inventory	1,997	4,056	615	—	—
(Gains) Losses on commodity derivative contracts—net	(40,960)	(139,189)	44,284	11,158	4,844
Net cash received (paid) for commodity derivative contracts not designated as hedging instruments	167,669	(18,332)	(17,585)	(15,825)	(16,733)
Income tax expense (benefit)	(9,641)	6,395	(146,529)	157,886	—
Interest income	(115)	(39)	(33)	(245)	(23)
Interest expense, net of amounts capitalized	163,148	137,548	83,138	12,999	2,094
Asset retirement obligation accretion	1,610	1,706	1,435	723	334
Share-based compensation, net of amounts capitalized	4,408	8,618	5,713	2,459	53,744
Adjusted EBITDA	**$315,340**	**$474,098**	**$330,759**	**$144,619**	**$152,616**

	As of and For the Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands)				
Adjusted EBITDA reconciliation to net cash provided by operating activities:					
Net cash provided by operating activities	$213,383	$351,544	$237,588	$145,019	$141,550
Changes in working capital(1)	(58,293)	(7,098)	16,021	(11,624)	9,845
Interest income	(115)	(39)	(33)	(245)	(23)
Interest expense, net of amounts capitalized and accrued but not paid(2)	171,681	137,548	83,138	12,999	2,094
Amortization of deferred financing costs	(11,316)	(7,857)	(5,955)	(1,530)	(850)
Adjusted EBITDA	**$315,340**	**$474,098**	**$330,759**	**$144,619**	**$152,616**
Acquisition and transaction costs	330	4,129	11,803	14,884	—
Debt restructuring costs and advisory fees	36,141	—	—	—	—
Adjusted EBITDA before transaction, restructuring and advisory costs	**$351,811**	**$478,227**	**$342,562**	**$159,503**	**$152,616**

(1) Changes in working capital for all periods have been adjusted for the loss on sale/impairment of field equipment inventory and current taxes. Additionally, the 2015 change in working capital includes $34.4 million of restructuring transaction costs that were paid during the year.

(2) Interest expense for the year ended December 31, 2015 excludes $6.4 million in accrued paid in kind interest on the Third Lien Notes and $14.9 million in amortization of deferred gain on troubled debt restructuring. See "—Note 9. Debt" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

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 and Anadarko Basin.

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.

In October 2012, the Company closed on the acquisition of all of Eagle Energy Production, LLC's producing properties and undeveloped acreage, located primarily in the Mississippian Lime liquids play in Oklahoma. In May 2013, the Company completed an acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company. In May 2014, the Company closed on the divestiture of all of its ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana. Then, in April 2015, the Company completed the divestiture of its remaining producing properties in Louisiana with the Dequincy Divestiture. As of December 31, 2015, the Company has no proved reserves or production in the Gulf Coast operating area.

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, 2015, since the third quarter of 2008 we had spud approximately 461 gross wells (including 248 in our Mississippian operating area since the fourth quarter of 2012 and 69 in our Anadarko operating area since the second quarter of 2013).

As of December 31, 2015, our properties consisted of approximately 204,791 net acre leasehold, with 749 gross active producing wells, 65% of which we operate, and in which we held an average working interest of approximately 69%. As of December 31, 2015, our estimated net proved reserves were 73.5 MMBoe, of which 56% was oil or NGLs and 94% was proved developed. During the three months and year ended December 31, 2015, our properties had aggregate average net daily production of approximately 30,890 Boe/d and 32,880 Boe/d, respectively.

Recent Developments

Debt Restructuring and Credit Facility. On May 21, 2015, we completed a debt restructuring transaction which included the issuance of $625.0 million of 10.0% Senior Secured Second Lien Notes due 2020 and utilized the proceeds to repay the outstanding balance of our Credit Facility in an amount of approximately $468.2 million, with the remainder available for general corporate purposes. Further, we exchanged approximately $504.1 million of 12.0% Third Lien Senior Secured Notes due 2020 for approximately $279.8 million of 10.75% Senior Notes due 2020 and $350.3 million of 9.25% Senior Notes due 2021, representing an exchange at 80.0% of the exchanged Unsecured Notes' par value. Additionally, on June 2, 2015, we exchanged approximately $20.0 million of Third Lien Notes for approximately $26.6 million of 2020 Senior Notes and $2.0 million of 2021 Senior Notes, representing an exchange at 70.0% of the exchanged Unsecured Notes' par value. Approximately $63.9 million of the principal amount of 2020 Senior Notes and $70.7 million of the principal amount of 2021 Senior Notes were extinguished as a result of the exchanges occurring at a percentage below the Unsecured Notes' par value.

Additionally, we entered into the Seventh Amendment to the Credit Facility (the "Seventh Amendment") which provided that upon completion of the offering of the Second Lien Notes and Third Lien Notes, the borrowing base of the Credit Facility would be reduced to $252.0 million. The Seventh Amendment also provided additional covenant flexibility. Further discussion regarding the Second Lien Notes, Third Lien Notes and Seventh Amendment can be found below under "—Liquidity and Ability to Continue as a Going Concern."

On October 14, 2015, we entered into the Ninth Amendment to the Credit Facility which, among other things, reaffirmed the borrowing base at $252.0 million and provided flexibility for certain specified asset sales by confirming the amount of the reduction in the borrowing base if any such sale should occur.

Reverse Stock Split. On August 3, 2015, we completed a 1-for-10 reverse stock split of our outstanding common stock. To effect the reverse stock split, we filed a Certificate of Amendment to our Restated Certificate of Incorporation, which provides for the reverse stock split and for the corresponding reduction in our authorized capital stock to 100 million shares of common stock, $0.01 par value per share, following the reverse stock split.

Series A Preferred Stock. On October 1, 2012, we issued 325,000 shares of Series A Mandatorily Convertible Preferred Stock ("Series A Preferred Stock") with an initial liquidation preference of $1,000 per share and an 8.0% per annum dividend, payable semiannually at the Company's option in cash or through an increase in the liquidation preference. On September 30, 2015, all 325,000 shares of the Series A Preferred Stock converted into shares of our common stock at a conversion price of $110.00 per share, which was automatically adjusted to reflect the reverse stock split. Each Series A Preferred Share converted into approximately 11.5 shares of our common stock, and as a result, we issued 3,738,424 additional shares of our common stock upon conversion of the Series A Preferred Stock.

Delistment. On February 3, 2016, we received notice from the NYSE that the Company's common stock no longer met the NYSE continued listing requirements. As a result, the Company's common stock was automatically delisted from the NYSE and began trading on the OTC Pink marketplace, an over the counter exchange, under the symbol "MPOY".

Ability to Continue as a Going Concern

As a result of the sustained commodity price decline and our substantial debt burden, we believe that forecasted cash and available credit capacity will not be sufficient to meet commitments as they come due over the next twelve months, and we will not be able to remain in compliance with current debt covenants unless we are able to successfully increase liquidity or deleverage. The uncertainty associated with the ability to meet commitments as they come due or to repay outstanding debt raises substantial doubt about our ability to continue as a going concern. In consideration of the uncertainty mentioned above, the report of our independent registered public accounting firm that accompanies our audited consolidated financial statements for the year ended December 31, 2015 in this Annual Report on Form 10-K contains an explanatory paragraph regarding an event of default under the Credit Facility, a projected additional debt covenant violation, and resulting lack of liquidity, which raises substantial doubt about our ability to continue as a going concern.

The report of our independent registered public accounting firm that accompanied our consolidated financial statements for the year ended December 31, 2014 also contained an explanatory paragraph regarding a projected debt covenant violation and resulting lack of liquidity raising substantial doubt about our ability to continue as a going concern; however, we obtained a waiver to the Credit Facility waiving any default as a result of receiving such explanatory paragraph in 2014. We have not received a similar waiver from our lenders under the Credit Facility for the explanatory paragraph to our 2015 independent registered public accounting firm report. As a result, we are in default under our Credit Facility. A failure to cure this default within 30 days will result in the acceleration of all of our indebtedness under the Credit Facility. If the lenders under our Credit Facility accelerate the loans outstanding thereunder, we will also be in default under the indentures governing our Senior Notes, in which case the lenders under the indentures governing our Senior Notes could accelerate the repayment thereof.

If lenders, and subsequently noteholders, accelerate the Company's outstanding indebtedness, it will become immediately due and payable and the Company will not have sufficient liquidity to repay those amounts. If we are unable to reach an agreement with our creditors prior to any of the above described accelerations, we could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

Risks and Uncertainties

Our decisions on capital structure, hedging and drilling are based upon widely available information of anticipated future commodity pricing and expected economic conditions. The unexpected substantial decrease in oil and gas prices that began in the second half of 2014 and continued throughout 2015 and into 2016 has resulted in materially lower operating cash flows than expected. Our hedging contracts helped to mitigate the impact of lower commodity prices during 2015 and we received cash settlements of these derivatives of $167.7 million, which comprised 78.6% of our cash provided by operations during 2015. However, all of our hedging contracts expired during 2015, and as a result, we will not receive any cash derivative settlements for 2016 or future periods as compared to our historical operating cash flows.

In February 2016, we borrowed approximately $249.2 million under our Credit Facility, which represented the remaining undrawn amount that was available under the Credit Facility and as a result, as of February 9, 2016, we had a cash balance of approximately $335.7 million. Our borrowing base under our Credit Facility will be redetermined in April 2016. Any reduction in the borrowing base of the Credit Facility will result in a deficiency which must be repaid 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 the Credit Facility.

We have substantial interest payment obligations over the next twelve months related to our debt. As of December 31, 2015, payments due on contractual obligations during the next twelve months were approximately $188.0 million. This includes approximately $179.5 million of interest payments on our Senior Notes and other operating expenses such as fixed drilling commitments and operating leases. The Company's next scheduled interest payment is April 1, 2016 for $15.8 million to the holders of the 2020 Senior Notes and the Company is currently evaluating whether such interest payment will be made. If the payment is not made by April 1, 2016, we would have 30 days to cure such payment default before an event of default occurs.

As a result of the sustained commodity price decline and our substantial debt burden, we believe that forecasted cash and available credit capacity will not be sufficient to meet our commitments as they come due over the next twelve months, and we will not be able to remain in compliance with current debt covenants unless we are able to successfully increase liquidity or deleverage. The uncertainty associated with the ability to meet commitments as they come due or to repay 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 the ability to meet obligations as they come due.

In order to increase our liquidity to levels sufficient to meet our commitments, we are currently undertaking a number of actions, including minimizing capital expenditures, aggressively managing working capital and further reducing our recurring operating expenses. We believe that even after taking these actions, we will not have sufficient liquidity to satisfy our debt service obligations, meet other financial obligations, and comply with our debt covenants. We have engaged financial and legal advisors to assist with analyzing various strategic alternatives to address our liquidity and capital structure, among other things. We believe a filing under Chapter 11 of the U.S. Bankruptcy Code may provide the most expeditious manner in which to effect a capital structure solution. There can be no assurance we will be able to restructure our capital structure on terms acceptable to us, our creditors, or at all.

Our Revenue

Oil, NGLs and natural gas. 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 continued decline in commodity prices could materially and adversely affect our business, financial condition and results of operations. Prices for oil, NGLs and natural gas fluctuate widely and affect:

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

Average market prices for oil and NGLs decreased significantly in the last part of 2014 with continued declines through 2015. If commodity prices remain depressed as compared to historical levels, we expect significantly lower revenues and operating cash flows compared to historical results. 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."

Realized and unrealized gain (loss) on commodity derivative financial contracts. We, at times, utilize commodity derivatives to reduce our exposure to fluctuations in the prices of oil, NGLs and natural gas. 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. We had no open derivative contracts at December 31, 2015 and currently have no open derivative contracts.

Our Expenses

Lease operating and workover expenses. Lease operating expenses represent 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 2015 and 2014, these costs primarily relate to the amended gas transportation, gathering and processing contract which commenced during the third quarter of 2013 in our Mississippian Lime area of operations.

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 which remain to be evaluated, 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.

Impairment in carrying value of oil and gas properties. 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, reporting expenses, investor relations, director and officer liability insurance costs, and director compensation.

Acquisition and transaction costs. The Anadarko Basin Acquisition qualified as the acquisition of a business under Accounting Standards Codification ("ASC") Topic 805, *Business Combinations*. Acquisition and transaction costs are costs we have has incurred as a result of acquisitions or as a result of asset disposal transactions such as the Pine Prairie Disposition and Dequincy Divestiture, 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.

Debt restructuring costs. In the second quarter of 2015, we completed a series of transactions to restructure a portion of our long-term debt. We incurred various costs related to these transactions, including advisory fees, legal fees and financing expenses, which are separately identified in the statement of operations for the year ended December 31, 2015.

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 have substantial long-term debt in the form of our Senior Notes. Additionally, we finance a portion of our working capital requirements and capital expenditures with borrowings under our 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 Credit Facility in interest expense, as well as the amortization of the related deferred financing costs, net of any amounts capitalized to unproved properties. Amortization of the deferred gain recognized on the restructuring of our debt, which occurred in the second quarter of 2015, is recognized using the effective interest method as a reduction to interest expense.

Results of Operations

The following tables summarize our revenues, production and price data for the periods indicated. Periods prior to April 21, 2015 include production, revenue and lease operating expenses related to the Dequincy properties, the sale of which closed on April 21, 2015. Prior to May 1, 2014, our operating results include production, revenue and lease operating expenses attributable to the Pine Prairie field assets, 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. Additionally, the 2013 period includes only seven months of results from our Anadarko Basin area due to the timing of the Anadarko Basin Acquisition.

Revenues

	Years Ended December 31,					
	2015		2014		2013	
	(in thousands)					
REVENUES:						
Oil sales	$217,636	67%	$466,655	71%	$387,226	76%
Natural gas liquid sales	38,249	12%	87,771	13%	62,340	12%
Natural gas sales	66,823	21%	99,204	16%	63,187	12%
Total oil, natural gas, and natural gas liquids sales	**322,708**	**100%**	**653,630**	**100%**	**512,753**	**100%**
Realized gains (losses) on commodity derivative contracts, net	167,669	409%	(18,332)	(13)%	(17,585)	40%
Unrealized gains (losses) on commodity derivative contracts, net	(126,709)	(309)%	157,521	113%	(26,699)	60%
Gains (losses) on commodity derivative contracts—net	**40,960**	**100%**	**139,189**	**100%**	**(44,284)**	**100%**
Other	1,477		1,364		1,037	
Total revenues	**$365,145**		**$794,183**		**$469,506**	

Production

	Years Ended December 31,				
	2015	% Change	2014	% Change	2013
PRODUCTION DATA:					
Oil (MBbls)	4,794	(7)%	5,144	32%	3,904
Natural gas liquids (MBbls)	2,473	2%	2,417	41%	1,719
Natural gas (MMcf)	28,403	14%	25,013	34%	18,657
Oil equivalents (MBoe)	12,001	2%	11,730	34%	8,733
Oil (Boe/day)	13,134	(7)%	14,094	32%	10,697
Natural gas liquids (Boe/day)	6,776	2%	6,622	41%	4,711
Natural gas (Mcf/day)	77,817	14%	68,528	34%	51,116
Average daily production (Boe/d)	32,880	2%	32,137	34%	23,927

Prices

	Years Ended December 31,				
	2015	% Change	2014	% Change	2013
AVERAGE SALES PRICES:					
Oil, without realized derivatives (per Bbl)	$45.40	(50)%	$90.71	(9)%	$99.18
Oil, with realized derivatives (per Bbl)	$74.74	(15)%	$87.40	(6)%	$93.41
Natural gas liquids, without realized derivatives (per Bbl)	$15.46	(57)%	$36.31	—%	$36.26
Natural gas liquids, with realized derivatives (per Bbl)	$15.46	(58)%	$36.40	(2)%	$37.09
Natural gas, without realized derivatives (per Mcf)	$2.35	(41)%	$3.97	17%	$3.39
Natural gas, with realized derivatives (per Mcf)	$3.30	(16)%	$3.91	9%	$3.58

Oil, Natural Gas Liquids and Natural Gas Revenues.

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Our oil sales revenues decreased by $249.1 million, or 53%, to $217.6 million during the year ended December 31, 2015 as compared to $466.7 million for the year ended December 31, 2014. Lower revenue was primarily the result of decreases in oil prices for the year ended December 31, 2015 as compared to the year ended December 31, 2014. Oil volumes sold decreased 350 MBbls or 7% to 4,794 MBbls for the year ended December 31, 2015 from 5,144 MBbls for the year ended December 31, 2014. The decrease in oil volumes sold was due to a decrease of 84%, or 514 MBbls, of production volumes in the Gulf Coast due to the sale of our remaining producing properties in Louisiana in April of 2015, as well as a decrease of 33%, or 487 MBbls in production volumes from our Anadarko Basin area attributable to natural production declines as we ran no drilling rigs during the year ended December 31, 2015 due to the decline in commodity prices. These decreases were partially offset by an increase in Mississippian Lime production of 21%, or 651 MBbls. For the year ended December 31, 2015, we brought approximately 81 wells online in the Mississippian Lime, which drove the 21% increase in daily production in the Mississippi Lime area. Average oil sales prices, without realized derivatives, decreased by $45.31 per barrel, or 50%, to $45.40 per barrel for the year ended December 31, 2015 as compared to $90.71 for the year ended December 31, 2014. Of the $217.6 million in total oil sales revenues, $169.2 million was from Mississippian Lime operations, $43.7 million was from the Anadarko Basin and $4.7 million was from the Gulf Coast.

Our NGLs sales revenues decreased by $49.6 million, or 56%, to $38.2 million during the year ended December 31, 2015 as compared to $87.8 million for the year ended December 31, 2014. Lower revenue was primarily the result of decreases in NGLs prices for the year ended December 31, 2015 as compared to the year ended December 31, 2014. NGLs volumes sold increased 56 MBbls, or 2%, to 2,473 MBbls for the year ended December 31, 2015 as compared to 2,417 MBbls for the year ended December 31, 2014. The increase in NGLs volumes sold was attributable to an increase of 317 MBbls of production volumes from our Mississippian Lime area, partially offset by decreases in Anadarko Basin production of 138 MBbls and Gulf Coast production of 123 MBbls. Average NGLs prices, without realized derivatives, decreased by $20.85 per barrel, or 57%, to $15.46 per barrel for the year ended December 31, 2015 as compared to $36.31 per barrel for the year ended December 31, 2014. Of the $38.2 million in total NGLs revenues, $30.7 million was from Mississippian Lime operations, $7.0 million was from the Anadarko Basin and $0.5 million was from the Gulf Coast.

Our natural gas sales revenues decreased by $32.4 million, or 33%, to $66.8 million during the year ended December 31, 2015 as compared to $99.2 million for the year ended December 31, 2014. Lower revenue was primarily the result of decreases in natural gas prices for the year ended December 31, 2015 as compared to the year ended December 31, 2014. Natural gas volumes sold increased 3,390 MMcf, or 14%, to 28,403 MMcf for the year ended December 31, 2015 as compared to 25,013 MMcf for the year ended December 31, 2014. The increase in natural gas volumes sold was attributable to an increase of 4,622 MMcf of production volumes from our Mississippian Lime area, partially offset by decreases of 733 MMcf in production from our Anadarko Basin area and 499 MMcf from our Gulf Coast area. Average natural gas prices, without realized derivatives, decreased by $1.62 per Mcf, or 41%, to $2.35 per Mcf for the year ended December 31, 2015 as compared to $3.97 per Mcf for the year ended December 31, 2014. Of the $66.8 million in total natural gas sales revenues, $56.5 million was from Mississippian Lime operations, $10.1 million was from Anadarko Basin and $0.2 million was from the Gulf Coast.

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 Disposition). For the twelve months ended December 31, 2014, we brought approximately gross 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 Disposition). 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 Disposition). 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.

Gains/Losses on Commodity Derivative Contracts—Net.

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Our overall derivative gain of $41.0 million for the year ended December 31, 2015 was attributable to realized gains of $167.7 million, offset by $126.7 million related to mark-to-market ("MTM") derivative positions as of December 31, 2014.

The realized gain on derivatives for the year ended December 31, 2015 was $167.7 million compared to a realized loss of $18.3 million for the year ended December 31, 2014. See the following table:

	Year Ended December 31, 2015	
	Realized Gain	Average Sales Price
	(in thousands)	
Oil commodity contracts	$140,656	$74.74
Natural gas liquids commodity contracts	—	—
Natural gas commodity contracts	27,013	3.30
Realized gain on commodity derivative contracts, net	**$167,669**	

Cash settlements, as presented in the table above, represent realized gains related to our derivative instruments. In addition to cash settlements, we also recognize fair value changes on our derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves. We currently have no derivative instruments and had none outstanding at December 31, 2015.

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

Our overall derivative gain of $139.2 million for the year ended December 31, 2014 was attributable to unrealized gains of $157.5 million related to MTM derivative positions, offset by $18.3 million in realized losses.

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)	$87.40
Natural gas liquids commodity contracts	217	36.40
Natural gas commodity contracts	(1,489)	3.91
Realized loss on commodity derivative contracts, net	**$(18,332)**	

Cash settlements, as presented in the table above, represent realized gains related to our derivative instruments. In addition to cash settlements, we also recognize fair value changes on our derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves.

Expenses

	Years Ended December 31,			Years Ended December 31,		
	2015	2014	2013	2015	2014	2013
	(in thousands)			(per Boe)		
EXPENSES:						
Lease operating and workover	$81,473	$79,598	$73,414	$6.79	$6.79	$8.41
Gathering and transportation	15,546	13,404	5,455	$1.30	$1.14	$0.62
Severance and other taxes	8,605	24,266	27,237	$0.72	$2.07	$3.12
Asset retirement accretion	1,610	1,706	1,435	$0.13	$0.15	$0.17
Depreciation, depletion, and amortization	198,643	269,935	250,396	$16.55	$23.01	$28.67
Impairment of oil and gas properties	1,625,776	86,471	453,310	$135.47	$7.37	$51.91
General and administrative	38,703	48,733	53,250	$3.22	$4.15	$6.10
Acquisition and transaction costs	330	4,129	11,803	$0.03	$0.35	$1.35
Debt restructuring costs and advisory fees	36,141	—	—	$3.01	$—	$—
Other	2,121	5,108	615	$0.18	$0.44	$0.07
Total expenses	**$2,008,948**	**$533,350**	**$876,915**	**$167.40**	**$45.47**	**$100.42**

Lease Operating and Workover.

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Lease operating and workover expenses increased $1.9 million, or 2%, to $81.5 million for the year ended December 31, 2015 compared to $79.6 million for the year ended December 31, 2014. Lease operating expenses decreased $4.4 million, or 6%, to $70.1 million for the year ended December 31, 2015 as compared to $74.5 million for the year ended December 31, 2014. The decrease in lease operating expense is primarily related to the Dequincy Divestiture in the second quarter of 2015. Workover expenses increased $6.3 million, or 124%, to $11.4 million for the year ended December 31, 2015, as compared to $5.1 million for the year ended December 31, 2014. The increase in workover expenses during the year is due to increased production optimization projects, primarily in the Anadarko Basin. While the total lease operating and workover expenses increased, the per unit amounts remained unchanged at $6.79 per Boe for both years ended December 31, 2015 and 2014.

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.

Gathering and Transportation.

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Gathering and transportation expense increased $2.1 million, or 16%, to $15.5 million for the year ended December 31, 2015 compared to $13.4 million for the year ended December 31, 2014. The increase was primarily attributable to the 14% increase in natural gas production volumes for the year ended December 31, 2015, which are subject to gathering and transportation fees, including our gas transportation, gathering and processing contract in the Mississippian Lime.

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

Gathering and transportation expense 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 a gas transportation, gathering and processing contract which commenced during the third quarter of 2013 in the Mississippian Lime. As such, the year ended December 31, 2013 includes only two quarters of the expense.

Severance and Other Taxes.

	Years Ended December 31,		
	2015	**2014**	**2013**
		(in thousands)	
Total oil, natural gas, and natural gas liquids sales	**$322,708**	**$653,630**	**$512,753**
Severance taxes	5,754	17,723	21,338
Ad valorem and other taxes	2,851	6,543	5,899
Severance and other taxes	**$8,605**	**$24,266**	**$27,237**
Severance taxes as a percentage of sales	**1.8%**	**2.7%**	**4.2%**
Severance and other taxes as a percentage of sales	**2.7%**	**3.7%**	**5.3%**

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Severance and other taxes decreased $15.7 million, or 65%, to $8.6 million for the year ended December 31, 2015 as compared to $24.3 million for the year ended December 31, 2014. Severance taxes decreased $11.9 million, or 67%, to $5.8 million for the year ended December 31, 2015 compared to $17.7 million for the year ended December 31, 2014 and as a percentage of sales, decreased from 2.7% for the year ended December 31, 2014 to 1.8% for the corresponding 2015 period. The decrease was primarily due to lower realized pricing in the 2015 period and the sale of our Louisiana properties which had higher effective severance tax rates than our Mississippian Lime and Anadarko Basin properties. Ad valorem taxes decreased $3.7 million, or 56%, to $2.9 million for the year ended December 31, 2015, as compared to $6.6 million for the year ended December 31, 2014, due to a significant decrease in the value of our proved oil and gas reserves.

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, decreased from 4.2% for the year ended December 31, 2013 to 2.7% for the corresponding 2014 period. The decrease was primarily 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, due to higher ad valorem taxes in the Anadarko Basin and Gulf Coast area.

Depreciation, Depletion and Amortization (“DD&A”).

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

DD&A expense decreased $71.3 million, or 26%, to $198.6 million for the year ended December 31, 2015 compared to $269.9 million for the year ended December 31, 2014. The decreased DD&A expense is primarily attributable to lower DD&A rates, $16.55 per Boe for the year ended December 31, 2015 as compared to $23.01 per Boe for the year ended December 31, 2014, primarily due to ceiling test impairments recognized during the 2015 period.

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.

Impairment of Oil and Gas Properties.

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Our impairment of oil and gas properties pursuant to the full cost ceiling test was $1.6 billion and $86.5 million for the years ended December 31, 2015 and 2014, respectively. Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of capitalized costs associated with our oil and natural gas properties in our consolidated balance sheets. The impairment expense for the 2015 period was primarily due to a decrease in the PV-10 value of our proven oil and natural gas reserves as a result of continued low commodity prices. Subsequent to December 31, 2015, commodity prices have declined further. As a result, the simple average of oil and natural gas prices as of the first day of each month for the trailing 12-months utilized in calculating the PV-10 value of our oil and gas properties will continue to decline throughout the first quarter of 2016, which will negatively impact the discounted present value of the Company’s proved oil and gas reserves and could lead to additional impairments.

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.

General and Administrative (“G&A”).

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Our G&A expenses decreased to $38.7 million for the year ended December 31, 2015 from $48.7 million for the year ended December 31, 2014. The $10.0 million decrease period over period is primarily related to a $4.8 million reduction in employee costs due to reduced headcount in 2015, a $4.4 million increase in capitalized overhead costs and cost recoveries, as well as $0.6 million less in professional fees.

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.

Acquisition and Transaction Costs.

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Our acquisition and transaction costs decreased by $3.8 million to $0.3 million for the year ended December 31, 2015 from $4.1 million for the year ended December 31, 2014. For the twelve months ending December 31, 2015, these costs are related to our expenses incurred with the Dequincy Divestiture discussed above. For the comparable period in 2014, these costs generally represent our expenses related to the Pine Prairie Disposition discussed above.

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.

Debt Restructuring Costs and Advisory Fees.

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

During the 2015 period, we engaged various advisors to assist us in analyzing options to improve our financial flexibility and provide additional long-term liquidity. For the year ended December 31, 2015, we incurred approximately $36.1 million in fees associated with these advisors as well as issuance costs associated with the Second Lien Notes offering and Third Lien Notes exchange. No such costs were incurred in the comparable 2014 and 2013 periods.

Other.

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Other operating expenses for the year ended December 31, 2015 were $2.1 million, compared to $5.1 million for the year ended December 31, 2014. During the year ended December 31, 2015, these expenses relate to the loss on disposal of, or market value adjustments to, field equipment inventory deemed no longer useful to current operations. The comparable period in 2014 included these inventory adjustments, as well as penalty fees associated with the early termination of a drilling contract and other miscellaneous expenses.

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.

Other Income/Expense

	Years Ended December 31,		
	2015	2014	2013
		(in thousands)	
OTHER INCOME (EXPENSE)			
Interest income	$115	$39	$33
Interest expense	(182,955)	(149,962)	(115,383)
Amortization of deferred gain	14,948	—	—
Capitalized interest	4,859	12,414	32,245
Interest expense—net of amounts capitalized	(163,148)	(137,548)	(83,138)
Total other income (expense)	**$(163,033)**	**$(137,509)**	**$(83,105)**

Interest Expense

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Interest expense, before capitalized interest, for the years ended December 31, 2015 and 2014 was $168.0 million and $150.0 million, respectively. The increase in interest expense was primarily due to the issuance of the Second Lien Notes on May 21, 2015 and Third Lien Notes on May 21, 2015 and June 2, 2015. The Second Lien Notes bear interest at 10.0% and a portion of the proceeds were used to repay outstanding borrowings under the Credit Facility. Additionally, the Third Lien Notes bear interest at 12.0% and were exchanged for a portion of the 2020 Senior Notes and 2021 Senior Notes, which had stated interest rates of 10.75% and 9.25%, respectively. Further, approximately $4.6 million in unamortized debt costs were impaired during the 2015 period as a result of the Seventh Amendment to the Credit Facility. Increased interest expense was partially offset by $14.9 million in amortization of the deferred gain on forgiven debt related to the Third Lien Notes exchange. For the years ended December 31, 2015 and 2014, approximately $4.9 million and $12.4 million, respectively, in interest expense was capitalized to oil and gas properties. Capitalized interest was lower due to a decrease in the balance of our unevaluated property during the 2015 period. The remaining value of unevaluated properties was transferred to the full cost pool as of December 31, 2015.

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 full year of interest associated with the 2021 Senior Notes issued in 2013. Our average outstanding balance under our 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.

Provision for Income Taxes.

Year Ended December 31, 2015 as Compared to the Year Ended December 31, 2014

Our income tax benefit was $9.6 million for the year ended December 31, 2015 and represents an application of our estimated effective tax rate (including state income taxes) for the year ended December 31, 2015 of approximately 0.5% to the pre-tax loss incurred throughout the year. The significant reason for the change from an income tax expense to a benefit during the year ended December 31, 2015 was the change in unrealized derivative losses of $126.7 million.

In light of the impairment of oil and gas properties, we have recorded a $689.4 million valuation allowance during the year against our federal and state net operating losses (“NOL”), 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 carrying value of properties over their respective tax bases. No other sources of future taxable income were considered in this judgment.

In November 2015, the Financial Accounting Standards Board (the “FASB”) issued Accounting Standards Update (“ASU”) 2015-17, “Balance Sheet Classification of Deferred Taxes,” (“ASU 2015-17”) which requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent in the balance sheet. As a result, we will now only present our deferred income taxes on a net noncurrent basis. Companies are still prohibited from offsetting deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. We have early adopted this standard and have applied the change in accounting as of December 31, 2015 on a prospective basis. Adoption of this amendment did not have an effect on our financial position or results of operations, and prior periods were not retrospectively adjusted.

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 pre-tax income incurred throughout the year. The significant reason 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.

Liquidity and Ability to Continue as a Going Concern

Our decisions on capital structure, hedging and drilling are based upon widely available information of anticipated future commodity pricing and expected economic conditions. The unexpected substantial decrease in oil and gas prices that began in the second half of 2014 and continued throughout 2015 and into 2016 has resulted in materially lower operating cash flows than expected. Our hedging contracts helped to mitigate the impact of lower commodity prices during 2015 and we received cash settlements of these derivatives of $167.7 million, which comprised 78.6% of our cash provided by operations during 2015. However, all of our hedging contracts expired during 2015, and as a result, we will not receive any cash derivative settlements for 2016 or future periods, which will materially lower cash provided by operations in those future periods as compared to our historical operating cash flows.

As a result of the commodity price decline and our substantial debt burden, we took steps to increase our liquidity and amended certain debt covenants during 2015. On April 21, 2015, we closed on the Dequincy Divestiture for approximately $44.0 million in cash, before customary post-closing adjustments.

Additionally, on May 21, 2015, we sold $625.0 million of 10.0% Second Lien Notes and utilized a portion of the proceeds to repay the outstanding balance of our Credit Facility of approximately $468.2 million. Further, we exchanged approximately $504.1 million of 12.0% Third Lien Notes for approximately $279.8 million of our 2020 Senior Notes and $350.3 million of our 2021 Senior Notes, representing an exchange at 80.0% of the exchanged Unsecured Notes’ par value. Furthermore, on June 2, 2015, we exchanged approximately $20.0 million of Third Lien Notes for approximately $26.6 million of 2020 Senior Notes and $2.0 million of 2021 Senior Notes, representing an exchange at 70.0% of the exchanged Unsecured Notes’ par value. For further information regarding the Second Lien Notes, Third Lien Notes and updates to the Company’s debt covenants, see “—Note 9. Debt” to our consolidated financial statements. These transactions increased our liquidity position; however, due to depressed commodity prices, we continue to face the risk of a liquidity shortfall.

On May 18, 2015, we and Midstates Sub entered into the Seventh Amendment to the Credit Facility, which provided that, upon completion of the offering of the Second Lien Notes and Third Lien Notes exchange, the borrowing base of the Credit Facility would be reduced to $252.0 million. The Seventh Amendment also provided additional covenant flexibility. Additionally, we and Midstates Sub entered into the Eighth Amendment (as defined below), which increased the limitation on certain leases and lease agreements into which we may enter into during any period of twelve consecutive calendar months of the life of such leases from $2.0 million to $3.5 million. In October 2015, pursuant to the Ninth Amendment, the borrowing base was reaffirmed at $252.0 million.

In February 2016, we borrowed approximately $249.2 million under the Credit Facility, which represented the remaining undrawn amount that was available under the Credit Facility and as a result, as of February 9, 2016, we had a cash balance of approximately $335.7 million. 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. If commodity prices remain depressed or deteriorate further, the borrowing base under the Credit Facility will likely be reduced during the next redetermination. Any reduction in the borrowing base will result in a deficiency which must be repaid within 30 days or in six 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 the Credit Facility.

The terms of the Credit Facility and the indentures governing the Senior Notes require that some or all of the proceeds from asset sales, if any, must be used to permanently reduce outstanding debt, which could substantially reduce the amount of proceeds ultimately retained and therefore reduce the impact to our liquidity as a result of such sale. Further, 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. The ability to refinance any of the existing indebtedness on commercially reasonably terms will likely be materially and adversely impacted by the current conditions in the energy industry and our financial condition.

We have substantial interest payment obligations related to our debt over the next twelve months. As of December 31, 2015, payments due on contractual obligations during the next twelve months were approximately $188.0 million. The table below summarizes the cash interest payments on our various debt facilities (in thousands):

	2020 Senior Notes	2021 Senior Notes	Second Lien Notes	Third Lien Notes	Total
2016	$31,565	$32,158	$62,500	$53,230	$179,453
2017	$31,565	$32,158	$62,500	$54,300	$180,523
2018	$31,565	$32,158	$62,500	$55,391	$181,614
2019	$31,565	$32,158	$62,500	$56,504	$182,727
2020	$31,565	$32,158	$31,250	$83,830	$178,803
2021	$—	$16,079	$—	$—	$16,079

The above table excludes certain other commitments, such as fixed drilling commitments and operating leases. Our next scheduled interest payment is April 1, 2016 for $15.8 million to the holders of the 2020 Senior Notes and the Company is currently evaluating whether such interest payment will be made. If the payment is not made by April 1, 2016, we would have 30 days to cure such payment default before an event of default occurs.

The trading level of our debt is expressed as a percentage of the par value of the outstanding debt obligation, and our various outstanding debt obligations are currently trading at significant discounts to their par value. As of February 26, 2016, our 2020 Senior Notes were trading at 3.5% of par value, our 2021 Senior Notes were trading at 3.5% of par value, our Second Lien Notes were trading at 27.0% of par value and our Third Lien Notes were trading at 5.5% of par value. The trading level or market value of our debt is based upon many factors, including expectations regarding the likelihood of future repayment, and the amount recoverable in the event of a default, our ability to pay interest and the risk tolerance of each debt holder. As of February 26, 2016, although the principal balance of our total debt, excluding outstanding borrowings under our Credit Facility, was approximately $1.8 billion, the fair market value of our debt, based upon quoted trading prices, was approximately $0.2 billion.

As a result of the sustained commodity price decline and our substantial debt burden, we believe that forecasted cash and available credit capacity will not be sufficient to meet commitments as they come due over the next twelve months, and we will not be able to remain in compliance with current debt covenants unless we are able to successfully increase liquidity or deleverage. The uncertainty associated with the ability to meet commitments as they come due or to repay 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 the ability to meet obligations as they come due.

We are required to receive an unqualified auditors' opinion in relation to the 2015 consolidated financial statements. The failure to receive an unqualified opinion is an event of default under the Credit Facility that must be cured within 30 days of such event or waived by the lenders under the Credit Facility. In consideration of the uncertainty mentioned above, the report of our independent registered public accounting firm that accompanies our audited consolidated financial statements for the year ended December 31, 2015 in this Annual Report on Form 10-K contains an explanatory paragraph regarding an event of default under the Credit Facility, a projected additional debt covenant violation, and resulting lack of liquidity, which raises substantial doubt about our ability to continue as a going concern.

The report of our independent registered public accounting firm that accompanied our consolidated financial statements for the year ended December 31, 2014 also contained an explanatory paragraph regarding a projected debt covenant violation and resulting lack of liquidity raising substantial doubt about our ability to continue as a going concern; however, we obtained a waiver to the Credit Facility waiving any default as a result of receiving such explanatory paragraph in 2014. We have not received a similar waiver from our lenders under the Credit Facility for the explanatory paragraph to our 2015 independent registered public accounting firm report. As a result, we are in default under our Credit Facility. A failure to cure this default within 30 days will result in the acceleration of all of our indebtedness under the Credit Facility. If the lenders under our Credit Facility accelerate the loans outstanding thereunder, we will also be in default under the indentures governing our Senior Notes, in which case the lenders under the indentures governing our Senior Notes could accelerate the repayment thereof.

If lenders, and subsequently noteholders, accelerate the Company's outstanding indebtedness, it will become immediately due and payable and the Company will not have sufficient liquidity to repay those amounts. If we are unable to reach an agreement with our creditors prior to any of the above described accelerations, we could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

Our long-term debt with maturities summarized in Note 9 in the consolidated financial statements in this Annual Report on Form 10-K is reflected as a current liability in our consolidated balance sheet at December 31, 2015. The classification as a current liability is based on the uncertainty regarding our ability to cure the event of default discussed above and to comply with certain restrictive covenants contained in its Credit Facility and cross default/cross acceleration provisions in the indentures governing the Senior Notes.

In order to increase our liquidity to levels sufficient to meet the Company's commitments, we are currently undertaking a number of actions, including minimizing capital expenditures, aggressively managing working capital and further reducing our recurring operating expenses. We believe that even after taking these actions, we will not have sufficient liquidity to satisfy our debt service obligations, meet other financial obligations, and comply with our debt covenants. We have engaged financial and legal advisors to assist with, among other things, analyzing various strategic alternatives to address our liquidity and capital structure. We believe a filing under Chapter 11 of the U.S. Bankruptcy Code may provide the most expeditious manner in which to effect a capital structure solution. There can be no assurance we will be able to restructure our capital structure on terms acceptable to us, to our creditors, or at all.

Financial Ratio Covenants

The Credit Facility contains, among other standard affirmative and negative covenants, financial covenants including a maximum ratio of Total Senior Indebtedness to EBITDA (as defined therein) of not more than 1.0 to 1.0 and a minimum current ratio (as defined therein) of not less than 1.0 to 1.0. The Credit Facility also limits our ability to make any dividends, distributions or redemptions. Although we are not in compliance with all of our non-financial covenants (as discussed in the section above entitled Liquidity and Ability to Continue as a Going Concern), we were in compliance with these financial covenants at December 31, 2015.

Borrowing Base Redetermination

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. If commodity prices remain depressed or deteriorate further, the borrowing base under the Credit Facility will likely be reduced. Since the Credit Facility is fully drawn, any reduction in the borrowing base will result in a deficiency in the amount that our borrowings exceed the borrowing base, and such deficiency must be repaid 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 the Credit Facility.

Cross Default Provisions

The 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 the 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 accelerate the repayment of such 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.

Our Capital Requirements

At December 31, 2015, our liquidity was $330.3 million, consisting of $249.2 million of available borrowing capacity under our Revolving Credit Facility and $81.1 million of cash and cash equivalents. In February 2016, we borrowed approximately $249.2 million under the Credit Facility, which represented the remaining undrawn amount that was available under the Credit Facility and as a result, as of February 9, 2016, we had a cash balance of approximately $335.7 million.

Expenditures for exploration and development of oil and natural gas properties and payments for interest on our outstanding debt are the primary uses of our capital resources. As of December 31, 2015, we had three drilling rigs in operation, and plan to reduce our operated drilling rigs to one rig by the end of March 2016. Additionally, our interest payment obligations are substantial and total approximately $188.0 million for the year ended December 31, 2016. While the debt restructuring transaction completed in May 2015 improved our current liquidity, due to depressed commodity prices, we continue to face the risk of a liquidity shortfall.

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 and service our debt obligations would be reduced and our liquidity would be negatively impacted. In order to increase our liquidity to levels sufficient to meet the Company's commitments, we are currently undertaking a number of actions, including minimizing capital expenditures, aggressively managing working capital and further reducing our recurring operating expenses. We believe that even after taking those actions, we will not have sufficient liquidity to satisfy our debt service obligations, meet other financial obligations, and comply with our debt covenants. We have engaged financial and legal advisors to assist with, among other things, analyzing various strategic alternatives to address our liquidity and capital structure. We believe a filing under Chapter 11 of the U.S. Bankruptcy Code may provide the most expeditious manner in which to effect a capital structure solution. There can be no assurance we will be able to restructure our capital structure on terms acceptable to us, to our creditors, or at all.

Significant Sources of Capital

Reserve-based Credit Facility.

We maintain a $750.0 million Credit Facility with a current borrowing base of $252.0 million. At December 31, 2015, we had no amounts drawn on the Credit Facility and had outstanding letters of credit obligations totaling $2.8 million. In February 2016, we fully drew down the remaining availability under the Credit Facility.

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, the weighted average interest rate was 2.8%.

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 will occur in April 2016.

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. If commodity prices remain depressed or deteriorate further, the borrowing base under the Credit Facility will likely be reduced. Since the Credit Facility is fully drawn, any reduction in the borrowing base will result in a deficiency in the amount that our borrowings exceed the borrowing base, which must be repaid 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 the Credit Facility.

On March 24, 2015, we and Midstates Sub entered into the Sixth Amendment to the Credit Facility (the "Sixth Amendment'). The Sixth Amendment amended the required ratio of net consolidated indebtedness to EBITDA under the Credit Agreement for each of the fiscal quarters in 2015 from 4.0:1.0 to 4.5:1.0. Additionally, the Sixth Amendment amended the mortgage requirements under the Credit Facility to provide for an increase from 80.0% to 90.0% in the percentage of properties included in the borrowing base that are required to be subject to mortgages for the benefit of the lenders.

On May 21, 2015, we and Midstates Sub entered into the Seventh Amendment to the Credit Facility. The Seventh Amendment provided that, with the completion of the offering of the Second Lien Notes and Third Lien Notes exchange (both discussed below), our borrowing base would be reduced to approximately $252.0 million. The Seventh Amendment also eliminated the required ratio of net consolidated indebtedness to EBITDA covenant and added a ratio of Total Senior Indebtedness (as defined therein) to EBITDA of not more than 1.0 to 1.0.

On August 5, 2015, we and Midstates Sub entered into the Eighth Amendment to the Credit Facility, (the "Eighth Amendment'). The Eighth Amendment increased the limitation on certain leases and lease agreements into which we may enter into during any period of twelve consecutive calendar months of the life of such leases from $2.0 million to $3.5 million.

On October 14, 2015, we entered into the Ninth Amendment to the Credit Facility which, among other things, reaffirmed the borrowing base at $252.0 million and provided flexibility for certain specified asset sales by confirming the amount of the borrowing base reduction if any such sale should occur.

The Credit Facility contains, among other standard affirmative and negative covenants, financial covenants including a maximum ratio of Total Senior Indebtedeness to EBITDA (as defined therein) of not more than 1.0 to 1.0 and a minimum current ratio (as defined therein) of not less than 1.0 to 1.0. The Credit Facility also limits our ability to make any dividends, distributions, or redemptions.

2020 Senior Notes.

On October 1, 2012, we issued $600.0 million in aggregate principal amount of 2020 Senior Notes conducted pursuant to Rule 144A and Regulation S under the Securities Act. In October 2013, these notes were exchanged for an equal principal amount of identical registered notes. The 2020 Senior Notes rank pari passu in right of payment with the 2021 Senior Notes, the Second Lien Notes and Third Lien Notes; however, the 2021 Senior Notes and 2020 Senior Notes are effectively junior to the extent of the value of the collateral securing our Credit Facility, the Second Lien Notes and the Third Lien Notes. The 2020 Senior Notes were co-issued on a joint and several basis by us and 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 there are no other subsidiaries. The indenture governing the 2020 Senior Notes (the "2020 Senior Notes Indenture") does not impose any significant restrictions on the ability of Midstates Sub to transfer assets to, pay dividends to, make investments in or make loans to the Company or limit the ability of the Company to transfer assets to, pay dividends to, make investments in or make loans to Midstates Sub.

Upon the occurrence of certain change of control events, as defined in the 2020 Senior Notes 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 101.0% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

As part of the debt restructuring transaction, on May 21, 2015 and June 2, 2015, a total of approximately $306.4 million aggregate principal amount of 2020 Senior Notes were exchanged for Third Lien Notes.

2021 Senior Notes.

On May 31, 2013, we issued $700.0 million in aggregate principal amount of 2021 Senior Notes. In October 2013, these notes were exchanged for an equal principal amount of identical registered notes. The 2021 Senior Notes rank pari passu in right of payment with the 2020 Senior Notes, Second Lien Notes and Third Lien Notes; however, the 2021 Senior Notes and 2020 Senior Notes are effectively junior to the extent of the value of the collateral securing our Credit Facility, the Second Lien Notes and the Third Lien Notes. The 2021 Senior Notes were co-issued on a joint and several basis by us and our wholly owned subsidiary, Midstates Sub. The indenture governing the 2021 Senior Notes (the "2021 Senior Notes Indenture") does not impose any significant restrictions on the ability of Midstates Sub to transfer assets to, pay dividends to, make investments in or make loans to the Company or limit the ability of the Company to transfer assets to, pay dividends to, make investments in or make loans to Midstates Sub.

Upon the occurrence of certain change of control events, as defined in the 2021 Senior Notes Indenture, each holder of the 2021 Senior Notes will have the right to require that we repurchase all or a portion of such holder's 2021 Senior Notes in cash at a purchase price equal to 101.0% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

As part of the debt restructuring, on May 21, 2015 and June 2, 2015, a total of approximately $352.3 million aggregate principal amount of 2021 Senior Notes were exchanged for Third Lien Notes.

Second Lien Notes

On May 21, 2015, we and Midstates Sub issued and sold $625.0 million aggregate principal amount of Second Lien Notes in a private placement conducted pursuant to Rule 144A under the Securities Act. In November 2015, these notes were exchanged for an equal principal amount of identical registered notes. The Second Lien Notes mature on the earlier of June 1, 2020 or 12 months after the maturity date of our Credit Facility (including any extension or refinancing of such facility). The Second Lien Notes have an interest rate of 10.0% and interest is payable semi-annually on June 1 and December 1 of each fiscal year. The Second Lien Notes are unconditionally guaranteed, jointly and severally, on a senior secured basis by each of our future restricted subsidiaries (the “Guarantors”) and will be initially secured by second-priority liens on substantially all of our and the Guarantors’ assets that secure our Credit Facility. The indenture governing the Second Lien Notes (the “Second Lien Notes Indenture”) does not impose any significant restrictions on the ability of Midstates Sub to transfer assets to, pay dividends to, make investments in or make loans to the Company or limit the ability of the Company to transfer assets to, pay dividends to, make investments in or make loans to Midstates Sub.

The Second Lien Notes are our senior secured obligations and rank effectively junior to our obligations under the Credit Facility, effectively senior to our existing and future unsecured indebtedness, effectively senior to our Third Lien Notes and all future junior lien obligations, effectively junior to all existing and future secured indebtedness secured by assets not constituting collateral under the Second Lien Notes, pari passu with all of our existing and future senior debt, structurally subordinated to all existing and future indebtedness of any non-Guarantor subsidiaries and senior to any existing or future subordinated debt.

Upon the occurrence of certain change of control events, as defined in the indenture governing the Second Lien Notes, each holder of the Second Lien Notes will have the right to require that we repurchase all or a portion of such holder’s Second Lien Notes in cash at a purchase price equal to 101.0% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

Third Lien Notes

On May 21, 2015 and June 2, 2015, we issued approximately $504.1 million and $20.0 million, respectively, in aggregate principal amount of Third Lien Notes in a private placement and in exchange for an aggregate of $306.4 million of the 2020 Senior Notes and $352.3 million of the 2021 Senior Notes. In November 2015, these notes were exchanged for an equal principal amount of identical registered notes. The Third Lien Notes are unconditionally guaranteed, jointly and severally, on a senior secured basis by each of the Guarantors. The Third Lien Notes are initially secured by third-priority liens on substantially all of the Company’s assets that secure the Credit Facility. The Third Lien Notes have an interest rate of 12.0%, consisting of cash interest of 10.0% and paid-in-kind interest of 2.0%, per annum and mature on the earlier of June 1, 2020 or 12 months after the maturity date of our Credit Facility (including any extension or refinancing of such facility). Cash interest is payable semi-annually on June 1 and December 1 of each fiscal year. Paid-in-kind interest increases the outstanding principal balance of the Third Lien Notes on June 1 and December 1 of each fiscal year. The indenture governing the Third Lien Notes (the “Third Lien Notes Indenture”) does not impose any significant restrictions on the ability of Midstates Sub to transfer assets to, pay dividends to, make investments in or make loans to the Company or limit the ability of the Company to transfer assets to, pay dividends to, make investments in or make loans to Midstates Sub.

The Third Lien Notes are our senior secured obligations and rank effectively junior to our obligations under the Credit Facility and Second Lien Notes to the extent of the value of the collateral securing such indebtedness, effectively senior to our existing and future unsecured indebtedness to the extent of the value of the collateral securing the Third Lien Notes, effectively senior to all future junior lien obligations that rank below a third-priority basis to the extent of the value of the collateral securing the Third Lien Notes, effectively junior to all existing and future secured indebtedness secured by assets not constituting collateral under the Third Lien Notes, equal in right of payment to all of our existing and future senior debt, structurally subordinated to all existing and future indebtedness of any non-Guarantor subsidiaries and senior in right of payment to any existing or future subordinated debt.

Upon the occurrence of certain change of control events, as defined in the indenture governing the Third Lien Notes, each holder of the Third Lien Notes will have the right to require that we repurchase all or a portion of such holder’s Third Lien Notes in cash at a purchase price equal to 101.0% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

Debt Covenants

The Credit Facility, as amended, contains, among other standard affirmative and negative covenants, financial covenants including a maximum ratio of Total Senior Indebtedness to EBITDA (as defined therein) of not more than 1.0:1.0 and a minimum current ratio (as defined therein) of not less than 1.0 to 1.0. The Credit Facility also limits our ability to make any dividends, distributions or redemptions. Although we are not in compliance with all of our non-financial covenants (as discussed in the section above entitled Liquidity and Ability to Continue as a Going Concern), we were in compliance with these financial covenants at December 31, 2015.

The indentures governing the 2020 Senior Notes, 2021 Senior Notes, Second Lien Notes and Third Lien Notes contain 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.

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 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:

	For the Years Ended December 31,		
	2015	**2014**	**2013**
		(in thousands)	
Net cash provided by operating activities	$213,383	$351,544	$237,588
Net cash used in investing activities	(294,556)	(404,264)	(1,204,332)
Net cash provided by financing activities	150,709	31,114	981,029
Net change in cash	**$69,536**	**$(21,606)**	**$14,285**

Cash flows provided by operating activities

Net cash provided by operating activities was $213.4 million, $351.5 million, and $237.6 million for the years ended December 31, 2015, 2014 and 2013, respectively. The decrease in net cash provided by operating activities for the year ended December 31, 2015 compared to the year ended December 31, 2014 is primarily the result of a decrease in our oil and gas revenues of $330.9 million partially offset by increased settlements of derivatives of $186.0 million. 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.

Cash flows used in investing activities

We had net cash used in investing activities of $294.6 million, $404.3 million, and $1.2 billion during the years ended December 31, 2015, 2014, and 2013, respectively. The decrease in net cash used in investing activities for the year ended December 31, 2015 as compared to the year ended December 31, 2014 was due to a reduced drilling program in the period as a result of depressed commodity prices. During the year ended December 31, 2015, $336.9 million was spent on our drilling program, partially offset by $42.4 million in proceeds received from the Dequincy Divestiture. During the year ended December 31, 2014, $556.4 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 (discussed further in “—Note 7. Acquisitions and Divestitures of Oil and Gas Properties” to our consolidated financial statements) and $1.4 million in other asset sales. During the year ended December 31, 2013, $584.2 million was spent on our drilling program and $620.1 million for the Anadarko Basin Acquisition.

Cash flows provided by financing activities

Net cash provided by financing activities was $150.7 million, $31.1 million, and $981.0 million for the years ended December 31, 2015, 2014, and 2013, respectively. The increase in net cash provided by financing activities for the year ended December 31, 2015 as compared to the year ended December 31, 2014 was driven by the issuance of the Second Lien Notes for proceeds of $625.0 million and borrowings from the Credit Facility of $33.0 million. These proceeds were partially offset by repayments on the Credit Facility of $468.2 million and $34.4 million paid for restructuring transaction costs. For the year ended December 31, 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 $700.0 million and borrowings under the Credit Facility of $341.5 million, offset by repayments of our reserve based revolving credit facility of $34.3 million. Our debt, including debt classified as current, was $1.9 billion, $1.7 billion and $1.7 billion at December 31, 2015, 2014 and 2013, respectively.

Other Items

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2015 (in thousands):

		Payments Due by Period		
	Total	**1 - 3 years**	**4 - 5 years**	**More than 5 years**
Reserve based revolving credit facility(1)	$—	$—	$—	$—
2020 Senior Notes				
Principal payments	293,625	—	293,625	—
Interest payments	157,825	94,695	63,130	—
2021 Senior Notes				
Principal payments	347,652	—	—	347,652
Interest payments	176,869	96,474	64,316	16,079
Second Lien Notes				
Principal payments	625,000	—	625,000	—
Interest payments	281,250	187,500	93,750	—
Third Lien Notes				
Principal payments	524,121	—	524,121	—
Interest payments	303,255	162,921	140,334	—
Drilling contracts(2)	3,468	3,468	—	—
Non-cancellable office lease commitments(2)	7,463	5,289	1,932	242
Seismic contracts(2)	3,192	3,192	—	—
Asset retirement obligations(3)	18,708	—	—	18,708
Net minimum commitments(4)	**$2,742,428**	**$553,539**	**$1,806,208**	**$382,681**

(1) Amount excludes interest on our reserve based revolving credit facility as both the amount borrowed and applicable interest rate is variable. As of December 31, 2015, we had not drawn down on our reserve based revolving credit facility. However, subsequent to the year ended December 31, 2015, we have fully drawn down our Credit Facility resulting in borrowings of approximately $252.0 million, including approximately $2.8 million of outstanding letters of credit. See "—Note 9. Debt" for further information.

(2) See "—Note 15. Commitments and Contingencies" for a description of operating lease, drilling contract, seismic contract and other obligations.

(3) 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. Asset Retirement Obligations".

(4) Excluded from these amounts are any payments that may become necessary under our minimum volume requirements in our gas purchase, gathering and processing contract in the Mississippian Lime region; please see the Marketing and Major Purchasers discussion in the Business section of this document.

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 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:

Full Cost Method of Accounting and Proved 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, 2015, 2014, and 2013 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.

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

Based upon commodity pricing for the first quarter of 2016, we expect to recognize a further full cost impairment that is likely to be material to our net earnings. While inherently imprecise and difficult to measure, we estimate our first quarter 2016 impairment will be approximately $100.0 million to $150.0 million. Our full cost impairments have no impact to our cash flow or liquidity.

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 and such variances have historically not been significant.

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.

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.

The accounting guidance for asset retirement obligations requires that a liability for the present value of estimated future retirement obligations be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The discounted liability is then subsequently accreted to its new present value. The amount of liability recorded for our asset retirement obligation is significantly impacted by our estimate of when the liability will be settled because of the discounting effect that occurs to reflect the liability at the present value of the future obligation. For example, at December 31, 2015, an increase of 5 years in the estimated settlement date used for asset retirement purposes would impact the present value of our asset retirement obligation by $(0.2) million, while a decrease of 5 years in the estimated settlement date would have an impact of $0.9 million.

Income Taxes. The amount of income taxes recorded requires interpretations of complex rules and regulations of federal, state, and provincial tax jurisdictions. We recognize current tax expense based on estimated taxable income for the current period and the applicable statutory tax rates. We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized. In light of the impairment of oil and gas properties, we have recorded a $689.4 million valuation allowance during the year against our federal and state 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 carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment.

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.

Recent Accounting Pronouncements. In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. ASU 2014-09 provides guidance concerning the recognition and measurement of revenue from contracts with customers. The objective of ASU 2014-09 is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. ASU 2014-09 requires an entity to (i) identify the contract(s) with a customer, (ii) identify the performance obligations in the contract(s), (iii) determine the transaction price, (iv) allocate the transaction price to the performance obligations in the contract(s), and (v) recognize revenue when, or as, the entity satisfies a performance obligation. ASU 2014-09 will be effective for us beginning on January 1, 2018, including interim periods within that reporting period, considering the one year deferral provided by ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. The standard permits the use of either the retrospective or cumulative effect transition method and early adoption is permitted. We have not selected a transition method and are evaluating the impact this standard will have on our consolidated financial statements and related disclosures.

In April 2015, the FASB issued ASU 2015-03, *Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs"* and in August 2015 issued ASU 2015-15, *Interest—Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements—Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting (SEC Update).* The ASUs provide that the debt issuance costs are similar to debt discounts and in effect reduce the proceeds of borrowings. ASU No. 2015-03 amends the FASB ASC to require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the related liability. Prior to the amendment, debt issuance costs were reported in the balance sheet as an asset. ASU No. 2015-15 further clarified that given ASU No. 2015-03’s silence on debt issuance costs related to revolving credit facilities, the SEC would not object to debt issuance costs for revolving credit facilities being deferred and presented as an asset. The amended guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015; however we elected to early adopt effective December 31, 2015. The election requires retrospective application and represents a change in accounting principle. As a result of the adoption, the December 31, 2014 consolidated balance sheet has been adjusted. See "—Note 3. Summary of Significant Accounting Policies" in the consolidated financial statements for more discussion on the impact on the consolidated balance sheet.

In September 2015, the FASB issued ASU 2015-16, *Business Combinations (Topic 806): Simplifying the Accounting for Measurement Period Adjustments* ("ASU 2015-16"). ASU 2015-16 changes the accounting for measurement period adjustments by eliminating the requirement that such adjustments are made retrospectively. As a result, such measurement period adjustments will be recognized in the reporting period in which the adjustment was determined. ASU 2015-16 is applied prospectively to adjustments to provisional amounts that occur after the effective date. ASU 2015-16 is effective for us beginning on January 1, 2016. We do not believe the adoption of ASU 2015-16 will have a material impact on our financial position, results of operations or cash flows.

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes,* which requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position to simplify the presentation of deferred income taxes. The standard is effective prospectively for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017, with early adoption permitted. As of December 31, 2015, we elected to early adopt the pronouncement on a prospective basis. Adoption of this amendment did not have an effect on the Company's financial position or results of operations, and prior periods were not retrospectively adjusted.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* ("ASU 2016-02"). ASU 2016-02 establishes a right-of-use ("ROU") model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are currently evaluating the impact this standard will have on our consolidated financial statements and related disclosures.

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. Risk Management and Derivative Instruments" to our consolidated financial statements. No derivative instruments are currently outstanding and none were outstanding at December 31, 2015.

Commodity price exposure. We are exposed to market risk as the prices of oil, NGLs and natural gas fluctuate due to changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have in the past hedged and in the long-term, expect to hedge a significant portion of our future production. However, given the current low commodity price environment, we may limit the extent of our hedging program in the near-term as appropriate. We currently have no derivative contracts for any period subsequent to 2015. As such, unless new hedging contracts are put in place, cash payments from settled derivative contracts will not be received in 2016 and future periods due to the expiration of all of our hedging contracts.

We have historically utilized derivative financial instruments to manage risks related to changes in oil and natural gas prices. For the year ended December 31, 2015, we utilized fixed price swaps to reduce the volatility of oil and natural gas prices on a portion of our expected oil and natural gas 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.

As of December 31, 2014, 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 are the derivative instruments discussed above. At December 31, 2014, all of our commodity derivative contracts were with seven counterparties and were 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, 2015, we had no indebtedness outstanding under our Credit Facility, $293.6 million outstanding in 2020 Senior Notes, which bear interest at 10.75%, $347.7 million outstanding in 2021 Senior Notes, which bear interest at 9.25%, $625.0 million outstanding in Second Lien Notes, which bear interest at 10.0% and $529.7 million in Third Lien Notes, inclusive of $5.5 million of accrued paid-in kind interest, which bear interest at 12.0%. In February 2016, the Company borrowed approximately $249.2 million under the Credit Facility, which represented the remaining undrawn amount that was available under the Credit Facility and as a result, as of February 9, 2016, the Company had a cash balance of approximately $335.7 million.

At December 31, 2015, 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. 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 future oil and natural gas derivative arrangements may expose us to credit risk in the event of nonperformance by counterparties.

While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and 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. 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-15I and 15d-15I 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, 2015 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, 2015.

Material Weakness in Internal Control over Financial Reporting and Remediation Efforts. During the second quarter of 2015, we identified a material weakness in our internal control over financial reporting related to the review of our Consolidated Statements of Cash Flows. This material weakness resulted from errors in our restated amounts within our Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012, which were reported in Item 5. *Other Information*, of our Quarterly Report on Form 10-Q for the interim period ended March 31, 2015. Although we believed the errors to be immaterial, we revised the restated amounts for the years ended December 31, 2013 and 2012 in Item 5. *Other Information,* of our Quarterly Report on Form 10-Q for the interim period ended June 30, 2015.

Upon identification of the errors in Item 5. *Other Information*, of our Quarterly Report on Form 10-Q for the interim periods ended March 31, 2015 and June 30, 2015, we implemented additional review procedures of the control targeted to ensuring the completeness and accuracy of our Consolidated Statements of Cash Flows.

Changes in Internal Control over Financial Reporting. Except for the remediation of the material weakness discussed above, there were no changes in internal control over financial reporting during the quarter ended December 31, 2015 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III.

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

The following table shows information for our executive officers and members of the Board of Directors as of the date of the filing of this Annual Report on Form 10-K

Name	Age	Title
Frederic F. Brace	58	Interim President and Chief Executive Officer and Director
Alan J. Carr(1)(2)(3)(4)	46	Director
Bruce Stover(1)(2)(3)	66	Director
Robert E. Ogle(1)(2)(3)(4)	65	Director
Nelson M. Haight	51	Executive Vice President, Chief Financial Officer and Chief Accounting Officer
Mitchell G. Elkins	56	Executive Vice President—Operations
Scott C. Weatherholt	38	Vice President—Land, General Counsel and Corporate Secretary

(1) Member of the Nominating and Governance Committee.

(2) Member of the Compensation Committee.

(3) Member of the Audit Committee.

(4) Member of the Special Committee.

Officers and Directors

Frederic F. Brace has served as our Interim President and Chief Executive Officer since March 18, 2015 and as a member of our Board of Directors since March 9, 2015. Mr. Brace has over twenty years of experience in business management and board representations. He is currently Chairman and Chief Executive Officer of Beaucastel LLC and Sangfroid Advisors Ltd. Previously, Mr. Brace worked for Niko Resources, Ltd., an oil and gas company, from August 2013 to December 2014 serving first as Senior Advisor and then as President of the company. From 1988 to 2008, Mr. Brace worked at the UAL Corporation (now United Continental Holdings, Inc.), the parent company of United Airlines, Inc. and Continental Airlines, Inc., where he served as Executive Vice President and Chief Financial Officer of UAL Corporation and United Airlines, Inc. from 2002 to 2008. Mr. Brace is currently a member of the board of directors of Anixter International and several private companies and has previously served on the board of numerous public and private companies. He received his BS in Industrial Engineering from the University of Michigan in 1980 and his MBA with a specialization in finance from the University of Chicago Graduate School of Business in 1982. We believe Mr. Brace's knowledge of the energy industry and expertise in representing public and private companies allows him to provide valuable insights to our Board of Directors.

Bruce Stover has served as a member of our Board of Directors since March 18, 2015. Mr. Stover has over forty years of experience in the oil and gas industry and has an extensive background in mergers and acquisitions as well as global operations and business development. Mr. Stover has served on the board of directors of the Bristow Group, Inc. since 2009 and as Chairman of the Compensation Committee of such board since 2012. Prior to joining the board of Bristow Group, Inc., he was a founding member of the management team of Endeavor International Corporation, where he served as Executive Vice President, Operations and Business Development, from 2003 to 2010. Before serving at Endeavor International Corporation, Mr. Stover was Senior Vice President, Worldwide Business Development for Anadarko Petroleum Corporation responsible for evaluating and securing domestic and international business opportunities. While there, Mr. Stover also served as President and General Manager of Anadarko Petroleum Corporation's Algerian subsidiary. He began his career as an engineer with Amoco Production Company. We believe Mr. Stover's experience in the energy industry and expertise in representing public and private companies brings important experience and skill to our Board of Directors.

Alan J. Carr has served as a member of our Board of Directors since March 9, 2015. Mr. Carr is an investment professional with twenty years of experience working from the principal and advisor side on complex, process-intensive financial situations. Mr. Carr is the founder of Drivetrain Advisors, a fiduciary services firm that supports the investment community in legally- and process-intensive investments as a representative, director, or trustee. Prior to founding Drivetrain Advisors in 2013, Mr. Carr was a Managing Director at Strategic Value Partners, LLC where he led financial restructurings for companies in North America and Europe, working in both the US and Europe over nine years. Prior to joining Strategic Value Partners, Mr. Carr was a corporate attorney at Skadden, Arps, Slate, Meagher & Flom. Mr. Carr currently serves on the board of directors of Tanker Investments Ltd. and Brookfield DTLA Fund Office Trust Investor Inc. Mr. Carr has experience serving on boards of a variety of companies in North America, Europe and Asia. He received his B.A. in Economics and Sociology from Brandeis University in 1992 and his J.D. from Tulane Law School in 1995. We believe Mr. Carr's extensive financial expertise and experience in representing public and private companies in complex financial situations brings important experience and skill to our Board of Directors.

Robert E. Ogle has served as a member of our Board of Directors since March 18, 2015. Mr. Ogle has been a certified public accountant for over thirty-five years with experience in the upstream and downstream oil and gas industries, retail, airline and service industries, representing debtors, creditors, investors and governmental agencies. Mr. Ogle is currently a Senior Advisor with The Claro Group. Prior to joining The Claro Group, he was a founder and Chief Financial Officer for Ute Energy LLC from 2005 to 2009. Before serving there, Mr. Ogle was the Director of Corporate Recovery Services at Huron Consulting and prior to joining Huron Consulting was a Corporate Recovery Services Partner at Arthur Andersen, where he started their corporate recovery services practice in Houston, Texas. While at Arthur Andersen, Mr. Ogle provided services to Link Energy, Continental Airlines, Delta Airlines, United Airlines, Edge Petroleum Corporation, Orion Refinery, Entergy and many others. Mr. Ogle co-founded the Houston Chapter of the Turnaround Management Association. We believe Mr. Ogle's extensive financial expertise and experience in representing public and private companies brings important experience and skill to our Board of Directors.

Nelson M. Haight has served as our Executive Vice President and Chief Financial Officer since January 2015, and previously served as Senior Vice President and Chief Financial Officer from January 2014 through January 2015, and as our Chief Accounting Officer from August 2013 through January 2014. Mr. Haight previously served as our Vice President and Controller from December 2011 to August 2013. Mr. Haight is a Certified Public Accountant and prior to joining the Company, Mr. Haight was a partner with the audit firms of GBH CPAs from November 2008 to December 2011 and Malone Bailey, PC from July 2007 to November 2008. Prior to those positions, Mr. Haight served in a variety of public accounting and finance roles and began his career in 1988 with Arthur Andersen and Co. Mr. Haight holds a bachelor's degree and a master's degree in public accounting from the University of Texas at Austin.

Mitchell G. Elkins has served as our Executive Vice President of Operations since February 2014 after his previous role of Vice President of Drilling and Completions, which he held since 2012. Prior to joining the Company, Mr. Elkins worked as the International Drilling Manager for Transatlantic in Instanbul, Turkey from May 2011 through January 2012 and the Drilling and Completions manager for Apache in their Australian operations from July 2006 through April 2011. Prior to that, Mr. Elkins held a variety of roles for Unocal as well as Apache, and also owned a project management company supporting clients such as Apache, Chevron, Perenco, Shell and others in international operations. Mr. Elkins holds a BS in Control Engineering with a Petroleum Production Base from the University of Texas—Permian Basin.

Scott C. Weatherholt joined the Company in February 2015 and currently serves as Vice President—General Counsel & Corporate Secretary and Vice President—Land. For approximately 10 years prior to joining the Company, Mr. Weatherholt was an attorney at Samson Resources Company, located in Tulsa, Oklahoma, where he had most recently held the position of Assistant General Counsel and oversaw Samson's day-to-day legal activities as well as had managerial responsibility for Samson's Land Administration and Division Order Departments. Prior to Samson, Mr. Weatherholt had been engaged in the private practice of law in Tulsa, Oklahoma with the Pray Walker law firm, with an emphasis upon energy and royalty owner litigation. Mr. Weatherholt graduated from the University of Oklahoma with a B.B.A. degree in Finance and the University of Oklahoma College of Law where he received his Juris Doctorate degree. Mr. Weatherholt is a member of the American Bar Association and Oklahoma Bar Association as well as the Association of Corporate Counsel. Mr. Weatherholt is actively involved with the Oklahoma Independent Petroleum Association and is a member of OIPA's legislative and legal committees.

Board Structure and Corporate Governance

The Board of Directors believes that sound governance practices and policies provide an important framework to assist it in fulfilling its duty to stockholders. The Company's Corporate Governance Guidelines cover the following principal subjects:

- role and functions of the Board of Directors and its Chairman;
- qualifications and independence of directors;
- size of the Board of Directors and director selection process;

- committee functions and independence of committee members;
- meetings of non-employee directors;
- self-evaluation;
- ethics and conflicts of interest (a copy of the current "Code of Business Conduct and Ethics" is posted on the Company's website at *www.midstatespetroleum.com*);
- compensation of the Board of Directors;
- succession planning;
- access to senior management and to independent advisors;
- new director orientation; and
- continuing education.

The "Corporate Governance Guidelines" are posted on the Company's website at *www.midstatespetroleum.com*. The Corporate Governance Guidelines will be reviewed periodically and as necessary by the Company's Nominating and Governance Committee, and any proposed additions to or amendments of the Corporate Governance Guidelines will be presented to the Board of Directors for its approval.

The Company's Board of Directors currently consists of seven seats, three of which are currently vacant. The Company's directors serve for a one year term. Directors may be removed from office either for or without cause upon the affirmative vote of the holders of at least 75% of the outstanding shares of stock of the Company entitled to vote generally for the election of directors.

Mr. Thomas C. Knudson served as Lead Director of the Board of Directors from March 2014 to April 2015 and as Chairman of the Board of Directors from April 2015 to November 2015. In December 2015, Mr. Knudson announced his intent to not stand for re-election to the Board of Directors and resigned his position as Chairman of the Board. Mr. Stover was then appointed to serve as Chairman of the Board of Directors. Dr. Peter J. Hill served as our Interim President and Chief Executive Officer from March 2014 to March 18, 2015, and through March 9, 2015 also served as a director. Mr. Frederic F. Brace was appointed as a director on March 9, 2015 and as Interim President and Chief Executive Officer on March 18, 2015.

The Board recognizes that one of its key responsibilities is to evaluate and determine its optimal leadership structure so as to provide independent oversight of management. The Board understands that the optimal Board leadership structure may vary as circumstances warrant. Consistent with this understanding, non-management directors consider the Board's leadership structure on an annual basis. All directors are encouraged to suggest the inclusion of agenda proposals or revisions to meeting materials, and any director is free to raise at any Board meeting proposals that are not on the agenda for that meeting. All of these principles are set forth in the Company's Corporate Governance Guidelines.

The Board of Directors as a whole oversees the Company's assessment of major risks and the measures taken to manage such risks. For example, the Board of Directors:

- oversees management of the Company's commodity price risk through regular review with executive management of the Company's derivatives strategy, and the oversight of the Company's policy that limits the Company's authority to enter into derivative commodity price instruments to a specified level of production, above which management must seek Board approval;
- has established specific dollar limits on the commitment authority of members of senior management and requires Board approval of expenditures exceeding that authority and of other material contracts and transactions; and
- reviews management's capital spending plans, approves the Company's capital budget and requires that management present for Board review significant departures from those plans.

The Company's Audit Committee is responsible for overseeing the Company's assessment and management of financial reporting and internal control risks, as well as other financial risks, such as the credit risks associated with counterparty exposure. Management and the Company's internal audit function and independent registered public accountants report regularly to the Audit Committee on those subjects.

The Board of Directors regularly meets in executive session without the presence of the Interim President and Chief Executive Officer or other members of management. The Chairman of the Board presides at these meetings and provides the Board of Directors' guidance and feedback to the President and Chief Executive Officer and the Company's management team. Further, the Board of Directors has complete access to the Company's management team.

The Board of Directors held 14 meetings during 2015, and its independent directors met in executive session four times during 2015. During 2015, each of our directors attended at least 75% of the meetings of the Board of Directors and the meetings of the committees of the Board of Directors on which that director served.

The Board of Directors has four standing committees: the Audit Committee, the Compensation Committee, the Nominating and Governance Committee and the Special Committee.

Audit Committee.

Information regarding the functions performed by the Audit Committee and its membership is set forth in the "Audit Committee Report" included herein and also in the "Audit Committee Charter" that is posted on the Company's website at *www.midstatespetroleum.com*.

The members of the Audit Committee are Messrs. Stover, Carr and Ogle (Chairman). Messrs. Stover, Carr and Ogle each joined the Audit Committee in March 2015. The Audit Committee held ten meetings during 2015.

Compensation Committee.

Responsibilities of the Compensation Committee, which are discussed in detail in the "Compensation Committee Charter" that is posted on the Company's website at *www.midstatespetroleum.com*, include among other duties, the responsibility to:

- periodically review the compensation, employee benefit plans and fringe benefits paid to, or provided for, executive officers of the Company;
- approve the annual salaries, bonuses and share-based awards paid to the Company's executive officers;
- periodically review and recommend to the full Board of Directors total compensation for each non-employee director for services as a member of the Board of Directors and its committees; and
- exercise oversight of all matters of executive compensation policy.

The Compensation Committee is delegated all authority of the Board of Directors as may be required or advisable to fulfill the purposes of the Compensation Committee. The Compensation Committee may form and delegate some or all of its authority to subcommittees when it deems appropriate. Meetings may, at the discretion of the Compensation Committee, include members of the Company's management, other members of the Board of Directors, consultants or advisors, and such other persons as the Compensation Committee or its chairperson may determine in an informational or advisory capacity.

Our Chief Executive Officer annually reviews the competitive pay position and the performance of each member of senior management other than himself. Our Chief Executive Officer's conclusions and recommendations, including those for base salary adjustments and award amounts for the current year and target annual award amounts for the next year under our Bonus Plan, are presented to the Compensation Committee. The Compensation Committee makes all compensation decisions and approves all share-based awards for the Named Executive Officers and other officers at or above the vice president level. The Compensation Committee may exercise its discretion in modifying any compensation adjustment or awards to any executive officer, including reducing or increasing the payment amount for one or more components of such awards.

Our Board of Directors annually considers the performance of our Chief Executive Officer. The Compensation Committee determines all components of our Chief Executive Officer's compensation and meets outside the presence of all of our executive officers to consider appropriate compensation for our Chief Executive Officer.

The Compensation Committee has the sole authority to retain, amend the engagement with, and terminate any compensation consultant to be used to assist in the evaluation of director, CEO or officer compensation, including employment contracts and change in control provisions. The Compensation Committee has sole authority to approve the consultant's fees and other retention terms and has authority to cause the Company to pay the fees and expenses of such consultants. During 2015, the Compensation Committee engaged the services of Longnecker & Associates to serve as its independent compensation consultant. The Compensation Committee assessed the independence of Longnecker pursuant to Securities and Exchange Commission rules and considered, among other things, whether Longnecker provides any other services to us, the policies of Longnecker that are designed to prevent any conflict of interest between Longnecker, the Compensation Committee and us, any personal or business relationship between Longnecker and any member of the Compensation Committee or between Longnecker and one of our executive officers and whether Longnecker owns any shares of our common stock. The terms of Longnecker's engagement are set forth in an engagement agreement that provides, among other things, that Longnecker is engaged by, and reports only to, the Compensation Committee and will perform the compensation advisory services requested by the Compensation Committee. Longnecker does not provide any other services to the Company, and the Compensation Committee has concluded that we do not have any conflicts of interest with Longnecker.

Among the services Longnecker was asked to perform was apprising the Compensation Committee of compensation-related trends, developments in the marketplace and industry best practices; informing the Compensation Committee of compensation-related regulatory developments; providing peer group survey data to establish compensation ranges for the various elements of compensation; providing an evaluation of the competitiveness of the Company's executive and director compensation and benefits programs; assessing the relationship between executive pay and performance; and advising on the design of the Company's incentive compensation programs. Longnecker did not provide any other services to the Company during the last fiscal year.

The Compensation Committee does not adopt all recommendations given by the compensation consultant but uses the consultant's work as a reference in exercising its own judgment with respect to its own executive compensation actions and decisions. The compensation consultant regularly participates in the meetings of the Compensation Committee and meets privately with the committee at its request. Our management provides information to the consultant but does not direct or oversee its activities with respect to our executive compensation program.

The members of the Compensation Committee are Messrs. Stover (Chairman), Carr and Ogle. Messrs. Stover and Carr each joined the Compensation Committee in March 2015. Mr. Ogle joined the Compensation Committee in February 2016, replacing George DeMontrond, who served as a director in 2015 prior to his resignation in February of 2016. The Compensation Committee held six meetings during 2015.

Nominating and Governance Committee.

The Nominating and Governance Committee assists the Board of Directors in evaluating potential new members of the Board of Directors, recommending committee members and structure, and advising the Board of Directors about corporate governance practices. Additional information regarding the functions performed by the Nominating and Governance Committee is set forth in the "Corporate Governance" section included herein and also in the "Nominating and Governance Committee Charter" that is posted on the Company's website at *www.midstatespetroleum.com*.

The Nominating and Governance Committee has several methods of identifying Board candidates. First, the committee considers and evaluates whether or not the existing directors whose terms are expiring remain appropriate candidates for the Board. Second, the committee requests from time to time that its members and the other Board members identify possible candidates. Third, the committee has the authority to retain one or more search firms to aid in its search. The search firm assists the Board in identifying potential Board candidates, interviewing those candidates and conducting investigations relative to their background and qualifications.

The members of the Nominating and Governance Committee are Messrs. Stover (Chairman), Ogle and Carr. Mr. Stover joined the Nominating and Governance Committee in March 2015 and became its Chairman in February 2016, replacing Mr. Knudson. Messrs. Carr and Ogle joined the Nominating and Governance Committee in February 2016. The Nominating and Governance Committee held six meetings during 2015.

Special Committee.

The Special Committee was formed on October 8, 2015 to assist the Board of Directors in its evaluation and assessment of current market trends and conditions related to the Company's financial position and that of the Company's peers.

The members of the Special Committee are Messrs. Carr (Chairman) and Ogle. Mr. DeMontrond previously served on the Special Committee but was removed upon his resignation from the Board of Directors in February 2016. The Special Committee held one meeting during 2015.

Director Independence

The Company's standards for determining director independence require the assessment of directors' independence each year. A director cannot be considered independent unless the Board of Directors affirmatively determines that he or she does not have any relationship with management or the Company that may interfere with the exercise of his or her independent judgment, including any of the relationships that would disqualify the director from being independent under the rules of the NYSE.

The Board of Directors has assessed the independence of each non-employee director under the Company's guidelines and the independence standards of the NYSE. The Board of Directors affirmatively determined that Messrs. Stover, Ogle and Carr are independent.

Communications with the Board of Directors

Stockholders or other interested parties can contact any director (including Mr. Stover, the Chairman of the Board), any committee of the Board, or our non-management directors as a group, by writing to them c/o Corporate Secretary, Midstates Petroleum Company, Inc., 321 South Boston Avenue, Suite 1000, Tulsa, Oklahoma, 74103. Comments or complaints relating to the Company's accounting, internal controls or auditing matters will also be referred to members of the Audit Committee. All such communications will be forwarded to the appropriate member(s) of the Board.

Financial Literacy of Audit Committee and Designation of Financial Experts

The Board of Directors evaluated each of the members of the Audit Committee for financial literacy and the attributes of a financial expert in February 2015. The Board of Directors determined that each of the Audit Committee members is financially literate and that Mr. Ogle is an audit committee financial expert as defined by the SEC.

Hedging Policy

Because the Company believes that it is improper and inappropriate for its directors or executive officers to engage in short-term or speculative transactions involving the Company's securities, the Company's insider trading policy prohibits any of its directors or executive officers from engaging in hedging transactions or other transactions involving any derivative securities of the Company.

Section 16(A) Beneficial Ownership Reporting Compliance

The executive officers and directors of the Company and persons who own more than 10% of the Company's Common Stock are required to file reports with the SEC, disclosing the amount and nature of their beneficial ownership in Common Stock, as well as changes in that ownership. Based solely on its review of reports and written representations that the Company has received, the Company believes that all required reports were timely filed during 2015.

Audit Committee Report

The Board of Directors has determined that all current Audit Committee members are (i) independent, as defined in Section 10A of the Exchange Act, (ii) independent under the standards set forth by the NYSE and (iii) financially literate. In addition, Mr. Ogle qualifies as an audit committee financial expert under the applicable rules promulgated pursuant to the Exchange Act. The Audit Committee is a separately designated standing committee of the Board established in accordance with Section 3(a)(58)(A) of the Exchange Act and operates under a written charter initially approved by the Board on April 19, 2012, which is reviewed annually.

Management is responsible for our system of internal controls and the financial reporting process. The Audit Committee is responsible for monitoring (i) the integrity of our financial statements, (ii) our compliance with legal and regulatory requirements, and (iii) the independence and performance of our auditors.

The Audit Committee has reviewed and discussed with our management and the independent accountants the audited consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2015, including a discussion of the quality, not just the acceptability, of the accounting principles applied, the reasonableness of significant judgments and the clarity of disclosures in the consolidated financial statements. Management represented to the Audit Committee that our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States of America. The Audit Committee discussed with the independent accountants matters required to be discussed by Statement of Auditing Standards No. 16, Communications with Audit Committees.

Our independent accountants also provided to the Audit Committee the written disclosures required by the Public Company Accounting Oversight Board regarding independent accountant's communications with the Audit Committee concerning independence. The Audit Committee discussed with the independent accountants that firm's independence.

Based on the Audit Committee's discussions with management and the independent accountants, and the Audit Committee's review of the representations of management and the report of the independent accountants to the Audit Committee, the Audit Committee recommended that the Board include the audited consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2015 filed with the SEC.

Audit Committee of the Board of Directors
Robert E. Ogle, Chairman
Bruce Stover, Member
Alan J. Carr, Member

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

This compensation discussion and analysis, or CD&A, provides information about our compensation objectives and policies for (i) any individual who served as our Chief Executive Officer or our Chief Financial Officer during 2015, (ii) our three other most highly compensated executive officers, and (iii) any former executive officer who would have been one of our three most highly-compensated executive officers during 2015 but for the fact the executive was no longer providing services to us at the end of 2015 or is no longer employed by the Company as of the date of this filing. We refer to the aforementioned individuals throughout this discussion as the "Named Executive Officers" and their names, titles and positions are as follows:

Name	Title and Position
Frederic F. Brace	Interim President and Chief Executive Officer and Director
Dr. Peter J. Hill	Former Interim President and Chief Executive Officer
Nelson M. Haight	Executive Vice President, Chief Financial Officer and Chief Accounting Officer
Mark E. Eck	Former Executive Vice President and Chief Operating Officer
Mitchell G. Elkins	Executive Vice President—Operations
Kelly L. Walker	Former Vice President—Human Resources

On March 4, 2015, Dr. Hill notified the Board of his intent to resign from his current position as interim President and Chief Executive Officer following the filing of the Company's annual report on Form 10-K, and subsequently resigned from this position on March 18, 2015. Furthermore, Dr. Hill resigned from the Board effective as of March 9, 2015. On March 18, 2015, Frederic (Jake) F. Brace was appointed as our new Interim President and Chief Executive Officer. On December 10, 2015, Mr. Eck notified the Board of his intent to resign from his position of Executive Vice President and Chief Operating Officer and subsequently resigned from his position on January 4, 2016. On December 1, 2015, Ms. Walker notified the Board of her intent to resign from her position of Vice-President of Human Resources and subsequently resigned her position on January 4, 2016.

This CD&A focuses primarily on the information in the tables below and related footnotes, as well as the supplemental narratives, relating to the fiscal year ended December 31, 2015.

Compensation Program Philosophy and Objectives

Our future success and the ability to create long-term value for our stockholders depends on our ability to attract, retain and motivate highly qualified individuals in the oil and gas industry. Our compensation program is designed to reward performance that supports our operations and the achievement of our goals. We believe that compensation should:

- help to attract and retain highly qualified individuals in the oil and gas industry by being competitive with compensation paid to persons having similar responsibilities and duties in other companies in the same and closely related industries;
- align the interests of the individual with those of our stockholders;
- be directly tied to the attainment of annual performance targets and reflect the Named Executive Officer's individual contribution thereto;
- pay for performance, whereby an individual's total direct compensation is heavily influenced by the individuals impact to company performance; and
- reflect the unique qualifications, skills, experience and responsibilities of each individual.

Setting Executive Officer Compensation

Our Compensation Committee makes all compensation decisions related to our Named Executive Officers. For each fiscal year, our Chief Executive Officer reviews our Named Executive Officers' current compensation and makes a recommendation to our Compensation Committee regarding overall compensation structure and individual compensation levels for each Named Executive Officer other than himself.

As discussed in greater detail throughout this CD&A, our Compensation Committee met numerous times during 2015 to review and discuss executive compensation matters with respect to 2015. Our Compensation Committee intends to set each of our Named Executive Officer's base salary compensation at approximately the 50^{th} percentile within our peer group and to provide our Named Executive Officers with an opportunity to earn compensation up to approximately the 75^{th} percentile for total direct compensation, subject to target performance metrics being met or exceeded. Although our Compensation Committee reviews survey information as a frame of reference, ultimately the compensation decisions take into consideration, in material part, factors such as a particular Named Executive Officer's contribution to our financial performance and condition, as well as such officer's qualifications, skills, experience and responsibilities. Our Compensation Committee considers outside factors as well, such as shortages in the industry of qualified employees for such positions, recent experience in the marketplace, and the elapsed time between the surveys used and when compensation decisions are made. In light of these qualitative and other considerations, the base salary of a particular officer may be greater or less than the 50th percentile of our peers and total direct compensation may be greater or less than the 75th percentile of our peers and, if lower than these levels, our Compensation Committee recognizes that the compensation of certain of our executive officers may continue to build to these levels.

Benchmarking and Peer Group. For 2015, our Compensation Committee met with members of our management team and representatives from Longnecker, our compensation consultant, to select a group of companies as a "peer group" for executive and director compensation analysis purposes. This peer group was then used for purposes of developing the recommendations presented to our Board of Directors for 2015 compensation packages for our executive officers and our non-employee directors that receive compensation. The oil and gas companies that comprise this peer group were selected primarily because they (i) have similar annual revenue, assets, market capitalization and enterprise value as us and (ii) potentially compete with us for executive-level talent. In light of these considerations, it was determined that certain changes to the 2014 peer group were necessary in order to establish an appropriate peer group for 2015 to reflect changes in the Company's annual revenue, assets, market capitalization and enterprise value.

The 2015 peer group for compensation purposes consists of:

- Approach Resources, Inc.
- Bonanza Creek Energy, Inc.
- Comstock Resources, Inc.
- Goodrich Petroleum Corp.
- Halcon Resources Corporation
- Jones Energy, Inc.
- Magnum Hunter Resources Corp.
- PDC Energy, Inc.
- Penn Virginia Corporation
- Sanchez Energy Corporation
- Stone Energy Corp.
- Swift Energy Co.

Longnecker compiled compensation data for the peer group from a variety of sources, including proxy statements and other publicly filed documents. Longnecker also provided published survey compensation data from multiple sources. This compensation data was then used to compare the compensation of our Named Executive Officers to individuals with comparable duties and responsibilities at companies within our peer group and in the survey data.

For subsequent years, our Compensation Committee will review and re-determine on an annual basis the composition of our peer group so that the peer group will continue to consist of appropriate peer companies, taking into account the factors previously mentioned.

Role of the Compensation Consultant. Our Compensation Committee's charter grants the Committee the sole authority to retain, at our expense, outside consultants or experts to assist it in its duties. For 2015, our Compensation Committee engaged Longnecker to advise it with respect to executive compensation matters, including development of the annual compensation peer group and an annual review and evaluation of our executive and director compensation packages generally, based on, among other things, survey data and information regarding general trends. Representatives from Longnecker periodically meet with our Compensation Committee throughout the year and advise our Compensation Committee with regard to general trends in director and executive compensation, including (i) competitive benchmarking; (ii) incentive plan design; (iii) peer group selection; and (iv) other matters relating to executive compensation. In addition, Longnecker provides our Compensation Committee and management with survey compensation data regarding our compensation peer group for each fiscal year. Longnecker did not provide any services to us or to management other than the services provided to the Compensation Committee. As discussed above under "Meetings and Committees of Directors—Compensation Committee," the Compensation Committee has concluded that we do not have any conflicts of interest with Longnecker.

Elements of Our Compensation and Why We Pay Each Element

The compensation program for our Named Executive Officers is comprised of the following five elements:

- base salary;
- annual performance-based cash incentive awards;
- long-term equity-based compensation (including restricted stock awards);
- retention awards; and
- other employee benefits.

Base Salary. Base salary is the fixed annual compensation we pay to each Named Executive Officer for performing specific job responsibilities. It represents the minimum income a Named Executive Officer may receive in any year. We pay each Named Executive Officer a base salary in order to:

- recognize each executive officer's unique value and contributions to our success in light of salary norms in the industry and the general marketplace;
- remain competitive for executive-level talent within our industry;
- provide executives with sufficient, regularly-paid income; and
- reflect position and level of responsibility.

In setting annual base salary amounts, our Compensation Committee aims to pay base salaries that, by position, are in approximately the 50^{th} percentile of our peer group, although the Compensation Committee also takes into consideration factors such as the particular officer's contribution to our financial performance and condition, as well as the officer's qualifications, skills, experience and responsibilities.

At its February 2015 meeting, our Compensation Committee reviewed data provided by Longnecker with respect to our 2015 compensation peer group and approved increases to the base salaries of certain of our Named Executive Officers for fiscal year 2015. These increases were primarily implemented so that the base salaries of our Named Executive Officers would more closely align with the 50th percentile of our 2015 compensation peer group. The 2015 base salaries of our Named Executive Officers were set as follows:

	2015 Base Salary(1)
Frederic F. Brace	$1,200,000
Dr. Peter J. Hill	$1,200,000
Nelson M. Haight	$375,000
Mark E. Eck	$400,000
Mitchell G. Elkins	$325,000
Kelly L. Walker	$270,000

(1) Base salaries for each of the Named Executive Officers listed in the table above, prior to the modification by our Compensation Committee, were as follows: $300,000 for Mr. Haight, $225,000 for Ms. Walker. The base salaries enumerated in the table above were effective January 1, 2015 for Mr. Haight, Mr. Eck, and Ms. Walker, except with respect to Mr. Brace, who was hired in March, 2015. Mr. Elkins, whose base salary was also effective on January 1, 2015 to correspond with his promotion, received an additional increase effective September 1, 2015 to $400,000.

Additionally, in connection with Mr. Brace's appointment as Interim President and Chief Executive Officer on March 18, 2015, the Compensation Committee reviewed data provided by Longnecker with respect to the compensation of interim chief executive officers of similarly situated companies and approved cash compensation of $100,000 per month to Mr. Brace for assuming the role. During 2015, Mr. Brace participated in the Company's annual performance-based cash incentive bonus program but did not receive any equity grants under the LTIP related to his service as Interim President and Chief Executive Officer.

Annual Performance-Based Cash Incentive Awards. We have historically utilized, and expect to continue to utilize, performance-based annual cash incentive awards to reward achievement of specified performance goals for the Company as a whole with a time horizon of one year or less. We include an annual performance-based cash incentive award as part of our compensation program because we believe this element of compensation helps to:

- motivate management to achieve key annual corporate objectives, and
- align executives' interests with our goals.

Amounts paid under the performance-based annual cash incentive program are paid in the Compensation Committee's sole discretion. The Compensation Committee takes into account several quantitative and qualitative factors, including the achievement of pre-established goals or metrics, which we call "Key Performance Indicators," or "KPIs," when determining the amount of payment awarded to each Named Executive Officer. At the beginning of each year, our Chief Executive Officer develops a proposal for the annual performance metrics for that year. The Chief Executive Officer then presents his proposal to the Compensation Committee, which independently analyzes the proposed annual performance metrics, makes modifications as it sees fit, and then approves a final set of performance metrics for the year. The performance metrics are then presented to the Named Executive Officers and other members of senior management so that they fully understand the program and the goals for that particular year. In the event that the Company makes a material acquisition during the course of the year, the performance metrics may be adjusted by the Compensation Committee, in its discretion, to appropriately address any changes in the asset makeup of the Company post-acquisition.

Under our annual bonus program, our performance goals serve less as a formula and more as guidelines for our Compensation Committee to utilize throughout the year to ensure that payment of compensation under the program is aligned with the achievement of our Company's goals and targets. The performance goals are only one factor utilized by our Compensation Committee when determining actual amounts of awards. Our Compensation Committee considers a number of other subjective factors and retains the ability to apply discretion to awards based on factors such as extenuating market circumstances or individual performance and to modify amounts based on safety performance.

If we achieve the target performance metric, the cash incentive awards are expected to be paid at target levels. In order to create additional incentive for exceptional company performance based on the metrics described above and the discretion of our Compensation Committee, awards can be paid up to a maximum percentage of the base salary designated for each Named Executive Officer, but it is not expected that payment at this level would occur in most years. We set threshold, target and maximum levels for the performance metrics to serve as a guideline for determining the actual bonus amounts earned by our Named Executive Officers for 2015. In setting the performance incentive metrics for 2015, our Compensation Committee considered the extent to which targets were met in prior years to ensure that the targets utilized were sufficiently challenging. In February 2015, the Compensation Committee established the target, threshold and maximum awards to our Named Executive Officers, as a percentage of base salary, as set out in the table below. Actual award amounts are dependent on performance relative to specified performance metrics and subject to the discretion of our Compensation Committee.

	Threshold Award (as a % of base salary)	**Target Award (as a % of base salary)**	**Maximum Award (as a % of base salary)**
Frederic F. Brace	50%	100%	200%
Dr. Peter J. Hill	50%	100%	200%
Nelson M. Haight	40%	80%	160%
Mark E. Eck	40%	80%	160%
Mitchell G. Elkins	40%	80%	160%
Kelly L. Walker	30%	60%	130%

In 2015, the Compensation Committee established six KPIs, in addition to an overall adjustment for safety and environmental performance that could increase bonuses awarded under the Bonus Plan by up to 25% in the event of extraordinary performance in that area or decrease the bonuses awarded under the Bonus Plan by up to 100% in the event of severe underperformance. The specific goals set by the Compensation Committee at the beginning of 2015 and the weight given to each are listed below.

2015 Annual Performance-Based Bonus Plan

Key Performance Indicators	% of Bonus Target	Minimum Performance for Payout	Target Performance	Maximum Performance Payout
Production Volumes (Boe/d)	20%	30,000	32,000	34,000
Development Program IRR(%)	20%	23%	30%	37%
Reserve Replacement Cost ($/Boe)	10%	$33.00	$29.00	$24.00
Lease Operating Expense ($/Boe)	10%	$7.70	$6.75	$5.70
G&A Expense (cash) $mm	5%	$41	$39	$37
Fund Liquidity Gap	35%			
Safety, Health & Environmental Performance	Overall consideration of performance in these areas, which may increase or decrease total bonus amount			

Actual performance for each KPI for the fiscal year is measured and reviewed by the Compensation Committee during the first few months following the end of the fiscal year for which the annual bonus is earned. As noted above, while the Compensation Committee closely examines company and individual performance with respect to each KPI, the Compensation Committee retains the discretion to increase or decrease a Named Executive Officer’s annual cash bonus despite KPI performance based on an overall qualitative assessment of the individual officer’s performance.

In February 2016, the Compensation Committee reviewed 2015 actual performance against each of the KPIs. The Company achieved (i) between the target and maximum performance for payout under the Production Volumes metric, (ii) between the target and maximum under the Development Program Internal Rate of Return metric, (iii) above maximum performance under the Reserve Replacement Cost metric, (iv) between the target and maximum performance under the Lease Operating Expense metric, (v), above maximum performance under the G&A Expense metric, and (vi) above maximum performance under the Fund Liquidity Gap metric, which was established to focus primarily upon maintaining financial flexibility and improvement of debt metrics. The Compensation Committee did not increase or decrease the payout under the 2015 Bonus Plan for safety and environmental performance.

Overall, the formulaic outcome based on the above KPI payouts called for a total payout under the 2015 Bonus Plan of approximately 100% of the target level. The Compensation Committee granted the Named Executive Officers awards in the following amounts, which are included in the “Non-Equity Incentive Plan Compensation” column of the “Summary Compensation Table” for 2015: Mr. Brace—$1,362,598; Mr. Haight—$420,126; Mr. Eck—$407,360; and Mr. Elkins—$338,618. Our employment relationship with Dr. Hill, Mr. Eck and Ms. Walker terminated prior to the payment of the 2015 annual bonus. Dr. Hill did not receive payment of his 2015 annual bonus. Pursuant to the terms of their individual separation agreements with the Company, Mr. Eck and Ms. Walker received their respective annual bonus payments for 2015.

Long-Term Equity-Based Incentives. We believe a formal long-term equity incentive program is a valuable compensation tool and is consistent with the compensation programs of the companies in our peer group. We maintain a Long-Term Incentive Plan, or LTIP, which permits the grant of our stock, options, restricted stock, restricted stock units, phantom stock, stock appreciation rights and other awards, any of which may be designated as performance awards or be made subject to other conditions. We believe that long-term equity-based incentive compensation is an important component of our overall compensation program because it:

- balances short and long-term objectives;
- rewards long-term performance relative to industry peers;
- makes our compensation program competitive from a total remuneration standpoint;
- encourages executive retention.

Our Compensation Committee has the authority under the LTIP to award incentive equity compensation to our executive officers in such amounts and on such terms as the Committee determines appropriate in its sole discretion. To date, our long-term equity-based incentive compensation program has consisted solely of restricted stock awards. The Compensation Committee may determine in the future that different and/or additional award types are appropriate.

For 2015, our Compensation Committee made annual awards of restricted stock to our Named Executive Officers with an aggregate value at the time of grant equal to a specified percentage of the individual's base salary for the year.

Loyalty and Retention Awards. On December 18, 2014, the Compensation Committee approved the award of cash and equity retention awards to Mr. Haight and Ms. Walker. The cash retention award granted to Mr. Haight was in the amount of $750,000, and the cash retention award granted to Ms. Walker was in the amount of $405,000. The awards were paid out in three equal installments on each of January 1, 2015, June 1, 2015, and December 1, 2015, and required that the executive remained continuously employed (and not provide notice of intent to terminate employment) through each such date.

On June 6, 2014, the Compensation Committee approved the award of cash and equity retention awards to Mr. Haight, Mr. Elkins and Ms. Walker. The cash retention award granted for Mr. Haight was in the amount of $90,000 and was designed to pay out in three equal installments on each of July 1, 2014, January 2, 2015 and July 1, 2015, provided that the executive remained continuously employed (and not provide notice of intent to terminate employment) through each such date. The cash retention award granted for Mr. Elkins was in the amount of $130,000 and was designed to pay out in three installments as follows, $30,000 on July 1, 2014, $50,000 on January 2, 2015 and $50,000 on July 1, 2015, provided that the executive remains continuously employed (and not provide notice of intent to terminate employment) through each such date. The cash retention award granted for Ms. Walker was in the amount of $67,500 and was designed to pay out in three equal installments on each of July 1, 2014, January 2, 2015 and on July 1, 2015, provided that the executive remained continuously employed (and not provide notice of intent to terminate employment) through each such date. Additionally, at the February 2015 Compensation Committee Meeting, Mr. Elkins was awarded an additional retention award in the amount of $325,000 which was designed to pay out in three equal installments on each of June 1, 2015, January 1, 2016 and June 1, 2016. The executives may be eligible to receive payment of the cash loyalty and equity retention awards in connection with a termination of employment by us without cause or by the executive for good reason.

Other Employee Benefits. All of our full-time employees, including our Named Executive Officers, receive the same health and welfare benefits. The benefits include a 401(k) retirement program with a company match of up to 8% of base salary, health insurance, dental insurance, life and accidental death and dismemberment insurance, as well as long term disability insurance. We do not currently offer any other retirement or pension program as we feel that the compensation package offered to our Named Executive Officers provides compensation and incentives sufficient to attract and retain excellent talent without the addition of this benefit.

Employment Agreements

Named Executive Officer Employment Agreements

We have entered into employment agreements with certain of our executive officers ("Employment Agreements"). The initial term of the Employment Agreements is two years with automatic extensions for additional one-year periods unless either party provides at least sixty days advance written notice of the intent to terminate the Employment Agreement. Each executive is entitled to four weeks of vacation each year during the term of the Employment Agreement. The Employment Agreement contains a confidentiality obligation on the part of the executive of indefinite duration and non-competition and non-solicitation obligations on the part of the executive for a period of one-year following his termination of employment with us for any reason other than death or disability.

Upon a termination of the executive's employment by us for Cause, by the executive without Good Reason, or due to death or disability during the term of the Employment Agreement, the executive is entitled to: (i) the portion of the executive's base salary accrued through the termination to the extent not previously paid, any expense reimbursement accrued and unpaid, any employee benefits pursuant to the terms of the applicable employee benefit plan, and any accrued but unused vacation (the "Accrued Obligations"), and (ii) any accrued or vested amount arising from the executive's participation in, or benefits under, any incentive plans (the "Accrued Incentives"), which amounts are payable in accordance with the terms and conditions of such incentive plans.

Upon a termination of the executive's employment by us without Cause or by the executive for Good Reason during the term of the Employment Agreement, the executive is entitled to: (i) the Accrued Obligations, (ii) the Accrued Incentives, (iii) a lump-sum cash payment equal to the average annual bonus paid to the executive for the three immediately preceding completed fiscal years, and (iv) continued payment of the executive's base salary for a period of time.

Upon a termination of the executive's employment by us without Cause or by the executive for Good Reason during the term of the Employment Agreement and within twelve months of a change in control of us, the executive is entitled to: (i) the Accrued Obligations, (ii) the Accrued Incentives, (iii) accelerated vesting for all equity or equity based awards granted under the long-term incentive plan that are not intended to be "qualified performance based compensation" within the meaning of Section 162(m) of the Internal Revenue Code (the "Code"), and (iv) a lump-sum cash payment equal to the product of (x) the highest annual bonus paid to the executive for the three immediately preceding completed fiscal years plus the highest base salary paid to the executive during the three years immediately preceding the change in control, multiplied by (y) 2.0.

For purposes of the Employment Agreement, "Cause", in all material respects, means: (i) nonperformance by the executive of his obligations and duties, (ii) commission by the executive of an act of fraud, embezzlement, misappropriation, willful misconduct or breach of fiduciary duty against us or other conduct harmful or potentially harmful to our best interest, (iii) a material breach by the executive of the non-competition, non-solicitation, or confidentiality obligations under the Employment Agreement, (iv) the executive's conviction, plea of no contest or nolo contendere, deferred adjudication or unadjudicated probation for any felony or any crime involving fraud, dishonesty, or moral turpitude or causing material harm, financial or otherwise, to us, (v) the refusal or failure of the executive to carry out, or comply with, in any material respect, any lawful directive of our Board of Directors, (vi) the executive's unlawful use (including being under the influence) or possession of illegal drugs, or (vii) the executive's willful violation of any federal, state, or local law or regulation applicable to us or our business which adversely affects us.

For purposes of the Employment Agreement, "Good Reason" means any of the following, but only if occurring without the executive's consent: (i) a material diminution in the executive's base salary, (ii) a material diminution in the executive's authority, duties, or responsibilities, (iii) the relocation of the executive's principal office to an area more than 50 miles from its location immediately prior to such relocation, or (iv) our failure to comply with any material provision of the Employment Agreement.

Severance payments made under the Employment Agreement are contingent upon the executive's execution of a valid release of claims. Further, severance payments may be stopped and any payments already made must be repaid in the event the executive violates the confidentiality, non-competition or non-solicitation provisions of the Employment Agreement.

Section 280G of the Code prevents a corporate payor from deducting certain large payments contingent upon a change in control ("parachute payments") from the corporation's gross income for federal tax purposes. In addition, Section 4999 of the Code imposes an excise tax on the recipient of an excess parachute payment equal to 20% of the amount of the excess parachute payment. In the event that Section 280G of the Code applies to any compensation payable to the executives, the Employment Agreement provides that we will either (x) reduce the payment(s) to an amount that is one dollar less than the amount that would trigger the application of Section 280G of the Code, or (y) make the full payment owed to the executive, whichever of (x) or (y) results in the best net after tax position for the executive. The Employment Agreements do not provide any obligation for us to pay a "gross-up" or make the executive whole for any excise or regular income taxes, including the excise taxes that may be due under Section 4999 of the Code.

Employment Agreement with Mr. Brace

In connection with the appointment of Mr. Brace as interim President and Chief Executive Officer, we entered into an employment agreement with Mr. Brace outlining the terms of his employment (the "Brace Employment Agreement"). The material terms of the Brace Employment Agreement are outlined below. Except as noted otherwise below, capitalized terms used but not defined shall have the same meanings as described above with respect to the Employment Agreements.

Pursuant to the Brace Employment Agreement, Mr. Brace began serving as our interim President and Chief Executive Officer for an initial term commencing on March 9, 2015 and ending on September 9, 2016, with automatic six-month term extensions following the expiration of the initial term or any subsequent six-month extension term, provided that neither party provides a notice of non-renewal at least 60 days prior to September 9, 2016 or the end of the applicable extension term. Under the Brace Employment Agreement, Mr. Brace receives a monthly base salary of $100,000, which may be increased, but not decreased, at any time at the discretion of the Board of Directors. Mr. Brace is also eligible to receive an annual cash bonus and to participate in all other bonus, incentive, retirement and similar plans applicable generally to other similarly situated employees of us. Mr. Brace's target annual cash bonus is equal to 100 percent of his annual base salary, with the maximum annual cash bonus equal to 200 percent of his annual base salary and the minimum guaranteed annual cash bonus equal to 50 percent of his annual base salary. Under the terms of the Brace Employment Agreement, Mr. Brace and/or his family, as the case may be, is also eligible to participate in other welfare benefit plans, in accordance with the terms and conditions of applicable policies as may be in effect and/or amended from time to time. Additionally, under the Brace Employment Agreement, Mr. Brace is eligible to receive other fringe benefits and limited perquisites appertaining to his position.

Upon a termination of Mr. Brace's employment by us for Cause (as defined below), by Mr. Brace without Good Reason (as defined below), or due to death or disability during the term of the Brace Employment Agreement, Mr. Brace (or, in the case of death, Mr. Brace's legal representative) will be eligible to receive the Accrued Obligations and the Accrued Incentives.

Upon a termination of Mr. Brace's employment by us without Cause or by Mr. Brace for Good Reason, in either case, during the term of the Brace Employment Agreement, Mr. Brace would receive the following: (i) the Accrued Obligations, (ii) the Accrued Incentives, (iii) a lump-sum cash payment equal to the greater of (x) the average of the annual cash bonuses paid to Mr. Brace for the period employed with us or (y) the target annual cash bonus (i.e., 100 percent of Mr. Brace's annual base salary), and (iv) the continued payment of Mr. Brace's base salary for the remainder of the term of the Brace Employment Agreement.

For purposes of the Brace Employment Agreement, "Cause", in all material respects, means: (i) nonperformance by Mr. Brace of his obligations and duties that is not cured after written notice from the Board of Directors, (ii) commission by Mr. Brace of an act of fraud, embezzlement, misappropriation, willful misconduct or breach of fiduciary duty against us or other conduct harmful or potentially harmful to our best interest, (iii) a material breach by Mr. Brace of the non-competition, non-solicitation, or confidentiality obligations under the Brace Employment Agreement that is not cured after written notice from the Board of Directors, (iv) Mr. Brace's conviction, plea of no contest or nolo contendere, deferred adjudication or unadjudicated probation for any felony or any crime involving fraud, dishonesty, or moral turpitude or causing material harm, financial or otherwise, to us, (v) the refusal or failure of Mr. Brace to carry out, or comply with, in any material respect, any lawful directive of our Board of Directors that is not cured after written notice from the Board of Directors, (vi) Mr. Brace's unlawful use (including being under the influence) or possession of illegal drugs, or (vii) Mr. Brace's willful violation of any federal, state, or local law or regulation applicable to us or our business which adversely affects us that is not cured after written notice from the Board of Directors.

For purposes of the Brace Employment Agreement, "Good Reason" means any of the following, but only if occurring without Mr. Brace's consent: (i) a material diminution in Mr. Brace's base salary or target annual cash bonus opportunity, (ii) a material diminution in Mr. Brace's authority, duties, or responsibilities, (iii) the relocation of Mr. Brace's principal office to an area more than 50 miles from its location immediately prior to such relocation, or (iv) our failure to comply with any material provision of the Brace Employment Agreement.

Severance payments made under the Brace Employment Agreement are contingent upon Mr. Brace's execution of a valid release of claims. Further, severance payments may be stopped and any payments already made must be repaid in the event Mr. Brace violates the confidentiality, non-competition or non-solicitation provisions of the Brace Employment Agreement.

In the event that Section 280G of the Code applies to any compensation payable to Mr. Brace, the Brace Employment Agreement provides that we will either (x) reduce the payment(s) to an amount that is one dollar less than the amount that would trigger the application of Section 280G of the Code, or (y) make the full payment owed to Mr. Brace, whichever of (x) or (y) results in the best net after tax position for Mr. Brace. The Brace Employment Agreement does not provide any obligation for us to pay a "gross-up" or make Mr. Brace whole for any excise or regular income taxes, including the excise taxes that may be due under Section 4999 of the Code.

Employment Agreement with Mr. Haight

In connection with the appointment of Mr. Haight as Executive Vice-President and Chief Financial Officer, we amended his employment agreement with the Company (the "Amended Haight Employment Agreement"). The material terms of the Amended Haight Employment Agreement are outlined below. Except as noted otherwise below, capitalized terms used but not defined shall have the same meanings as described above with respect to the Employment Agreements.

Pursuant to the Amended Haight Employment Agreement, Mr. Haight will serve as our Executive Vice-President, Chief Financial Officer and Chief Accounting Officer for an initial term commencing on January 6, 2014 and ending on April 24, 2014, with automatic one-year term extensions following the expiration of the initial term or any subsequent one-year extension term, provided that neither party provides a notice of non-renewal at least 60 days prior to April 25, 2014 or the end of the applicable one-year extension term. Under the Amended Haight Employment Agreement, Mr. Haight will receive a minimum annual base salary of $300,000 (current annual base salary of $375,000), which may be increased, but not decreased, at any time at the discretion of the Board of Directors. Mr. Haight is also eligible to receive an annual cash bonus and to participate in all other bonus, incentive, retirement and similar plans applicable generally to other similarly situated employees of us. Mr. Haight's target annual cash bonus is set at the discretion of the Board. His current target is equal to

80 percent of his annual base salary, with the maximum annual cash bonus equal to 160 percent of his annual base salary and the minimum annual cash bonus equal to 40 percent of his annual base salary. Under the terms of the Amended Haight Employment Agreement, Mr. Haight and/or his family, as the case may be, is also eligible to participate in other welfare benefit plans, in accordance with the terms and conditions of applicable policies as may be in effect and/or amended from time to time. Additionally, under the Amended Haight Employment Agreement, Mr. Haight is eligible to receive other fringe benefits and limited perquisites appertaining to his position.

Upon a termination of Mr. Haight's employment by us for Cause (as defined below), by Mr. Haight without Good Reason (as defined below), or due to death or disability during the term of the Amended Haight Employment Agreement, Mr. Haight (or, in the case of death, Mr. Haight's legal representative) will be eligible to receive the Accrued Obligations and the Accrued Incentives.

Upon a termination of Mr. Haight's employment by us without Cause or by Mr. Haight for Good Reason, in either case, during the term of the Amended Haight Employment Agreement, Mr. Haight would receive the following: (i) the Accrued Obligations, (ii) the Accrued Incentives, (iii) a lump-sum cash payment equal to the average of the annual cash bonuses paid to Mr. Haight for the last three years, or if Mr. Haight has not been employed at the date of termination for three years, the period employed with us and (iv) the continued payment of Mr. Haight's base salary for a period of 18 months.

For purposes of the Amended Haight Employment Agreement, "Cause", in all material respects, means: (i) nonperformance by Mr. Haight of his obligations and duties that is not cured after written notice from the Board of Directors, (ii) commission by Mr. Haight of an act of fraud, embezzlement, misappropriation, willful misconduct or breach of fiduciary duty against us or other conduct harmful or potentially harmful to our best interest, (iii) a material breach by Mr. Haight of the non-competition, non-solicitation, or confidentiality obligations under the Amended Haight Employment Agreement that is not cured after written notice from the Board of Directors, (iv) Mr. Haight's conviction, plea of no contest or nolo contendere, deferred adjudication or unadjudicated probation for any felony or any crime involving fraud, dishonesty, or moral turpitude or causing material harm, financial or otherwise, to us, (v) the refusal or failure of Mr. Haight to carry out, or comply with, in any material respect, any lawful directive of our Board of Directors that is not cured after written notice from the Board of Directors, (vi) Mr. Haight's unlawful use (including being under the influence) or possession of illegal drugs, or (vii) Mr. Haight's willful violation of any federal, state, or local law or regulation applicable to us or our business which adversely affects us that is not cured after written notice from the Board of Directors.

For purposes of the Amended Haight Employment Agreement, "Good Reason" means any of the following, but only if occurring without Mr. Haight's consent: (i) a material diminution in Mr. Haight's base salary or target annual cash bonus opportunity, (ii) a material diminution in Mr. Haight's authority, duties, or responsibilities, (iii) the relocation of Mr. Haight's principal office to an area more than 50 miles from its location immediately prior to such relocation, or (iv) our failure to comply with any material provision of the Amended Haight Employment Agreement.

Severance payments made under the Amended Haight Employment Agreement are contingent upon Mr. Haight's execution of a valid release of claims. Further, severance payments may be stopped and any payments already made must be repaid in the event Mr. Haight violates the confidentiality, non-competition or non-solicitation provisions of the Amended Haight Employment Agreement.

In the event that Section 280G of the Code applies to any compensation payable to Mr. Haight, the Amended Haight Employment Agreement provides that we will either (x) reduce the payment(s) to an amount that is one dollar less than the amount that would trigger the application of Section 280G of the Code, or (y) make the full payment owed to Mr. Haight, whichever of (x) or (y) results in the best net after tax position for Mr. Haight. The Amended Haight Employment Agreement does not provide any obligation for us to pay a "gross-up" or make Mr. Haight whole for any excise or regular income taxes, including the excise taxes that may be due under Section 4999 of the Code.

Employment Agreement with Mr. Elkins

In connection with the appointment of Mr. Elkins as Executive Vice-President of Operations, we entered into an employment agreement with Mr. Elkins outlining the terms of his employment (the "Elkins Employment Agreement"). The material terms of the Elkins Employment Agreement are outlined below. Except as noted otherwise below, capitalized terms used but not defined shall have the same meanings as described above with respect to the Employment Agreements.

Pursuant to the Elkins Employment Agreement, Mr. Elkins will serve as our Executive Vice-President of Operations for an initial term commencing on April 1, 2014 and ending on the second anniversary of such date, with automatic one-year term extensions following the expiration of the initial term or any subsequent one-year extension term, provided that neither party provides a notice of non-renewal at least 60 days prior to April 1, 2016 or the end of the applicable one-year extension term. Under the Elkins Employment Agreement, Mr. Elkins will receive a minimum annual base salary of $300,000 (current annual base salary of $325,000), which may be increased, but not decreased, at any time at the discretion of the Board of Directors. Mr. Elkins is also eligible to receive an annual cash bonus and to participate in all other bonus, incentive, retirement and similar plans applicable generally to other similarly situated employees of us. Mr. Elkins' target annual cash bonus is set at the discretion of the Board. His current target is equal to 80 percent of his annual base salary, with the maximum annual cash bonus equal to 160 percent of his annual base salary and the minimum annual cash bonus equal to 40 percent of his annual base salary. Under the terms of the Elkins Employment Agreement, Mr. Elkins and/or his family, as the case may be, is also eligible to participate in other welfare benefit plans, in accordance with the terms and conditions of applicable policies as may be in effect and/or amended from time to time. Additionally, under the Elkins Employment Agreement, Mr. Elkins is eligible to receive other fringe benefits and limited perquisites appertaining to his position.

Upon a termination of Mr. Elkins' employment by us for Cause (as defined below), by Mr. Elkins without Good Reason (as defined below), or due to death or disability during the term of the Elkins Employment Agreement, Mr. Elkins (or, in the case of death, Mr. Elkins' legal representative) will be eligible to receive the Accrued Obligations and the Accrued Incentives.

Upon a termination of Mr. Elkins' employment by us without Cause or by Mr. Elkins for Good Reason, in either case, during the term of the Elkins Employment Agreement, Mr. Elkins would receive the following: (i) the Accrued Obligations, (ii) the Accrued Incentives, (iii) a lump-sum cash payment equal to the average of the annual cash bonuses paid to Mr. Elkins for the last three years, or if Mr. Elkins has not been employed at the date of termination for three years, the period employed with us and (iv) the continued payment of Mr. Elkins' base salary for a period of 12 months.

For purposes of the Elkins Employment Agreement, "Cause", in all material respects, means: (i) nonperformance by Mr. Elkins of his obligations and duties that is not cured after written notice from the Board of Directors, (ii) commission by Mr. Elkins of an act of fraud, embezzlement, misappropriation, willful misconduct or breach of fiduciary duty against us or other conduct harmful or potentially harmful to our best interest, (iii) a material breach by Mr. Elkins of the non-competition, non-solicitation, or confidentiality obligations under the Elkins Employment Agreement that is not cured after written notice from the Board of Directors, (iv) Mr. Elkins' conviction, plea of no contest or nolo contendere, deferred adjudication or unadjudicated probation for any felony or any crime involving fraud, dishonesty, or moral turpitude or causing material harm, financial or otherwise, to us, (v) the refusal or failure of Mr. Elkins to carry out, or comply with, in any material respect, any lawful directive of our Board of Directors that is not cured after written notice from the Board of Directors, (vi) Mr. Elkins' unlawful use (including being under the influence) or possession of illegal drugs, or (vii) Mr. Elkins' willful violation of any federal, state, or local law or regulation applicable to us or our business which adversely affects us that is not cured after written notice from the Board of Directors.

For purposes of the Elkins Employment Agreement, "Good Reason" means any of the following, but only if occurring without Mr. Elkins' consent: (i) a material diminution in Mr. Elkins' base salary or target annual cash bonus opportunity, (ii) a material diminution in Mr. Elkins' authority, duties, or responsibilities, (iii) the relocation of Mr. Elkins' principal office to an area more than 50 miles from its location immediately prior to such relocation, or (iv) our failure to comply with any material provision of the Elkins Employment Agreement.

Severance payments made under the Elkins Employment Agreement are contingent upon Mr. Elkins' execution of a valid release of claims. Further, severance payments may be stopped and any payments already made must be repaid in the event Mr. Elkins violates the confidentiality, non-competition or non-solicitation provisions of the Elkins Employment Agreement.

In the event that Section 280G of the Code applies to any compensation payable to Mr. Elkins, the Elkins Employment Agreement provides that we will either (x) reduce the payment(s) to an amount that is one dollar less than the amount that would trigger the application of Section 280G of the Code, or (y) make the full payment owed to Mr. Elkins, whichever of (x) or (y) results in the best net after tax position for Mr. Elkins. The Elkins Employment Agreement does not provide any obligation for us to pay a "gross-up" or make Mr. Elkins whole for any excise or regular income taxes, including the excise taxes that may be due under Section 4999 of the Code.

Severance Arrangements

Mark E. Eck

Effective January 4, 2016, Mr. Eck resigned from employment with the Company. In connection with his resignation, Mr. Eck entered into an agreement with the Company pursuant to which Mr. Eck received a lump sum payment equivalent to his accrued 2015 short term incentive bonus, which was paid in February 2016. Pursuant to the terms of Company's 2012 Long-Term Incentive Plan, any unvested shares of restricted stock which were previously awarded to Mr. Eck expired on January 4, 2016.

Kelly L. Walker

Effective January 4, 2016, Ms. Walker resigned from employment with the Company. In connection with her resignation, Ms. Walker entered into an agreement with the Company pursuant to which Ms. Walker will receive a lump sum payment equivalent to the following: her annual base salary in the amount of $270,000; the average of her past three annual bonus payments, which was $134,313; and her accrued 2015 short term incentive bonus, in the amount of $204,719. Additionally, the vesting of all unvested shares of restricted stock held by Ms. Walker as of her separation date was accelerated, with any settlement that may be due to Ms. Walker as a result of such accelerated vesting being made pursuant to the terms of the Company's 2012 Long-Term Incentive Plan.

Accounting and Tax Considerations

Under Section 162(m) of the Internal Revenue Code a limitation is placed on tax deductions of any publicly-held corporation for individual compensation to "covered employees" (within the meaning of Section 162(m) of the Internal Revenue Code) of such corporation exceeding $1,000,000 in any taxable year, unless the compensation meets certain requirements for qualified "performance-based compensation." Newly public companies generally are not subject to the deduction limitations of Section 162(m) of the Internal Revenue Code until the first stockholder meeting that occurs after the close of the third calendar year following the calendar year in which the initial public offering occurs, or at the time of a material amendment to the plan, whichever occurs first. We became subject to the limitations and requirements of Section 162(m) as of the 2014 Annual Meeting.

To the extent possible, we seek to maintain the favorable tax treatment of compensation. We believe, however, that under some circumstances, such as to attract or retain key executives or to recognize outstanding performance, it is in the best interest of the Company to provide compensation to selected executives even if it is not fully deductible.

Section 280G of the Code prevents a corporate payor of certain types of payments made to executives in connection with a change of control from deducting portions of such payments from the corporation's gross income for federal income tax purposes, to the extent they exceed certain monetary thresholds (the excess over those thresholds is referred to as the "excess parachute payment"). In addition, Section 4999 of the Code imposes an excise tax on the recipient of these payments equal to 20% of the amount of the excess parachute payment. Some companies provide "gross-ups" to their executives to cover any excise tax that may become due under Section 4999 of the Code. The Employment Agreements do not provide any obligation for us to pay a "gross-up" or make the executive whole for any excise or regular income taxes, including any excise taxes that may be due under Section 4999 of the Code.

All equity awards to our employees, including our Named Executive Officers, and to our directors will be granted and reflected in our consolidated financial statements, based upon the applicable accounting guidance, at fair market value on the grant date in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC"), Topic 718, "Compensation—Stock Compensation."

Compensation Practices as They Relate to Risk Management

We believe our compensation programs do not encourage excessive and unnecessary risk taking by executive officers (or other employees). Our annual performance-based cash incentive program is based upon several different performance metrics that are both quantitative and qualitative. Further, because our Compensation Committee retains the ability to apply discretion when determining the actual amount to be paid to executives pursuant to our annual performance-based cash incentive program, our Compensation Committee is able to assess the actual behavior of our executives as it relates to risk taking in awarding bonus amounts. Further, our use of long-term equity-based compensation reduces any potential incentives to take unnecessary short-term risk.

COMPENSATION COMMITTEE REPORT

The Compensation Committee of the Company has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

The foregoing report is provided by the following directors, who constitute all the members of the Compensation Committee:

Members of the Compensation Committee of the Board of Directors

Bruce Stover, Chairman
Alan J. Carr, Member
Robert E. Ogle, Member

Summary Compensation Table

The following table sets forth information regarding the compensation awarded to, earned by, or paid to our Named Executive Officers during the fiscal years ended December 31, 2015, 2014, and 2013.

Name and Principal Position	Year	Salary ($)(1)	Bonus(2)	Stock Awards ($)(3)	Non-Equity Incentive Plan Compensation ($)(4)	All Other Compensation ($)(5)	Total ($)
Frederic F. Brace	2015	973,076	—	—	1,362,598	—	2,335,674
Interim President and Chief Executive Officer							
Peter J. Hill	2015	400,000	—	—	—	103,744	503,744
Former Interim President and Chief Executive Officer(6)	2014	963,625	—	115,000	750,000	—	1,828,625
Nelson M. Haight	2015	375,033	810,000	716,766	420,126	21,200	2,343,125
Executive Vice President and	2014	299,615	30,000	1,168,699	239,693	17,500	1,755,507
Chief Financial Officer	2013	220,667	—	324,830	158,000	17,500	720,997
Mark E. Eck	2015	404,615	—	—	407,360	21,200	833,175
Former Executive Vice President and Chief Operating Officer							
Mitchell G. Elkins	2015	350,000	208,333	179,828	338,618	21,200	1,097,979
Executive Vice President—Operations							
Kelly L. Walker	2015	270,000	450,000	387,058	204,719	18,000	1,329,777
Vice President—Human Resources							

(1) This column reflects the base salary earned by each Named Executive Officer during the 2015 fiscal year.

(2) These amounts represent the payment of the cash loyalty and cash retention awards for Messrs. Haight and Elkins and Ms. Walker. The cash loyalty awards were designed to pay out in equal installments on each of June 1, 2014, January 2, 2015 and July 1, 2015. The payment of the cash retention awards were designed to pay out on June 1, 2015, January 1, 2016 and June 1, 2016 for Mr. Elkins and for Mr. Haight and Ms. Walker on January 1, 2015, June 1, 2015 and December 1, 2015. For 2015, Mr. Elkins received $50,000 for each cash loyalty award, and $108,333 for the two retention award payments. For 2015, Mr. Haight received $30,000 for each cash loyalty award, and $250,000 for the three cash retention award payments. Ms. Walker received $22,500 for each cash loyalty award, and $135,000 for the three cash retention award payments.

(3) The amounts reflected in the table above for restricted stock are reported based upon the grant date fair value computed in accordance with Financial Accounting Standards Board (“FASB”) Accounting Standard Codification (“ASC”) Topic 718, excluding the effect of estimated forfeitures. See Note 11 to our consolidated financial statements on Form 10-K for the year ended December 31, 2015 for additional detail regarding assumptions underlying the value of these equity awards.

(4) The amounts reported in this column reflect the amount paid to each executive in February of 2016 with respect to performance in 2015 under our annual short term incentive bonus program. Our employment relationship with Dr. Hill terminated prior to the payment of his 2015 annual bonus.

(5) The amounts presented for Messrs. Haight and Elkins and Ms. Walker represent a company match of 401(k) contributions made in 2015. The amount presented in this column for Dr. Hill for 2015 represents his vacation payout received following his termination of employment on April 30, 2015.

(6) Dr. Hill resigned from his position as our Interim President and Chief Executive Officer in March of 2015 but continued to provide transition services to us through April 30, 2015.

Grants of Plan-Based Awards for 2015

The table sets forth the threshold, target, and maximum awards for each of our Named Executive Officers under our annual cash bonus program as well as the number of shares of restricted stock awarded during 2015 to the Company's Named Executive Officers under the LTIP.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1)			All Other Stock Awards: Number of Shares of	Grant Date Fair Value of Stock
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Stock(2)(#)**	**Awards(3)($)**
Frederic F. Brace		1,033,407	1,238,726	1,544,272		
Peter J. Hill(4)		—	—	—	—	—
Nelson M. Haight		318,628	381,933	476,141		
	1/1/2015				47,468	716,766.80
Mark E. Eck		339,840	407,360	507,840	—	—
Mitchell G. Elkins		297,360	356,440	444,360		
	3/11/2015				21,666	179,827.80
Kelly L. Walker		215,055	257,783	321,368		
	1/1/2015				25,633	387,058.30

(1) These columns reflect the threshold, target, and maximum levels established for each Named Executive Officer under our annual cash bonus program, calculated based on each Named Executive Officer's base salary in effect as of December 31, 2015 and utilizing the final threshold, target and maximum levels established by the Compensation Committee in 2015. For more information about our annual cash bonus program or the Named Executive Officer's targets levels under that program, please see the "Compensation Discussion and Analysis—Elements of our Compensation and Why we Pay Each Element—Annual Performance-Based Cash Incentive Awards" section of this Annual Report on Form 10-K.

(2) The amounts in this column represent the restricted stock granted to the Named Executive Officers on the respectively noted dates. These shares of restricted stock vest in three equal annual installments beginning one year from the date of grant. All the unvested restricted stock held by Mr. Eck was forfeited at the time of his separation from the Company.

(3) The amounts reflected in the table above for restricted stock are reported based upon the grant date fair value computed in accordance FASB ASC Topic 718, excluding the effect of estimated forfeitures. See Note 11 to our consolidated financial statements on Form 10-K for the year ended December 31, 2015 for additional detail regarding assumptions underlying the value of these equity awards.

(4) Dr. Hill resigned from his position as our Interim President and Chief Executive Officer in March of 2015 but continued to provide transition services to us through April 30, 2015.

Outstanding Equity Awards at Fiscal Year End

The following table sets forth information concerning outstanding equity awards held by each of our Named Executive Officers as of December 31, 2015.

	Option Awards				Stock Awards	
Name	Number of Securities Underlying Unexercised Options (#) Exercisable(1)	Number of Securities Underlying Unexercised Options (#) Unexercisable	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(10)
Frederic F. Brace					—	—
Peter J. Hill					—	—
Nelson M. Haight...............					834(2)	1,685
					800(3)	1,616
					3,200(4)	6,464
					8,000(5)	16,160
					3,214(6)	6,492
					47,468(8)	95,885
Mark E. Eck(11)					17,778(7)	35,912
Mitchell G. Elkins..............						
					1,434(2)	2,897
					8,000(5)	16,160
					3,214(6)	6,492
					21,666(9)	43,765
Kelly L. Walker					834(2)	1,685
					3,800(5)	7,676
					2,411(6)	4,870
					25,633(8)	51,779

(1) The number of incentive unit awards reflected in this column does not correlate to the Company's common shares because the incentive units are interests in one of our affiliates. Incentive units represent actual equity interests in us or one of our affiliates that have no value for tax purposes on the date of grant and are designed to gain value only after we or one of our affiliates has realized a certain level of growth and return to those individuals who hold certain other classes of our equity. We believe these interests are most similar economically to stock appreciation rights. The definition of "option" in the regulations governing this disclosure includes stock options, stock appreciation rights, and "similar instruments." Because we believe that incentive units are most similar to stock appreciation rights we think they are properly classified as "options" under the definition in the regulations governing this disclosure. As such, the incentive units granted to our Named Executive Officers are disclosed in the table above under the columns required by the regulations governing this disclosure for options (as defined in those regulations). The economics of incentive units are borne entirely by our investor, First Reserve Management, L.P. ("First Reserve"); however, due to the accounting treatment of the incentive units, we will record a non-cash compensation charge in the period any payment is made with respect to the incentive units. No options to purchase our stock, in the traditional sense of the term, have been granted to our Named Executive Officers.

(2) Amounts reported in this column represent time-vested restricted stock awards granted on February 21, 2013. The awards vest in one-third increments over a three-year period on the anniversary of the date of grant.

(3) Amounts reported in this column represent time-vested restricted stock awards granted on August 23, 2013. The awards vest in one-third increments over a three-year period on the anniversary of the date of grant.

(4) Amounts reported in this column represent time-vested restricted stock awards granted on January 1, 2014. The awards vest in one-third increments over a three-year period on the anniversary of the date of grant.

(5) Amounts reported in this column represent time-vested restricted stock awards granted on February 21, 2014. The awards vest in one-third increments over a three-year period on the anniversary of the date of grant.

(6) Amounts reported in this column represent time-vested restricted stock awards granted on June 6, 2014. The awards vest in one-third increments over a three-year period on the anniversary of the date of grant.

(7) Amounts reported in this column represent time-vested restricted stock awards granted on December 29, 2014. The awards vest over a one-year period on the anniversary of the date of grant.

(8) Amounts reported in this column represent time-vested restricted stock awards granted on January 1, 2015. The awards vest in one-third increments over a three-year period on the anniversary of the date of grant.

(9) Amounts reported in this column represent time-vested restricted stock awards granted on March 11, 2015. The awards vest in one-third increments over a three-year period on the anniversary of the date of grant.

(10) For purposes of calculating the amounts in this column, the closing price of our shares on the NYSE on December 31, 2015 of $2.02 was used.

(11) All the unvested restricted stock held by Mr. Eck was forfeited at the time of his separation from the Company.

Option Exercises and Stock Vested

The table below sets forth, for each Named Executive Officer, information about lapses of restrictions on restricted stock awards during the year ended December 31, 2015. Our Named Executive Officers have not been granted any stock option awards.

	Stock Awards	
Named Executive Officer	**Number of Shares Acquired on Vesting (#)**	**Value Realized on Vesting(1)($)**
Frederic F. Brace	—	—
Peter J. Hill	2,500	29,000
Nelson M. Haight	9,865	112,229
Mark E. Eck	8,888	18,487
Mitchell G. Elkins	8,642	99,781
Kelly L. Walker	4,963	57,351

(1) The value realized with respect to vesting of restricted stock awards is based on the closing price per share of the Company's Common Stock on the date of vesting of the awards.

Potential Payments Upon Termination and Change in Control

Terminations of Employment During 2016

Effective January 4, 2016, Mr. Eck resigned from employment with the Company. In connection with his resignation, Mr. Eck entered into an agreement with the Company pursuant to which Mr. Eck received a lump sum payment equivalent to his accrued 2015 short term incentive bonus, which was paid in February 2016. Pursuant to the terms of Company's 2012 Long-Term Incentive Plan, any unvested shares of restricted stock which were previously awarded to Mr. Eck expired on January 4, 2016.

Effective January 4, 2016, Ms. Walker resigned from employment with the Company. In connection with her resignation, Ms. Walker entered into an agreement with the Company pursuant to which Ms. Walker will receive a lump sum payment equivalent to the following: her annual base salary in the amount of $270,000; the average of her past three annual bonus payments which was $134,313; and her accrued 2015 short term incentive bonus, in the amount of $204,719. Additionally, the vesting of all unvested shares of restricted stock held by Ms. Walker as of her separation date, will be accelerated, with any settlement that may be due to Ms. Walker as a result of such accelerated vesting being made pursuant to the terms of the Company's 2012 Long-Term Incentive Plan.

Estimated Payments Due Pursuant to Existing Agreements

As discussed in "Compensation Discussion and Analysis—Employment Agreements," the Company maintains employment agreements with certain Named Executive Officers that provide for potential severance payments upon a termination of the executive's employment under various circumstances.

Upon a termination by us for Cause, by the executive without Good Reason, or due to the death or disability of the executive during the term of the employment agreement, each of the Named Executive Officers is entitled to (i) the Accrued Obligations and (ii) the Accrued Incentives, payable in accordance with the terms and conditions of such incentive plans.

Upon a termination of a Named Executive Officer's employment by us without Cause or by the executive for Good Reason during the term of the employment agreement, each of Named Executive Officers is entitled to: (i) the Accrued Obligations, (ii) the Accrued Incentives, (iii) a lump-sum cash payment equal to the average annual bonus paid to the executive for the three immediately preceding completed fiscal years, and (iv) continued payment of the executive's base salary for a period of 12 months for Mr. Elkins and 18 months for Mr. Haight. For Mr. Brace, his continued payment of his base salary would be for a period through the end of his term of September 9, 2016. To the extent that there remains no more term under his executive agreement, there will be no salary continuation payments.

The following table displays the value of the severance payments described in the preceding sentence for each of our Named Executive Officers, assuming that an eligible termination of employment occurred on December 31, 2015.

Named Executive Officer	Lump-Sum Payment based on Average Annual Bonus ($)	Continued Base Salary ($)	Total ($)
Frederic F. Brace	1,362,598	900,000	2,262,598
Nelson M. Haight	272,606	562,500	835,106
Mitch G. Elkins	233,539	400,000	633,539

Upon a termination of a Named Executive Officer's employment by us without Cause or by the executive for Good Reason during the term of the employment agreement and within twelve months of a change in control of us, the executive is entitled to: (i) the Accrued Obligations, (ii) the Accrued Incentives, (iii) accelerated vesting for all equity or equity based awards granted under the LTIP that are not intended to be "qualified performance based compensation" within the meaning of Section 162(m) of the Code, and (iv) a lump-sum cash payment equal to the product of (x) the highest annual bonus paid to the Named Executive Officer for the three immediately preceding completed fiscal years plus the highest base salary paid to the Named Executive Officer during the three years immediately preceding the change in control, multiplied by (y) 2 for Messrs. Haight and Elkins. For Mr. Brace, his continued payment of his base salary would be for a period through the end of his term of September 9, 2016. To the extent that there remains no more term under his executive agreement, there will be no salary continuation payments.

The following table displays the value of the severance payments described in the preceding sentence for each of our Named Executive Officers, assuming that an eligible termination of employment occurred on December 31, 2015.

Named Executive Officer	Accelerated Vesting of Awards ($)(1)	Lump-Sum Payment based on Highest Bonus and Salary ($)	Continued Base Salary ($)	Total ($)
Frederic F. Brace	—	—	900,000	900,000
Nelson M. Haight	63,516	1,590,318	—	1,653,834
Mitch G. Elkins	34,314	1,477,236	—	1,511,550

(1) The value reported above for the acceleration of unvested restricted stock is calculated based on closing market price of our common shares on December 31, 2015.

Severance payments made under the employment agreements are contingent upon the Named Executive Officer's execution of a valid release of claims. Further, severance payments may be stopped and any payments already made must be repaid in the event the Named Executive Officer violates the confidentiality, non-competition and non-solicitation provisions of their employment agreement. Our Board of Directors felt that this provision was particularly important in order to dissuade the executive from violating the confidentiality, non-competition, and non-solicitation provisions of their employment agreement and to make such provisions easier to enforce in the event of breach, thus better protecting our business interests and confidential information.

In the event that Section 280G of the Code applies to any compensation payable to the Named Executive Officers, the employment agreements provide that we will either (x) reduce the payment(s) to an amount that is one dollar less than the amount that would trigger the application of Section 280G of the Code, or (y) make the full payment owed to the Named Executive Officer, whichever of (x) or (y) results in the best net after tax position for the Named Executive Officer. The employment agreements do not provide any obligation for us to pay a "gross-up" or make the executive whole for any excise or regular income taxes, including excise taxes that may be due under Section 4999 of the Code.

Rule 10b5-1 Sales Plans

Our directors and executive officers may adopt written plans, known as Rule 10b5-1 plans, in which they will contract with a broker to buy or sell shares of our Common Stock on a periodic basis. Under a Rule 10b5-1 plan, a broker executes trades pursuant to parameters established by the director or officer when entering into the plan, without further direction from them. The director or officer may amend or terminate the plan in some circumstances. Our directors and executive officers may also buy or sell additional shares outside of a Rule 10b5-1 plan when they are not in possession of material, nonpublic information pursuant to the Company's insider trading plan.

Director Compensation

We believe that attracting and retaining qualified non-employee directors is critical to our future value growth and governance, and that providing a total compensation package between the 50th percentile and 75th percentile of our peer group is necessary to accomplish that objective.

Our Compensation Committee reviews the compensation of our non-employee directors on an annual basis. For 2015, our compensation program for our non-employee directors was as follows:

- an annual cash retainer fee of $150,000 and an additional cash retainer fee of $30,000 for the Lead Director/Chairman of the Board;
- $1,500 in cash for each Board of Directors' meeting attended, whether in person or teleconference;
- $1,500 in cash for each committee meeting attended, whether in person or teleconference;
- committee chairpersons receive the following annual cash retainers: (a) Audit Committee chair—$15,000, (b) Compensation Committee chair—$10,000, (c) Nominating & Governance Committee chair—$10,000; and (d) Special Committee chair—$10,000;
- committee members receive the following annual cash retainers: (a) Audit Committee member—$7,500, (b) Compensation Committee member—$5,000, (c) Nominating & Governance Committee member—$5,000; and (d) Special Committee member—$5,000.

Additional quarterly and/or per meeting payments may also be made to the extent any directors are asked to serve on any additional special committees. Directors who are also our employees do not receive any additional compensation for their service on our Board of Directors. In 2015, Dr. Hill and Mr. Brace were the only directors of the Company who were also employees of the Company, however, Dr. Hill did receive additional compensation for his servce on our Board of Directors.. Directors who are employees of First Reserve or Riverstone Holdings or their affiliates do not receive any additional compensation from us for their service on our Board of Directors and have entered into other compensation arrangements with First Reserve or Riverstone, respectively, for the services they provide to us on behalf of those entities. During 2015, John Mogford, George DeMontrond, and Robert Tichio were each employed with (or provided consulting services to) either First Reserve or Riverstone and, as such, received no compensation from us for their service on our Board of Directors.

Each director is reimbursed for travel and miscellaneous expenses (i) to attend meetings and activities of our Board of Directors or its committees; and (ii) related to such director's participation in our general education and orientation program for directors.

The following table provides information concerning the compensation of our non-employee directors for the fiscal year ended December 31, 2015.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)	Total ($)
Mary P. Ricciardello(2)	57,000	—	57,000
Thomas C. Knudson(2)	208,520	—	208,520
Robert E. Ogle	146,250	—	146,250
Loren M. Leiker(2)	55,250	—	55,250
Alan J. Carr	148,875	—	148,875
Bruce Stover	159,375	—	159,375
Peter J. Hill(2)	14,000	—	14,000
Stephen J. McDaniel(2)	14,000	—	14,000

(1) Includes annual cash retainer fee, board and committee meeting fees, and committee chair and member fees for each non-employee director during fiscal year 2015 as more fully explained in the preceding paragraphs.

(2) Individual served as a director during the fiscal year ended December 31, 2015 but is not a current director as of March 23, 2016.

Compensation Committee Interlocks and Insider Participation

During 2015, no member of the Compensation Committee served as an executive officer of the Company. During 2015, there were no Compensation Committee interlocks with other companies.

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

The following table sets forth certain information regarding the beneficial ownership of Common Stock as of March 28, 2016 by (i) each person who is known by the Company to own beneficially more than five percent of the outstanding shares of Common Stock, (ii) each Named Executive Officer of the Company, (iii) each director of the Company and (iv) all directors and executive officers as a group. Unless otherwise noted, the mailing address of each person or entity named below is 321 South Boston Avenue, Suite 1000, Tulsa, Oklahoma 74103.

As of March 28, 2016, 10,798,029 shares of our Common Stock were outstanding.

Name of Person or Identity of Group	Number of Shares	Percentage of Class
5% Shareholders:		
FR Midstates Interholding, LP(1)	2,714,765	25.1%
R/C IV Eagle Holdings, L.P.(2)	1,960,265	18.2%
Directors, Director Nominees and Named Executive Officers:		
Frederic F. Brace	—	—
Alan J. Carr	—	—
Bruce Stover	—	—
Robert E. Ogle	—	—
Nelson M. Haight	57,276	*
Mark E. Eck	26,666	*
Mitchell G. Elkins	45,098	*
Scott C. Weatherholt	12,000	*
Dr. Peter J. Hill	4,100	*
All directors and executive officers as a group (7 persons)	114,374	1.1%

* Less than 1%.

(1) FR Midstates Interholding, L.P.'s general partner is FR XII Alternative GP, L.L.C. FR XII Alternative GP, L.L.C.'s managing member is First Reserve GP XII, L.P. The general partner of First Reserve GP XII, L.P. is First Reserve GP XII Limited. William E. Macaulay is a director of First Reserve GP XII Limited and has the right to appoint the majority of the board of directors of First Reserve GP XII Limited. The address of each of FR Midstates Interholding, L.P., FR XII Alternative GP, L.L.C., First Reserve GP XII, L.P., First Reserve GP XII Limited and William E. Macaulay is One Lafayette Place, Greenwich, Connecticut 06830.

(2) Based on a Schedule 13D/A filed with the SEC on February 4, 2016 by R/C IV Eagle Holdings, L.P., Riverstone/Carlyle Energy Partners IV, L.P. and R/C Energy GP IV, LLC, each of R/C IV Eagle Holdings, L.P., Riverstone/Carlyle Energy Partners IV, L.P. and R/C Energy GP IV, LLC may be deemed to beneficially own 1,960,265 shares of Common Stock. The address of each of R/C IV Eagle Holdings, L.P., Riverstone/Carlyle Energy Partners IV, L.P. and R/C Energy GP IV, LLC is 712 Fifth Avenue, 36th Floor, New York, NY 10019.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Procedures for Review, Approval and Ratification of Related Person Transactions

A "Related Party Transaction" is a transaction, arrangement or relationship in which the Company or any of its subsidiaries was, is or will be a participant, the amount of which involved exceeds $120,000, and in which any related person had, has or will have a direct or indirect material interest. A "Related Person" means:

- any person who is, or at any time during the applicable period was, one of the Company's executive officers or one of its directors;
- any person who is known by the Company to be the beneficial owner of more than 5% of the Company's Common Stock;
- any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law or sister-in-law of a director, executive officer or a beneficial owner of more than 5% of the Company's Common Stock, and any person (other than a tenant or employee) sharing the household of such director, executive officer or beneficial owner of more than 5% of the Company's Common Stock; and
- any firm, corporation or other entity in which any of the foregoing persons is a partner or principal or in a similar position or in which such person has a 10% or greater beneficial ownership interest.

The Board of Directors has determined that the Audit Committee will periodically review all related person transactions that the rules of the SEC require be disclosed and make a determination regarding the initial authorization or ratification of any such transaction.

The Audit Committee is charged with reviewing the material facts of all related person transactions and either approving or disapproving of the Company's participation in such transactions under the Company's written Related Persons Transaction Policy adopted by the Board of Directors at the time of our initial public offering in April 2012, which pre-approves or ratifies (as applicable) certain related person transactions, including:

- any employment of an executive officer if his or her compensation is required to be disclosed under Item 402;
- director compensation that is required to be disclosed under Item 402;
- any transaction with another company at which a Related Person's only relationship is as an employee (other than an executive officer), director or beneficial owner of less than 10% of that company's shares if the aggregate amount involved for any particular service does not exceed the greater of $500,000 or 25% of that company's total annual revenues; and
- charitable contribution, grant or endowment by the Company to a charitable organization, foundation or university at which a Related Person's only relationship is as an employee (other than an executive officer) or a director if the aggregate amount involved does not exceed the lesser of $200,000 or 10% of the charitable organization's total annual receipts.

In determining whether to approve or disapprove entry into a Related Party Transaction, the Audit Committee shall take into account, among other factors, the following: (i) whether the Related Party Transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances and (ii) the extent of the Related Person's interest in the transaction. Further, the policy requires that all Related Party Transactions required to be disclosed in the Company's filings with the SEC be so disclosed in accordance with applicable laws, rules and regulations.

There were no related persons transactions since January 1, 2015 which were required to be reported in "Transactions with Related Persons," where the procedures described above did not require review, approval or ratification or where these procedures were not followed. In addition, since January 1, 2015, there has not been any transaction or series of similar transactions to which the Company was or is a party in which the amount involved exceeded or exceeds $120,000 and in which any of the Company's directors, executive officers, holders of more than 5% of any class of its voting securities, or any member of the immediate family of any of the foregoing persons, had or will have a direct or indirect material interest, other than compensation arrangements with directors and executive officers, which are described in "Executive Compensation and Other Information," and the transactions described or referred to below.

Stockholders’ Agreement

In connection with the closing of our initial public offering, we entered into a stockholders’ agreement (the “Stockholders’ Agreement”) with FRMI, Stephen J. McDaniel (former director and Chairman of the Board), and certain of our executive officers and other members of our management team. The Stockholders’ Agreement contains several provisions relating to the sale of our Common Stock by the parties thereto, a summary of which is set forth below.

The Stockholders’ Agreement grants FRMI the right to nominate three members of our Board of Directors so long as FRMI holds at least 25% of our outstanding shares of Common Stock. Upon the identification by our Board of Directors of an additional director nominee that our Board of Directors has affirmatively determined is independent pursuant to the listing standards of the NYSE and Rule 10A-3 of the Exchange Act, FRMI has agreed to cause one of its director nominees to resign if so requested by the Board. At and as of such time that FRMI holds less than 25% of our outstanding shares of Common Stock, FRMI will have the right to nominate one member of our Board of Directors. The Stockholders’ Agreement also requires the stockholders party thereto to take all necessary actions, including voting their shares of Common Stock, for the election of the FRMI nominees and the Board’s other nominees.

Eagle Registration Rights Agreement

On October 1, 2012, in connection with the closing of the Company’s acquisition of the assets of Eagle Energy Production, LLC (“Eagle”), the Company, Eagle, FRMI and certain of our other stockholders entered into a Registration Rights Agreement (the “Eagle Registration Rights Agreement”), pursuant to which the Company has agreed to register the sale of shares of our Common Stock under the circumstances described below. The provisions relating to registration rights in the Eagle Registration Right Agreement supersede the provisions relating to registration rights contained in the Stockholders’ Agreement that previously applied to FRMI only.

At any time after the conversion of the Preferred Stock into Common Stock (with respect to Eagle) or October 25, 2012 (with respect to FRMI), Eagle or FRMI, as applicable, has the right to require us by written notice to register the sale of any number of their shares of Common Stock. We are required to provide notice of the demand request within 30 days following receipt of such demand request to all stockholders party to the Eagle Registration Rights Agreement to allow for inclusion of such other stockholders’ Common Stock. Eagle and FRMI each have the right to cause up to an aggregate of six such demand registrations. In no event shall more than one demand registration occur within six months after the effective date of a registration statement filed pursuant to a demand request or within 60 days prior to our good faith estimate of the date of an offering and 180 days after the effective date of a registration statement we file.

If, at any time, we propose to register an offering of Common Stock (subject to certain exceptions) for our own account, then we must give prompt notice (subject to reduction to one business day’s notice in connection with certain offerings) to all stockholders party to the Eagle Registration Rights Agreement to allow them to include a specified number of their shares in that registration statement.

These registration rights are subject to certain conditions and limitations, including the right of underwriters to limit the number of shares to be included in a registration and our right to delay or withdraw a registration statement under certain circumstances. The obligations to register shares under the Eagle Registration Rights Agreement will terminate when no registrable shares (as defined in the Eagle Registration Rights Agreement) remain outstanding.

Transactions with Related Persons

Throughout 2015, the Company has contracted with Elkins Drilling Solutions, LLC to provide services for drilling operations in the Mississippian Lime basin. Elkins Drilling Solutions, LLC is a limited liability company of which the president, Chris Elkins, is the son of Mitch Elkins, Executive Vice President of Operations of the Company. For the fiscal year 2015, the Company paid $319,245 to Elkins Drilling Solutions, LLC for contracted services. The Audit Committee reviewed and approved the Company’s participation in these transactions, pursuant to the process described above.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The firm of Deloitte and Touche LLP is our independent registered public accounting firm. The following table sets forth fees paid to Deloitte and Touche LLP during the years ended December 31, 2015 and 2014.

	2015	2014
Audit fees(1)	$1,715,565	$1,052,347
Audit-related fees(2)	—	9,625
Tax fees(3)	168,119	140,060
All other fees	—	—
Total	$1,883,684	$1,202,032

(1) Audit fees consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with GAAP.

(2) Audit-related fees include fees related to acquisition due diligence and accounting consultations.

(3) Tax fees consist primarily of services rendered for tax compliance, tax advice and tax planning.

The charter of the Audit Committee provides that the committee is responsible for the pre-approval of all auditing services and permitted non-audit services to be performed for us by our independent registered public accounting firm, subject to the requirements of applicable law. In accordance with such charter, the Audit Committee may delegate the authority to grant such pre-approvals to the Audit Committee chairman, whicnh pre-approvals are then reviewed by the full Audit Committee at its next regular meeting. Typically, however, the Audit Committee itself reviews the matters to be approved. The Audit Committee periodically monitors the services rendered by and actual fees paid to the independent registered public accounting firm to ensure that such services are within the parameters approved by the Audit Committee.

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.

(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 August 4, 2015, 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).

3.5 Certificate of Amendment of the 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 August 4, 2015, 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).

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).

4.7 Indenture, dated May 21, 2015, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and, Wilmington Trust, National Association, as trustee, governing the Second Lien Notes (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on May 22, 2015, and incorporated herein by reference).

4.8 Indenture, dated May 21, 2015, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and Wilmington Trust, National Association, as trustee, governing the Third Lien Notes (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on May 22, 2015 and incorporated herein by reference).

4.9 Form of Registration Rights Agreement, dated May 21, 2015, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and the initial purchaser, relating to the Second Lien Notes (filed as Exhibit 4.2 to the Company's Registration Statement on Form S-4 filed on October 2, 2015 and incorporated herein by reference).

4.10 Form of Registration Rights Agreement, dated May 21, 2015, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and the initial purchaser, relating to the Third Lien Notes (filed as Exhibit 4.2 to the Company's Registration Statement on Form S-4 filed on October 2, 2015 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).

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 Sixth 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, Sun Trust 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 25, 2015, and incorporated herein by reference).

10.11 Seventh Amendment to Second Amended and Restated Credit Agreement, dated as of May 21, 2015, among Midstates Petroleum Company, Inc., Midstates Petroleum Company, LLC, as borrower, SunTrust Bank, N.A., as administrative agent, and the lenders and other parties thereto (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K filed on May 22, 2015, and incorporated herein by reference).

10.12 Eighth Amendment to Second Amended and Restated Credit Agreement, dated as of August 5, 2015, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, as borrower, SunTrust Bank, N.A., as administrative agent, and the lenders and other parties thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on August 10, 2015, and incorporated herein by reference).

10.13 Ninth Amendment to Second Amended and Restated Credit Agreement, dated as of October 14, 2015, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, as borrower, Sun Trust Bank, N.A., as administrative agent, and the lenders and other parties thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 20, 2015, and incorporated herein by reference).

10.14 Intercreditor Agreement, dated May 21, 2015, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank, as priority lien agent, and Wilmington Trust, National Association, as second lien collateral agent and third lien collateral agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 22, 2015, and incorporated herein by reference).

10.15 Second Lien Pledge and Security Agreement, dated May 21, 2015, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and Wilmington Trust, National Association, as collateral agent (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on May 22, 2015, and incorporated herein by reference).

10.16 Third Lien Pledge and Security Agreement, dated May 21, 2015, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and Wilmington Trust, National Association, as collateral agent (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed on May 22, 2015, and incorporated herein by reference).

10.17 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).

10.18 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).

10.19 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).

10.20** 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).

10.21** 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).

10.22** 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).

10.23** 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).

10.24** Separation Agreement and General Release of Claims, dated as of December 10, 2015, 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 10, 2015, and incorporated herein by reference).

10.25** Separation Agreement and General Release of Claims, dated effective January 1, 2015, by and between Midstates Petroleum Company, Inc. and Dexter Burleigh (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).

10.26** 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).

10.27**	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).
10.28**	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).
10.29**	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. 30**	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).
10.31**	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).
10.32**	Executive Employment Agreement, dated as of March 9, 2015, by and between Midstates Petroleum Company, Inc. and Frederic F. Brace (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K/A filed on April 3, 2015, and incorporated herein by reference).
10.33	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 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

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 30, 2016

/s/ FREDERIC F. BRACE

Frederic F. Brace
Interim President and Chief Executive Officer
(Principal Executive Officer)

Dated: March 30, 2016

/s/ NELSON M. HAIGHT

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

Dated: March 30, 2016

KNOWN ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Frederic F. Brace 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/ FREDERIC F. BRACE Frederic F. Brace	Interim President and Chief Executive Officer (Principal Executive Officer)	March 30, 2016
/s/ NELSON M. HAIGHT Nelson M. Haight	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 30, 2016
/s/ ROBERT E. OGLE Robert E. Ogle	Director	March 30, 2016
/s/ ALAN J. CARR Alan J. Carr	Director	March 30, 2016
/s/ BRUCE H. STOVER Bruce H. Stover	Director	March 30, 2016
/s/ FREDERIC F. BRACE Frederic F. Brace	Director	March 30, 2016

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.
Tulsa, Oklahoma

We have audited the accompanying consolidated balance sheets of Midstates Petroleum Company, Inc. and subsidiary ("Midstates") as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2015. 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

The accompanying consolidated 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' event of default under the Credit Facility, a projected additional 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.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 30, 2016

MIDSTATES PETROLEUM COMPANY, INC.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share amounts)

	December 31, 2015	December 31, 2014 (As Adjusted, Note 3)
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$81,093	$11,557
Accounts receivable:		
Oil and gas sales	33,656	69,161
Joint interest billing	12,503	42,407
Other	17,506	22,193
Commodity derivative contracts	—	126,709
Other current assets	1,044	1,098
Total current assets	145,802	273,125
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of full-cost accounting	3,666,403	3,442,681
Other property and equipment	14,798	13,454
Less accumulated depreciation, depletion, amortization and impairment	(3,157,332)	(1,333,019)
Net property and equipment	523,869	2,123,116
OTHER ASSETS:		
Deferred income taxes	—	35,821
Other noncurrent assets	9,496	15,113
Total other assets	9,496	50,934
TOTAL	**$679,167**	**$2,447,175**
LIABILITIES AND EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable	$1,904	$22,783
Accrued liabilities	91,712	183,831
Debt classified as current less unamortized debt issuance costs (Note 2)	1,890,944	—
Deferred income taxes	—	44,862
Total current liabilities	1,984,560	251,476
LONG-TERM LIABILITIES:		
Asset retirement obligations	18,708	21,599
Long-term debt less unamortized debt issuance costs	—	1,706,532
Other long-term liabilities	1,965	1,706
Total long-term liabilities	20,673	1,729,837
COMMITMENTS AND CONTINGENCIES (Note 15)		
STOCKHOLDERS' EQUITY (DEFICIT):		
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 liquidation value at December 31, 2014; 8% cumulative dividends; no shares issued or outstanding at December 31, 2015 and 325,000 shares issued and outstanding at December 31, 2014	—	3
Common stock, $0.01 par value, 100,000,000 shares authorized; 10,962,105 shares issued and 10,865,814 shares outstanding at December 31, 2015 and 7,049,173 shares issued and 6,995,705 shares outstanding at December 31, 2014	110	70
Treasury stock	(3,081)	(2,592)
Additional paid-in-capital	888,247	882,528
Retained deficit	(2,211,342)	(414,147)
Total stockholders' equity (deficit)	(1,326,066)	465,862
TOTAL	**$679,167**	**$2,447,175**

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

MIDSTATES PETROLEUM COMPANY, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	For the Years Ended December 31,		
	2015	**2014**	**2013**
REVENUES:			
Oil sales	$217,636	$466,655	$387,226
Natural gas liquid sales	38,249	87,771	62,340
Natural gas sales	66,823	99,204	63,187
Gains (losses) on commodity derivative contracts—net	40,960	139,189	(44,284)
Other	1,477	1,364	1,037
Total revenues	365,145	794,183	469,506
EXPENSES:			
Lease operating and workover	81,473	79,598	73,414
Gathering and transportation	15,546	13,404	5,455
Severance and other taxes	8,605	24,266	27,237
Asset retirement accretion	1,610	1,706	1,435
Depreciation, depletion, and amortization	198,643	269,935	250,396
Impairment in carrying value of oil and gas properties	1,625,776	86,471	453,310
General and administrative	38,703	48,733	53,250
Acquisition and transaction costs	330	4,129	11,803
Debt restructuring costs and advisory fees	36,141	—	—
Other	2,121	5,108	615
Total expenses	2,008,948	533,350	876,915
OPERATING INCOME (LOSS)	(1,643,803)	260,833	(407,409)
OTHER INCOME (EXPENSE):			
Interest income	115	39	33
Interest expense—net of amounts capitalized	(163,148)	(137,548)	(83,138)
Total other expense	(163,033)	(137,509)	(83,105)
INCOME (LOSS) BEFORE TAXES	(1,806,836)	123,324	(490,514)
Income tax (expense) benefit	9,641	(6,395)	146,529
NET INCOME (LOSS)	**$(1,797,195)**	**$116,929**	**$(343,985)**
Preferred stock dividend	(948)	(10,378)	(15,589)
Participating securities—Series A Preferred Stock	—	(35,696)	—
Participating securities—Non-vested Restricted Stock	—	(3,584)	—
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS	**$(1,798,143)**	**$67,271**	**$(359,574)**
Basic and diluted net income (loss) per share attributable to common shareholders	$(232.74)	$10.13	$(54.68)
Basic and diluted weighted average number of common shares outstanding	7,726	6,644	6,576

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

MIDSTATES PETROLEUM COMPANY, INC.

CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY (DEFICIT)

(See Notes 10 and 11 for Share History)

(In thousands)

	Series A Preferred Stock	Common Stock	Treasury Stock	Additional Paid-in-Capital	Retained Deficit	Total Stockholders' Equity (Deficit)
Balance as of December 31, 2012	**$3**	**$67**	**$—**	**$864,490**	**$(187,091)**	**$677,469**
Share-based compensation	—	2	—	7,177	—	7,179
Acquisition of treasury stock	—	—	(664)	—	—	(664)
Net loss	—	—	—	—	(343,985)	(343,985)
Balance as of December 31, 2013	**$3**	**$69**	**$(664)**	**$871,667**	**$(531,076)**	**$339,999**
Share-based compensation	—	1	—	10,861	—	10,862
Acquisition of treasury stock	—	—	(1,928)	—	—	(1,928)
Net income	—	—	—	—	116,929	116,929
Balance as of December 31, 2014	**$3**	**$70**	**$(2,592)**	**$882,528**	**$(414,147)**	**$465,862**
Share-based compensation	—	3	—	5,753	—	5,756
Acquisition of treasury stock	—	—	(489)	—	—	(489)
Net loss	—	—	—	—	(1,797,195)	(1,797,195)
Conversion of preferred shares	(3)	37	—	(34)	—	—
Balance as of December 31, 2015	**$—**	**$110**	**$(3,081)**	**$888,247**	**$(2,211,342)**	**$(1,326,066)**

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

MIDSTATES PETROLEUM COMPANY, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2015	**2014**	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(1,797,195)	$116,929	$(343,985)
Adjustments to reconcile net loss to net cash provided by operating activities:			
(Gains) losses on commodity derivative contracts—net	(40,960)	(139,189)	44,284
Net cash received (paid) for commodity derivative contracts not designated as hedging instruments	167,669	(18,332)	(17,585)
Asset retirement accretion	1,610	1,706	1,435
Depreciation, depletion, and amortization	198,643	269,935	250,396
Impairment in carrying value of oil and gas properties	1,625,776	86,471	453,310
Share-based compensation, net of amounts capitalized to oil and gas properties	4,408	8,618	5,713
Deferred income taxes	(9,641)	5,586	(146,529)
Amortization of deferred financing costs	11,316	7,857	5,955
Paid-in-kind interest expense	6,415	—	—
Amortization of deferred gain on debt restructuring	(14,948)	—	—
Transaction costs for debt restructuring	34,398	—	—
Change in operating assets and liabilities:			
Accounts receivable—oil and gas sales	26,437	33,322	(66,865)
Accounts receivable—JIB and other	22,833	(18,897)	(18,002)
Other current and noncurrent assets	590	3,191	(1,802)
Accounts payable	(4,176)	2,327	(4,350)
Accrued liabilities	(20,887)	(7,733)	75,903
Other	1,095	(247)	(290)
Net cash provided by operating activities	**$213,383**	**$351,544**	**$237,588**
CASH FLOWS FROM INVESTING ACTIVITIES:			
Investment in property and equipment	(336,922)	(556,397)	(584,220)
Investment in acquired property	—	—	(620,112)
Proceeds from the sale of oil and gas properties	42,366	152,133	—
Net cash used in investing activities	**$(294,556)**	**$(404,264)**	**$(1,204,332)**
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	625,000	—	700,000
Proceeds from revolving credit facility	33,000	165,000	341,450
Repayment of revolving credit facility	(468,150)	(131,000)	(34,300)
Deferred financing costs	(4,254)	(958)	(25,457)
Transaction costs for debt restructuring	(34,398)	—	—
Acquisition of treasury stock	(489)	(1,928)	(664)
Net cash provided by financing activities	**$150,709**	**$31,114**	**$981,029**
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**$69,536**	**$(21,606)**	**$14,285**
Cash and cash equivalents, beginning of period	**$11,557**	**$33,163**	**$18,878**
Cash and cash equivalents, end of period	**$81,093**	**$11,557**	**$33,163**
SUPPLEMENTAL INFORMATION:			
Non-cash investment in property and equipment	$21,507	$95,000	$106,500
Non-cash components of Eagle Property Acquisition Purchase Price:			
—Deferred tax liability assumed	—	—	(727)
—Accrual for additional consideration	—	—	(941)
Non-cash components of Anadarko Basin Acquisition Purchase Price:			
—Asset retirement obligations assumed	—	—	6,296
—Accrual for miscellaneous liabilities assumed		(344)	3,030
Non-cash components of Pine Prairie Disposition:			
—Asset retirement obligation disposed	—	(7,652)	—
—Accrual for miscellaneous liabilities assumed	—	(2,185)	—
—Other noncurrent assets sold	—	371	—
Non-cash component of Dequincy Divestiture:			
—Asset retirement obligation disposed	(4,699)	—	—
Non-cash exchange of third lien notes for 2020 senior notes and 2021 senior notes	524,121	—	—
Cash paid for interest, net of capitalized interest of $4.9 million, $12.4 million and $32.2 million, respectively	161,285	129,511	72,085
Cash paid for taxes	—	209	—

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

MIDSTATES PETROLEUM COMPANY, INC.

Notes to Consolidated Financial Statements

1. Organization and Business

Midstates Petroleum Company, Inc., through its wholly-owned subsidiary Midstates Petroleum Company LLC, the only subsidiary of Midstates Petroleum Company, Inc., engages in the business of drilling for, and production of, oil, natural gas liquids (“NGLs”) and natural gas. 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 (“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, 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 Petroleum Company LLC became a wholly-owned subsidiary of Midstates Petroleum Company, Inc. and Midstates Petroleum Holdings LLC ceased to exist as a separate entity. The terms “Company,” “we,” “us,” “our,” and similar terms 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. The term “Holdings LLC” refers solely to Midstates Petroleum Holdings LLC prior to the corporate reorganization.

On October 1, 2012, the Company 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 and Kansas for $325.0 million in cash and 325,000 shares of the Company’s 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 the 2020 Senior Notes (as defined below).

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 $618.0 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 the 2021 Senior Notes (as defined below).

On March 5, 2014, the Company executed a Purchase and Sale Agreement (“PSA”) to sell 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 net proceeds of $147.7 million in cash (the “Pine Prairie Disposition”). Acreage subject to the transaction did not include acreage and production in the western part of Louisiana in Beauregard or Calcasieu Parishes or other undeveloped acreage held outside the Pine Prairie field. The sale closed on May 1, 2014.

On April 21, 2015, the Company closed the sale of all of its ownership interest in its Dequincy assets, which constituted its remaining producing and proved reserves properties in Louisiana (the “Dequincy Divestiture”) to Pintail Oil and Gas LLC. The net proceeds, inclusive of amounts placed in escrow, were approximately $42.4 million. With the completion of the Dequincy Divestiture, the Company no longer has any operations in the Louisiana/Gulf Coast area, although it does have approximately 11,757 net acres of undeveloped acreage under lease in Louisiana.

At December 31, 2015, the Company had oil and gas operations and properties in Oklahoma, Texas and Louisiana. The Company operates a significant portion of its oil and natural gas properties and is engaged in the exploration, development and production of oil, NGLs and natural gas.

On February 3, 2016, the Company received notice from the New York Stock Exchange (“NYSE”) that the Company’s common stock no longer met the NYSE continued listing requirements. As a result, the Company’s common stock was automatically delisted from the NYSE and began trading on an over the counter exchange.

2. Liquidity and Ability to Continue as a Going Concern

The Company’s decisions on capital structure, hedging and drilling are based upon widely available information of anticipated future commodity pricing and expected economic conditions. The unexpected substantial decrease in oil and gas prices that began in the second half of 2014 and continued throughout 2015 and into 2016 has resulted in materially lower operating cash flows than expected. The Company’s hedging contracts helped to mitigate the impact of lower commodity prices during 2015 and the Company received cash settlements of these derivatives of $167.7 million, which comprised 78.6% of its cash provided by operations during 2015. However, all of the Company’s hedging contracts expired during 2015, and as a result, the Company will not receive any cash derivative settlements for 2016 or future periods, which will materially lower cash provided by operations in those future periods as compared to its historical operating cash flows.

As a result of the commodity price decline and the Company's substantial debt burden, the Company took steps to increase its liquidity and amend certain debt covenants during 2015. On April 21, 2015, the Company closed on the Dequincy Divestiture for approximately $44.0 million, before customary post-closing adjustments.

Additionally, on May 21, 2015, the Company sold $625.0 million of 10.0% Second Lien Notes due 2020 (the "Second Lien Notes") and utilized a portion of the proceeds to repay the outstanding balance of its reserve based revolving credit facility (the "Credit Facility") of approximately $468.2 million. Further, the Company exchanged approximately $504.1 million of 12.0% Third Lien Notes due 2020 (the "Third Lien Notes") for approximately $279.8 million of the 10.75% Senior Unsecured Notes due 2020 (the "2020 Senior Notes") and $350.3 million of the 9.25% Senior Unsecured Notes due 2021(the "2021 Senior Notes", together with the 2020 Senior Notes the "Unsecured Notes", and together with the Second Lien Notes and the Third Lien Notes the "Senior Notes"), representing an exchange at 80.0% of the exchanged Unsecured Notes' par value. Furthermore, on June 2, 2015, the Company exchanged approximately $20.0 million of Third Lien Notes for approximately $26.6 million of 2020 Senior Notes and $2.0 million of 2021 Senior Notes, representing an exchange at 70.0% of the exchanged Unsecured Notes' par value. For further information regarding the Second Lien Notes, Third Lien Notes and updates to the Company's debt covenants, see "—Note 9. Debt." These transactions increased the liquidity position of the Company; however, due to depressed commodity prices, the Company continues to face the risk of a liquidity shortfall.

The terms of the Credit Facility and the indentures governing the Senior Notes require that some or all of the proceeds from asset sales, if any, must be used to permanently reduce outstanding debt, which could substantially reduce the amount of proceeds ultimately retained and therefore reduce the impact to the Company's liquidity as a result of any such sale. Further, the covenants in these debt instruments impose limitations on the amount and type of additional indebtedness the Company can incur, which may significantly reduce its ability to obtain liquidity through the incurrence of additional indebtedness. The ability to refinance any of the existing indebtedness on commercially reasonably terms will likely be materially and adversely impacted by the current conditions in the energy industry and the Company's financial condition.

The Company has substantial interest payment obligations related to its debt over the next twelve months. As of December 31, 2015, payments due on contractual obligations during the next twelve months were approximately $188.0 million comprised of approximately $179.5 million of interest payments on the Senior Notes and other operating expenses such as fixed drilling commitments and operating leases.

As a result of the sustained commodity price decline and the Company's substantial debt burden, the Company believes that forecasted cash and available credit capacity will not be sufficient to meet commitments as they come due over the next twelve months, and it will not be able to remain in compliance with current debt covenants unless it is able to successfully increase liquidity or deleverage. The uncertainty associated with the ability to meet commitments as they come due or to repay outstanding debt raises substantial doubt about the Company's ability to continue as a going concern. The consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern.

The Company is required to receive an unqualified auditors' opinion in relation to the 2015 consolidated financial statements. The failure to receive an unqualified opinion is an event of default under the Credit Facility that must be cured within 30 days of such event or waived by the lenders under the Credit Facility. In consideration of the uncertainty mentioned above, the report of the Company's independent registered public accounting firm that accompanies our audited consolidated financial statements for the year ended December 31, 2015 in this Annual Report on Form 10-K contains an explanatory paragraph regarding an event of default under the Credit Facility, a projected additional debt covenant violation, and resulting lack of liquidity, which raises substantial doubt about the Company's ability to continue as a going concern.

The report of the Company's independent registered public accounting firm that accompanied its consolidated financial statements for the year ended December 31, 2014 also contained an explanatory paragraph regarding a projected debt covenant violation and resulting lack of liquidity raising substantial doubt about its ability to continue as a going concern; however, the Company obtained a waiver from its lenders under the Credit Facility waiving any default as a result of receiving such explanatory paragraph in 2014. The Company has not received a similar waiver from its lenders under the Credit Facility for the explanatory paragraph to its 2015 independent registered public accounting firm report. As a result, the Company is in default under its Credit Facility. A failure to cure this default within 30 days will result in the acceleration of all of the Company's indebtedness under the Credit Facility. If the lenders under the Company's Credit Facility accelerate the loans outstanding thereunder, the Company will then also be in default under the indentures governing its Senior Notes, in which case the lenders under the indentures governing its Senior Notes could accelerate the repayment thereof.

If lenders, and subsequently noteholders, accelerate the Company's outstanding indebtedness, it will become immediately due and payable and the Company will not have sufficient liquidity to repay those amounts. If we are unable to reach an agreement with our creditors prior to any of the above described accelerations, we could be required to immediately file for protection under Chapter 11 of the U.S. Bankruptcy Code.

The Company's long-term debt with maturities summarized in Note 9 is reflected as a current liability in its consolidated balance sheet at December 31, 2015. The classification as a current liability is based on the uncertainty regarding the Company's ability to cure the default discussed above and to comply with certain restrictive covenants contained in its Credit Facility and cross default/cross acceleration provisions in the indentures governing the Senior Notes.

In order to increase the Company's liquidity to levels sufficient to meet the Company's commitments, the Company is currently undertaking a number of actions, including minimizing capital expenditures, aggressively managing working capital and further reducing its recurring operating expenses. The Company believes that even after taking these actions, it will not have sufficient liquidity to satisfy its debt service obligations, meet other financial obligations, and comply with its debt covenants. The Company has engaged financial and legal advisors to, among other things, assist with analyzing various strategic alternatives to address its liquidity and capital structure. The Company believes a filing under Chapter 11 of the U.S. Bankruptcy Code may provide the most expeditious manner in which to effect a capital structure solution. There can be no assurance the Company will be able to restructure its capital structure on terms acceptable to the Company, its creditors, or at all.

In February 2016, the Company borrowed approximately $249.2 million under the Credit Facility, which represented the remaining undrawn amount that was available under the Credit Facility and as a result, as of February 9, 2016, the Company had a cash balance of approximately $335.7 million.

The Company's next scheduled interest payment is April 1, 2016 for $15.8 million to the holders of the 2020 Senior Notes and the Company is currently evaluating whether such interest payment will be made. If the payment is not made by April 1, 2016, the Company would have 30 days to cure such payment default before an event of default occurs.

Financial Ratio Covenants

The Credit Facility contains, among other standard affirmative and negative covenants, financial covenants including a maximum ratio of Total Senior Indebtedness (as defined therein) to EBITDA (as defined therein) of not more than 1.0 to 1.0 and a minimum current ratio (as defined therein) of not less than 1.0 to 1.0. The Credit Facility also limits the Company's ability to make any dividends, distributions or redemptions.

Borrowing Base Redetermination

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. If commodity prices remain depressed or deteriorate further, the borrowing base under the Credit Facility will likely be reduced. Since the Credit Facility was fully drawn subsequent to December 31, 2015, any reduction in the borrowing base will result in a deficiency in the amount that our borrowings exceed the borrowing base, which must be repaid within 30 days or in six equal monthly installments thereafter, at our election. The Company may not have the financial resources to make any mandatory deficiency principal repayments, which could result in an event of default under the Credit Facility.

Cross Default Provisions

The 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 the 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.

3. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements of the Company have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") and have been prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP").

All intercompany transactions have been eliminated in consolidation. The consolidated financial statements as of and for the year ended December 31, 2015 include the results of the Dequincy Divestiture from January 1, 2015 through April 21, 2015, the date of disposition. The consolidated financial statements as of and for the year ended December 31, 2014 include the results of the Pine Prairie Disposition from January 1, 2014 through May 1, 2014, the date of disposition. The consolidated financial statements for the year ended December 31, 2013 include the results from the Anadarko Basin Acquisition beginning May 31, 2013. The Company's management evaluates performance based on one reportable segment as all its operations are located in the United States and therefore it maintains one cost center.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company utilizes historical experience as well as other assumptions that are believed to be reasonable under the circumstances in preparing its estimates. The Company evaluates estimates and assumptions on a regular basis. Actual results could differ from those estimates and assumptions used in the preparation of the Company's financial statements.

Significant estimates include, but are not limited to, the estimate of recoverable oil and natural gas reserves and related present value estimates of future net cash flows derived therefrom, legal and environmental risks and exposures, the fair value of commodity derivative contracts, the fair value of share-based compensation, and the valuation of future asset retirement obligations.

Cash and Cash Equivalents

The Company considers all short-term investments with an original maturity of three months or less to be cash equivalents. The Company's total cash balances are insured by the Federal Deposit Insurance Corporation ("FDIC") up to $250,000 per bank per depositor. The Company had cash balances on deposit at December 31, 2015 and 2014 that exceeded the balance insured by the FDIC in the amount of $87.2 million and $34.3 million, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are stated at the historical carrying amount net of any allowance for uncollectible accounts. The carrying amount of the Company's accounts receivable approximate fair value because of the short-term nature of the instruments. Many of the Company's receivables are from joint interest owners in properties in which the Company is the operator. The Company may withhold future revenue disbursements to recover any non-payment of these joint interest billings under certain circumstances. The Company routinely assesses the collectability of all material trade and other receivables and the Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated. As of December 31, 2015 and 2014, the Company had no allowance for doubtful accounts.

Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, receivables, payables, debt, and commodity derivative contracts. Commodity derivative contracts are recorded at fair value; see "—Note 4. Fair Value Measurements of Financial Instruments". The fair value of the Company's long-term debt is disclosed, see "—Note 9. Debt". The carrying amount of the Company's other financial instruments approximate fair value because of the short term nature of the items or variable pricing.

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

Other Noncurrent Assets

At December 31, 2015 and 2014, other noncurrent assets consisted of the following:

	At December 31,	
	2015	2014 (As Adjusted, Note 3)
	(in thousands)	
Deferred financing costs associated with the Credit Facility	$6,105	$9,189
Field equipment inventory	3,225	5,713
Other	166	211
Other noncurrent assets	**$9,496**	**$15,113**

For the years ended December 31, 2015 and 2014, the Company recorded $2.0 million and $4.1 million, respectively, of losses on the sale of, or market value adjustments to, field equipment inventory.

Property and Equipment

Oil and Gas Properties

The Company uses the full-cost method of accounting for its exploration and development activities. Under this method of accounting, costs of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds from the sale or disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion of the Company's reserve quantities are sold such that it results in a significant alteration of the relationship between capitalized costs and remaining proved reserves, in which case a gain or loss is generally recognized in income.

Unevaluated Property

Oil and gas unevaluated properties and properties under development include costs that are not being depleted or amortized. These costs represent investments in unproved properties. The Company excludes these costs until proved reserves are found, until it is determined that the costs are impaired or until major development projects are placed in service, at which time the costs are moved into oil and natural gas properties subject to amortization. All unproved property costs are reviewed at least annually to determine if impairment has occurred.

During 2015, the Company transferred the remaining unevaluated property balance consisting of $56.3 million of Mississippian unevaluated property costs, $0.2 million of Anadarko Basin unevaluated property costs and $0.1 million of Gulf Coast unevaluated property costs to the full cost pool as a result of current pricing, its anticipated drilling plans and uncertainty regarding its ability to finance its future exploration activities. During 2014, the Company transferred $59.2 million of Mississippian unevaluated property costs to the full cost pool. These costs were attributable to leases that either expired during 2014, were determined to not be prospective, or that were assigned proved reserves as a result of the Company's development drilling activities. The Company also transferred $128.2 million of Anadarko Basin and $16.5 million of Gulf Coast unevaluated property costs based upon our lack of plans for further evaluation or development of those leases in the current commodity price environment.

Oil and Gas Reserves

Proved oil, NGLs and natural gas reserves utilized in the preparation of the consolidated financial statements are estimated in accordance with the rules established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions using a 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. The Company depletes its oil and gas properties using the units-of-production method. Capitalized costs of oil and natural gas properties subject to amortization are depleted over proved reserves. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Impairment of Oil and Gas Properties/Ceiling Test

The Company performs a full-cost ceiling test on a quarterly basis. The test establishes a limit, or 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 prices received by the Company as of the first trading day of each month over the preceding twelve months (such prices are 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 expense in the accompanying consolidated statements of operations. For the years ended December 31, 2015, 2014 and 2013, the Company recorded impairments of oil and gas properties of $1.6 billion, $86.5 million and $453.3 million respectively. A significant decline in the average oil and natural gas sales price utilized in calculating the present value of estimated future net revenues from projected production of oil and gas reserves was the primary factor that led to the full-cost ceiling impairments for the year ended December 31, 2015. For the years ended December 31, 2014 and 2013, the primary factors affecting the impairment related to the transfer of unevaluated property costs to the full cost pool and negative reserve revisions in certain areas.

Depletion

Depletion of oil and gas properties is calculated using the units of production method ("UOP"). The UOP calculation, in its simplest terms, multiplies the percentage of estimated proved reserves produced by the cost of those reserves. The result is to recognize expense at the same pace that the reserves are estimated to be depleting. The amortization base in the UOP calculation includes the sum of proved property costs net of accumulated depletion, estimated future development costs (future costs to access and develop proved reserves) and asset retirement costs that are not already included in oil and gas property, less related salvage value.

Capitalized Interest

Interest from external borrowings is capitalized on unevaluated properties using the weighted-average cost of outstanding borrowings until the project is substantially complete and ready for its intended use, which for oil and gas assets is at the date of first production from the field. Capitalized interest is depleted over the useful lives of the assets in the same manner as the depletion of the underlying assets.

Other Property and Equipment

Other property and equipment consists of vehicles, furniture and fixtures, and computer hardware and software and is carried at cost. Depreciation is provided principally using the straight-line method over the estimated useful lives of the assets, which primarily range from three to seven years. Maintenance and repairs are charged to expense as incurred, while renewals and betterments are capitalized.

Accrued Liabilities

At December 31, 2015 and 2014, accrued liabilities consisted of the following:

	At December 31,	
	2015	**2014**
	(in thousands)	
Accrued oil and gas capital expenditures	$19,984	$76,398
Accrued revenue and royalty distributions	27,939	51,292
Accrued lease operating and workover expense	9,281	10,113
Accrued interest	20,193	21,521
Accrued taxes	1,272	4,226
Compensation and benefit related accruals	8,414	10,766
Other	4,629	9,515
Accrued liabilities	**$91,712**	**$183,831**

Asset Retirement Obligations

The legal obligations associated with the retirement of long-lived assets are recognized at estimated fair value at the time that the obligation is incurred.

Oil and gas producing companies incur such a liability upon drilling or acquiring a well. The Company estimates the fair value of an asset retirement obligation in the period in which the obligation is incurred and can be reliably measured. The corresponding asset retirement cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depleted over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, any adjustment is recorded to the full cost pool. See "—Note 8. Asset Retirement Obligations".

Share-Based Compensation

The Company measures share-based compensation cost at fair value and generally recognizes the corresponding compensation expense on a straight-line basis over the service period during which awards are expected to vest. Share-based compensation expense, net of amounts capitalized to oil and gas properties, is included in "General and administrative expense" in our consolidated statements of operations. See "—Note 11. Equity and Share-Based Compensation".

Revenue Recognition

Oil, NGLs and natural gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and collection of the revenues is reasonably assured. Cash received relating to future revenues is deferred and recognized when all revenue recognition criteria are met.

The Company follows the sales method of accounting for oil, NGLs and gas revenues, whereby revenue is recognized for all oil, NGLs and gas sold to purchasers regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as a liability to the extent an imbalance on a specific property exceeds the Company's share of remaining proved oil and gas reserves. The Company had no significant imbalances at December 31, 2015, 2014 or 2013.

Acquisition and Transaction Costs

Acquisition and transaction related costs are expensed as incurred and as services are received. Such costs include finders' fees, advisory, legal, accounting, valuation and other professional and consulting fees, and acquisition related general and administrative costs. Costs incurred in 2015 relate to the Dequincy Divestiture and costs incurred in 2014 relate to the Pine Prairie Disposition. Costs incurred in 2013 relate to the Anadarko Basis Acquisition. See "—Note 7. Acquisition and Divestitures of Oil and Gas Properties".

Income Taxes

Income taxes are recorded for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or liabilities are settled. Deferred income taxes also include tax credits and net operating losses that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted tax rates.

The Company accounts for uncertainty in income taxes for tax positions taken or expected to be taken in a tax return. Only tax positions that meet the more-than-likely-than-not recognition threshold are recognized.

Earnings (Loss) Per Share

Basic earnings (loss) per common share is calculated by dividing net income (loss) available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings (loss) per common share is calculated by dividing net income (loss) available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options (if any) using the treasury method, as well as the Company's Series A Preferred Stock using the if-converted method (in periods prior to the Preferred Stock's mandatory conversion date). In the computation of diluted earnings per share, excess tax benefits that would be created upon the assumed vesting of unvested restricted shares or the assumed exercise of stock options (i.e. hypothetical excess tax benefits) are included in the assumed proceeds component of the treasury share method to the extent that such excess tax benefits are more likely than not to be realized. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. See "—Note 13. Earnings (Loss) Per Share."

Recent Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update 2014-09, *"Revenue from Contracts with Customers (Topic 606)*" ("ASU 2014-09"). ASU 2014-09 provides guidance concerning the recognition and measurement of revenue from contracts with customers. The objective of ASU 2014-09 is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. ASU 2014-09 requires an entity to (i) identify the contract(s) with a customer, (ii) identify the performance obligations in the contract(s), (iii) determine the transaction price, (iv) allocate the transaction price to the performance obligations in the contract(s), and (v) recognize revenue when, or as, the entity satisfies a performance obligation. ASU 2014-09 will be effective for the Company beginning on January 1, 2018, including interim periods within that reporting period, considering the one year deferral provided by ASU 2015-14, *"Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date."* The standard permits the use of either the retrospective or cumulative effect transition method and early adoption is permitted. The Company has not selected a transition method and is evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

In April 2015, the FASB issued Accounting Standards Update 2015-03, *"Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs"* ("ASU 2015-03") and in August 2015 issued Accounting Standards Update 2015-15, *"Interest—Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements—Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting (SEC Update)"* ("ASU 2015-15"). The ASUs provide that the debt issuance costs are similar to debt discounts and in effect reduce the proceeds of borrowings. ASU 2015-03 amends the FASB ASC to require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the related liability. Prior to the amendment, debt issuance costs were reported in the balance sheet as an asset. ASU 2015-15 further clarified that given ASU 2015-03's silence on debt issuance costs related to revolving credit facilities, the SEC would not object to debt issuance costs for revolving credit facilities being deferred and presented as an asset. The amended guidance is effective for financial statements issued for fiscal years beginning after December 15, 2015; however the Company elected to early adopt effective December 31, 2015. The election requires retrospective application and represents a change in accounting principle. As a result of the adoption, the December 31, 2014 consolidated balance sheet has been adjusted as follows:

	December 31, 2014		
	Previously Reported	**Effect of Accounting Principle Adoption**	**As Adjusted**
		(in thousands)	
Assets:			
Other noncurrent assets	$43,731	$(28,618)	$15,113
Total other assets	79,552	(28,618)	50,934
Total assets	2,475,793	(28,618)	2,447,175
Liabilities:			
Long-term debt less unamortized debt issuance costs	$1,735,150	$(28,618)	$1,706,532
Total long-term liabilities	1,758,455	(28,618)	1,729,837
Total liabilities and shareholders' equity	2,475,793	(28,618)	2,447,175

Debt costs associated with the Company's revolving credit facility, under which no borrowings were outstanding at December 31, 2015, remain classified as an asset in accordance with the Company's accounting policy that debt costs related to revolving credit arrangements are deferred and amortized over the term of the arrangement.

In September 2015, the FASB issued Accounting Standards Update 2015-16, *"Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments"* ("ASU 2015-16"). ASU 2015-16 simplifies measurement period adjustments associated with business combinations accounted for under FASB ASC 805, *Business Combinations*. ASU 2015-16 changes the accounting for measurement period adjustments by eliminating the requirement that such adjustments are made retrospectively. As a result, such measurement period adjustments will be recognized in the reporting period in which the adjustment was determined. ASU 2015-16 is applied prospectively to adjustments to provisional amounts that occur after the effective date. ASU 2015-16 is effective for the Company beginning on January 1, 2016. The Company does not believe the adoption of ASU 2015-16 will have a material impact on its financial position, results of operations or cash flows.

In November 2015, the FASB issued Accounting Standards Update 2015-17, *"Balance Sheet Classification of Deferred Taxes,"* ("ASU 2015-17") which requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent in the balance sheet. As a result, the Company now only presents its deferred income taxes on a net noncurrent basis. However, the new guidance does not change the existing requirement that only permits offsetting within a jurisdiction. Companies are still prohibited from offsetting deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. The amendments in this accounting standard are effective for public companies for interim and annual reporting periods beginning after December 15, 2016, with early application permitted. The Company has early adopted this standard and has applied the change in accounting as of December 31, 2015 on a prospective basis. Adoption of this amendment did not have an effect on the Company's financial position or results of operations, and prior periods were not retrospectively adjusted.

In February 2016, the FASB issued Accounting Standards Update 2016-02, *"Leases (Topic 842)"* ("ASU 2016-02"). ASU 2016-02 establishes a right-of-use ("ROU") model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new standard is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Company is currently evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

4. Fair Value Measurements of Financial Instruments

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further divided into the following fair value input hierarchy:

- **Level 1—**Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

- **Level 2—**Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are commodity derivative contracts with fair values based on inputs from actively quoted markets. The Company uses a discounted cash flow approach to estimate the fair values of its commodity derivative contracts, utilizing commodity futures price strips for the underlying commodities provided by a reputable third-party.

- **Level 3—**Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability.

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Derivative Instruments—Commodity derivative contracts reflected in the consolidated balance sheets are recorded at estimated fair value. The Company's derivative contracts all expired as of December 31, 2015. As of December 31, 2014, the Company's commodity derivative contracts were with seven counterparties and were classified as Level 2.

	Fair Value Measurements at December 31, 2014			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Commodity derivative oil swaps	$—	$106,450	$—	$106,450
Commodity derivative gas swaps	—	20,259	—	20,259
Total assets	**$—**	**$126,709**	**$—**	**$126,709**
Liabilities:				
Commodity derivative oil swaps	$—	$—	$—	$—
Commodity derivative gas swaps	—	—	—	—
Total liabilities	**$—**	**$—**	**$—**	**$—**

Derivative instruments listed above are presented gross and include swaps that are carried at fair value. The Company records the net change in the fair value of these positions in "Gains (losses) on commodity derivative contracts—net" in the Company's consolidated statements of operations. See "—Note 5. Risk Management and Derivative Instruments" for additional information on the Company's derivative instruments and balance sheet presentation.

5. Risk Management and Derivative Instruments

The Company's production is exposed to fluctuations in crude oil, NGLs and natural gas prices. The Company believes it is prudent to manage the variability in cash flows by, at times, entering into derivative financial instruments to economically hedge a portion of its crude oil, NGLs and natural gas production. The Company has historically utilized various types of derivative financial instruments, including swaps and collars, to manage fluctuations in cash flows resulting from changes in commodity prices. These derivative contracts are placed with major financial institutions that the Company believes are minimal credit risks. The oil, NGLs and gas reference prices, upon which the commodity derivative contracts are based, reflect various market indices that management believes have a high degree of historical correlation with actual prices received by the Company for its oil, NGLs and natural gas production. Although the Company has entered into derivative financial instruments in the past on an ongoing basis, the Company currently has no derivatives in place as of and for any period subsequent to December 31, 2015.

Inherent in the Company's portfolio of commodity derivative contracts are certain business risks, including market risk and credit risk. Market risk is the risk that the price of the commodity will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the Company's counterparty to a contract. The Company does not require collateral from its counterparties but does attempt to minimize its credit risk associated with derivative instruments by entering into derivative instruments only with counterparties that are large financial institutions, which management believes present minimal credit risk. In addition, to mitigate its risk of loss due to default, the Company has entered into agreements with its counterparties on its derivative instruments that allow the Company to offset its asset position with its liability position in the event of default by the counterparty.

Commodity Derivative Contracts

As of December 31, 2015, the Company did not have any open commodity derivative contract positions.

Balance Sheet Presentation

The following table summarizes the gross fair value of derivative instruments by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company's consolidated balance sheets at December 31, 2015 and 2014, respectively (in thousands):

Type	Balance Sheet Location(1)	December 31, 2015	December 31, 2014
Oil Swaps	Derivative financial instruments—Current Assets	$—	$106,450
Gas Swaps	Derivative financial instruments—Current Assets	—	20,259
Total derivative fair value at period end		**$—**	**$126,709**

(1) The fair values of commodity derivative instruments reported in the Company's consolidated balance sheets are subject to netting arrangements and qualify for net presentation. As of December 31, 2015, the Company did not have any open commodity derivative contract positions. The following table summarizes the location and fair value amounts of all derivative instruments in the consolidated balance sheet, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheet at December 31, 2014 (in thousands):

		December 31, 2014		
Not Designated as ASC 815 Hedges:	**Balance Sheet Classification**	**Gross Recognized Assets/ Liabilities**	**Gross Amounts Offset**	**Net Recognized Fair Value Assets/ Liabilities**
Derivative assets:				
Commodity contracts	Derivative financial instruments—current	$126,709	$—	$126,709
Commodity contracts	Derivative financial instruments—noncurrent	—	—	—
		$126,709	**$—**	**$126,709**
Derivative liabilities:				
Commodity contracts	Derivative financial instruments—current	$—	$—	$—
Commodity contracts	Derivative financial instruments—noncurrent	—	—	—
		$—	**$—**	**$—**

Gains/Losses on Commodity Derivative Contracts

The Company does not designate its commodity derivative contracts as hedging instruments for financial reporting purposes. Accordingly, commodity derivative contracts are marked-to-market each quarter with the change in fair value during the periodic reporting period recognized currently as a gain or loss in "Gains (losses) on commodity derivative contracts—net" within revenues in the consolidated statements of operations.

The following table presents net cash received (paid) for commodity derivative contracts and unrealized net gains (losses) recorded by the Company related to the change in fair value of the derivative instruments in "Gains (losses) on commodity derivative contracts—net" for the periods presented:

	For the Years Ended		
	2015	**2014**	**2013**
		(in thousands)	
Net cash received (paid) for commodity derivative contracts	$167,669	$(18,332)	$(17,585)
Unrealized net gains (losses)	(126,709)	157,521	(26,699)
Gains (losses) on commodity derivative contracts—net	**$40,960**	**$139,189**	**$(44,284)**

Cash settlements, as presented in the table above, represent realized gains related to the Company's derivative instruments. In addition to cash settlements, the Company also recognizes fair value changes on its derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves.

6. Property and Equipment

The Company's property and equipment as of December 31, 2015 and 2014 was as follows:

	December 31, 2015	**December 31, 2014**
	(in thousands)	
Oil and gas properties, on the basis of full-cost accounting:		
Proved properties	$3,666,403	$3,398,146
Unevaluated properties	—	44,535
Other property and equipment	14,798	13,454
Less accumulated depreciation, depletion, amortization and impairment	(3,157,332)	(1,333,019)
Net property and equipment	**$523,869**	**$2,123,116**

For the years ended December 31, 2015, 2014 and 2013, depletion expense related to oil and gas properties was $195.2 million, $266.8 million, and $248.2 million, respectively and $16.26, $22.75 and $28.42 per barrel of oil equivalent ("Boe"), respectively. For the years ended December 31, 2015, 2014 and 2013, depreciation expense related to other property and equipment was $3.5 million, $3.1 million and $2.2 million, respectively.

For the years ended December 31, 2015, 2014 and 2013, interest capitalized to unevaluated properties was $4.9 million, $12.4 million and $32.2 million, respectively. For the years ended December 31, 2015, 2014 and 2013, the Company capitalized $7.3 million, $12.4 million and $8.4 million, respectively, of internal costs to oil and gas properties, including $1.3 million, $2.2 million and $1.4 million, respectively, of qualifying share based compensation expense, see "—Note 11. Equity and Share Based Compensation".

7. Acquisition and Divestitures of Oil and Gas Properties

Dequincy Divestiture

On April 21, 2015, the Company closed the Dequincy Divestiture for $44.0 million, completing the Company's disposition of its producing properties and proved reserves in Louisiana. The net proceeds, inclusive of amounts placed in escrow, were approximately $42.4 million, which was net of customary closing adjustments. This amount was reflected as a reduction of oil and natural gas properties, with no gain or loss recognized. The net proceeds were retained for general corporate purposes.

Pine Prairie Disposition

On March 5, 2014, the Company executed an agreement to sell 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 $170.0 million in cash, subject to standard post-closing adjustments. Acreage subject to the transaction did not include acreage and production in the western part of Louisiana in Beauregard and Calcasieu Parishes or other undeveloped acreage held outside the Pine Prairie field. On May 1, 2014, the Company closed on the sale for net proceeds of $147.7 million, of which $131.0 million was used to reduce amounts outstanding under its Credit Facility, with the remainder retained for transaction expenses and working capital purposes. The Company reduced the full cost pool subject to amortization by the amount of the net proceeds received and no gain or loss was recognized.

Exploration Agreement with PetroQuest

On June 25, 2014, the Company entered into an exploration agreement with PetroQuest Energy LLC ("PetroQuest") with an effective date of May 1, 2014, in which the Company conveyed to PetroQuest an undivided 50% of its right, title and interest in and to the acreage and other interests in the Fleetwood prospect area in Louisiana. With the execution of the agreement, PetroQuest paid $3.0 million in cash consideration and in January 2015, PetroQuest paid additional cash of $7.0 million. As further consideration, PetroQuest granted a credit to the Company of an additional non-interest bearing total sum of $14.0 million, to be credited or paid against the Company's share of costs 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 credited on or before December 31, 2015, the Company could elect to take the remaining portion in cash. The Company requested the unutilized portion of the non-interest bearing amount of approximately $4.4 million be refunded. The refund was received in February 2016 and has been included in "accounts receivable—other" on the Company's consolidated balance sheet as of December 31, 2015.

Anadarko Basin Acquisition

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 $618.0 million in cash (before customary post-closing adjustments). The Company funded the purchase price of the Anadarko Basin Acquisition with a portion of the net proceeds from the private placement of the 2021 Senior Notes, which also closed on May 31, 2013.

The transaction was accounted for using the acquisition method of accounting which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The fair value of, and the allocation to, the assets acquired and liabilities assumed in the Anadarko Basin Acquisition has been finalized and is shown in the following table (in thousands):

	Anadarko Basin Acquisition
Oil and gas properties	
Proved	$417,750
Unevaluated	207,606
Total assets acquired	**$625,356**
Asset retirement obligations	6,296
Total liabilities assumed	**$6,296**
Net assets acquired	**$619,060**

The finalized balances in the table above include immaterial changes to the amounts originally allocated to oil and gas properties. These changes were required to reflect the final consideration paid after adjustment for certain post-closing purchase price amounts.

Actual and Pro Forma Impact of Acquisition—unaudited

Revenues attributable to the Anadarko Basin Acquisition included in the Company's consolidated statements of operations for the year ended December 31, 2014 and 2013 were $178.9 million and $104.7 million, respectively.

The following table presents unaudited pro forma information for the Company as if the Anadarko Basin Acquisition had been completed on January 1, 2013 (in thousands, other than per share amounts):

	For the Year Ended December 31, 2013
Revenues and other	$539,562
Net loss	(340,400)
Preferred stock dividends	(15,589)
Loss attributable to common shareholders	$(355,989)
Net loss per common share—basic and diluted	$(54.13)

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Anadarko Basin Acquisition and are factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the Company's consolidated results of operations actually would have been had the Anadarko Basin Acquisition been completed on January 1, 2013. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations for the combined Company.

Acquisition and Transaction Expenses

For the year ended December 31, 2015, acquisition and transaction costs of $0.3 million relate to the execution of the Dequincy Divestiture.

For the year ended December 31, 2014, acquisition and transaction costs of $4.1 million were incurred primarily as a result of the Pine Prairie Disposition and include advisory, legal, accounting, valuation and other professional and consulting fees related to the sale.

For the year ended December 31, 2013, acquisition and transaction costs of $11.8 million were incurred as a result of the Anadarko Basin Acquisition and include advisory, legal, accounting, valuation and other professional and consulting fees related to the acquisition.

8. Asset Retirement Obligations

For the Company, asset retirement obligations "(AROs") represent the future abandonment costs of tangible assets, such as wells, service assets and other facilities. The fair value of the asset retirement obligation at inception is capitalized as part of the carrying amount of the related long-lived asset. Asset retirement obligations approximated $18.7 million and $21.6 million as of December 31, 2015 and 2014, respectively. The liability has been accreted to its present value as of December 31, 2015 and 2014. At December 31, 2015 and 2014, all asset retirement obligations represent long-term liabilities and are classified as such.The following table details the change in the asset retirement obligations for the years ended December 31, 2015, 2014 and 2013, respectively (in thousands):

	Year ended December 31,		
	2015	2014	2013
Asset retirement obligations at beginning of year	**$21,599**	**$26,308**	**$15,245**
Liabilities incurred	127	996	2,535
Liabilities assumed in Anadarko Basin Acquisition	—	—	6,296
Revisions(1)	570	288	858
Liabilities settled	(279)	(47)	(61)
Liabilities eliminated through asset sale(2)	(4,919)	(7,652)	—
Current period accretion expense	1,610	1,706	1,435
Asset retirement obligations at end of year	**$18,708**	**$21,599**	**$26,308**

(1) Revisions during the year ended December 31, 2015 were the result of updates to the estimated abandonment dates of various wells. Revisions during the years ended December 31, 2014 and 2013 were due primarily to an increase in estimated future abandonment costs based upon higher costs for oilfield services and materials in the Mississippian Lime and Anadarko areas.

(2) Liabilities eliminated through asset sales for the year ended December 31, 2015 is primary related to the Dequincy Divestiture. Liabilities eliminated through asset sales for the year ended December 31, 2014 were related to the Pine Prairie Disposition. See discussion of the Dequincy Divestiture and Pine Prairie Disposition in "—Note 7. Acquisition and Divestitures of Oil and Gas Properties".

9. Debt

The Company's total debt, including debt classified as current, as of December 31, 2015 and 2014 is as follows:

	Principal		Unamortized Deferred Gain on Debt Forgiven		Unamortized Debt Issuance Costs		Total	
	2015	2014	2015	2014	2015	2014	2015	2014
			(in thousands)					
Credit Facility	$—	$435,150	$—	$—	$—	$—	$—	$435,150
2020 Senior Notes	293,625	600,000	—	—	(11,344)	(13,475)	282,281	586,525
2021 Senior Notes	347,652	700,000	—	—	(13,296)	(15,143)	334,356	684,857
Second Lien Notes	625,000	—	42,293	—	—	—	667,293	—
Third Lien Notes	529,653	—	77,361	—	—	—	607,014	—
Total debt	**$1,795,930**	**$1,735,150**	**$119,654**	$—	**$(24,640)**	**$(28,618)**	**$1,890,944**	**$1,706,532**

The Company is required to receive an unqualified auditors' opinion in relation to the 2015 consolidated financial statements. The failure to receive an unqualified opinion is an event of default under the Credit Facility that must be cured within 30 days of such event or waived by the lenders under the Credit Facility. As discussed above, the report of the Company's independent registered public accounting firm that accompanies our audited consolidated financial statements for the year ended December 31, 2015 in this Annual Report on Form 10-K contains an explanatory paragraph regarding an event of default under the Credit Facility, a projected additional debt covenant violation, and resulting lack of liquidity, which raises substantial doubt about the Company's ability to continue as a going concern.

The Company has not received a waiver from the lenders under its Credit Facility for the explanatory paragraph to its 2015 independent registered public accounting firm report. As a result, the Company is in default under its Credit Facility and all of its debt is classified as current in the accompanying consolidated balance sheet as of December 31, 2015. A failure to cure this default within 30 days may result in the acceleration of all of the Company's indebtedness under the Credit Facility and, due to cross default and cross acceleration provisions, its other outstanding debt obligations.

Debt Restructuring

On May 21, 2015, the Company issued $625.0 million of Second Lien Notes and utilized the proceeds to repay the outstanding balance of the Credit Facility in an amount of approximately $468.2 million, with the remainder utilized for general corporate purposes. Further, the Company exchanged approximately $504.1 million of Third Lien Notes for approximately $279.8 million of 2020 Senior Notes and $350.3 million of 2021 Senior Notes, representing an exchange at 80.0% of the exchanged Unsecured Notes' par value. Additionally, on June 2, 2015, the Company exchanged approximately $20.0 million of Third Lien Notes for approximately $26.6 million of 2020 Senior Notes and $2.0 million of 2021 Senior Notes, representing an exchange at 70.0% of the exchanged Unsecured Notes' par value. Approximately $63.9 million of the principal amount of 2020 Senior Notes and $70.7 million of the principal amount of 2021 Senior Notes was extinguished.

Additionally, the Company and Midstates Sub entered into the Seventh Amendment to the Credit Facility (the "Seventh Amendment') which provided that upon completion of the offering of the Second Lien Notes and exchange of Third Lien Notes, the borrowing base of the Credit Facility would be reduced to $252.0 million. The Seventh Amendment also provided additional covenant flexibility. Further discussion regarding the Second Lien Notes, Third Lien Notes and Seventh Amendment can be found below. The exchanges of Third Lien Notes for the Unsecured Notes as well as the issuance of the Second Lien Notes were accounted for as a troubled debt restructuring. As the future cash flows of the modified debt instruments were greater than the carrying amount of the previous debt instruments, no debt extinguishment gain was recognized. The amount of extinguished debt will be amortized over the remaining life of the Second Lien Notes and Third Lien Notes using the effective interest method and recognized as a reduction of interest expense. As a result, the Company's reported interest expense will be significantly less than the contractual interest payments throughout the term of the Second Lien Notes and Third Lien Notes. All costs incurred related to the May 21, 2015 and June 2, 2015 exchanges, including restructuring costs as well as the direct issuance costs of the Second Lien Notes and Third Lien Notes, were expensed and are included within debt restructuring costs and advisory fees in the consolidated statements of operations.

The table below summarizes the changes in total debt, including debt classified as current, during the year as a result of the debt restructuring, not considering unamortized debt issuance costs related to the 2020 Senior Notes and the 2021 Senior Notes:

	December 31, 2014 Carrying Value	Borrowings/ (Repayments)	Exchanges	Deferred Gain on Forgiven Debt	Amortization of Forgiven Debt	Paid-in Kind Interest	December 31, 2015 Carrying Value (excluding unamortized debt issuance costs)
Credit Facility	$435,150	$(435,150)	$—	$—	$—	$—	$—
2020 Senior Notes	600,000	—	(242,445)	(63,930)	—	—	293,625
2021 Senior Notes	700,000	—	(281,676)	(70,672)	—	—	347,652
Second Lien Notes	—	625,000	—	47,082	(4,789)	—	667,293
Third Lien Notes	—	—	524,121	87,520	(10,159)	5,532	607,014
Total debt	**$1,735,150**	**$189,850**	**$—**	**$—**	**$(14,948)**	**$5,532**	**$1,915,584**

	December 31, 2015 Carrying Value	Unamortized Deferred Gain on Debt Forgiven	December 31, 2015 Principle Balance Outstanding
Credit Facility	$—	$—	$—
2020 Senior Notes	293,625	—	293,625
2021 Senior Notes	347,652	—	347,652
Second Lien Notes	667,293	(42,293)	625,000
Third Lien Notes	607,014	(77,361)	529,653
Total debt	**$1,915,584**	**$(119,654)**	**$1,795,930**

Reserve-based Credit Facility

The Company maintains a $750.0 million Credit Facility with a current borrowing base of $252.0. At December 31, 2015, the Company had no amounts drawn on the Credit Facility and had outstanding letters of credit obligations totaling $2.8 million. In February 2016, the Company borrowed approximately $249.2 million under the Credit Facility, which represented the remaining undrawn availability under the Credit Facility.

The Credit Facility matures on May 31, 2018 and borrowings thereunder are secured by substantially all of the Company's oil and natural gas properties and bear interest at LIBOR plus an applicable margin, depending upon the Company's borrowing base utilization, between 2.00% and 3.00% per annum.

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 0.500% 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 the Company or the administrative agent acting on behalf of lenders holding at least two-thirds of the outstanding loans and other obligations. On October 14, 2015, the Company and Midstates Sub entered into the Ninth Amendment, which, among other items, reaffirmed the borrowing base at $252.0 million. The next borrowing base redetermination is scheduled for April 2016.

Under the terms of the Credit Facility, the Company is required to repay any amount by which the principal balance of its outstanding loans and its letter of credit obligations exceeds its redetermined borrowing base or grant liens on additional property having sufficient value to eliminate such excess. The Company is 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. If commodity prices remain depressed or deteriorate further, the borrowing base under the Credit Facility will likely be reduced. Since the Credit Facility was fully drawn subsequent to December 31, 2015, any reduction in the borrowing base will result in a deficiency in the amount that the Company's borrowings exceed the borrowing base, which must be repaid within 30 days or in six equal monthly installments thereafter, at the Company's election. The Company may not have the financial resources to make any mandatory deficiency principal repayments, which could result in an event of default under the Credit Facility.

On March 24, 2015, the Company and Midstates Sub entered into a Sixth Amendment (the "Sixth Amendment") to the Credit Facility. The Sixth Amendment amended the required ratio of net consolidated indebtedness to EBITDA under the Credit Agreement for each of the fiscal quarters in 2015 from 4.0:1.0 to 4.5:1.0. Additionally, the Sixth Amendment amended the mortgage requirements under the Credit Facility to provide for an increase from 80.0% to 90.0% in the percentage of properties included in the borrowing base that are required to be subject to mortgages for the benefit of the lenders.

On May 21, 2015, the Company and Midstates Sub entered into a Seventh Amendment to the Credit Facility. The Seventh Amendment provided that, with the completion of the offering of the Second Lien Notes and exchange of the Third Lien Notes (both discussed below), the Company's borrowing base would be reduced to approximately $252.0 million. The Seventh Amendment also eliminated the required ratio of net consolidated indebtedness to EBITDA covenant and added a ratio of Total Senior Indebtedness (as defined therein) to EBITDA of not more than 1.0 to 1.0, which is further discussed below under "—Debt Covenants."

On August 5, 2015, the Company and Midstates Sub entered into an Eighth Amendment (the "Eighth Amendment") to the Credit Facility. The Eighth Amendment increased the limitation on certain leases and lease agreements into which Midstates and Midstates Sub may enter into during any period of twelve consecutive calendar months of the life of such leases from $2.0 million to $3.5 million.

On October 14, 2015, the Company and Midstates Sub entered into the Ninth Amendment to the Credit Facility (the "Ninth Amendment") which, among other items, reaffirmed the borrowing base at $252.0 million and provided flexibility for certain specified asset sales by confirming the amount of the borrowing base reduction if any such sale occurs.

2020 Senior Notes

On October 1, 2012, the Company issued $600.0 million in aggregate principal amount of 2020 Senior Notes, conducted pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act"). In October 2013, these notes were exchanged for an equal principal amount of identical registered notes. The 2020 Senior Notes rank pari passu in right of payment with the 2021 Senior Notes, the Second Lien Notes and Third Lien Notes; however, the 2021 Senior Notes and 2020 Senior Notes are effectively junior to the extent of the value of the collateral securing the Company's Credit Facility, the Second Lien Notes and the Third Lien Notes. The 2020 Senior Notes were co-issued on a joint and several basis by the Company and its wholly owned subsidiary, Midstates Sub. The Company does not have any operations or independent assets other than its 100% ownership interest in Midstates Sub and there are no other subsidiaries of the Company. The indenture governing the 2020 Senior Notes (the "2020 Senior Notes Indenture") does not impose any significant restrictions on the ability of Midstates Sub to transfer assets to, pay dividends to, make investments in or make loans to the Company or limit the ability of the Company to transfer assets to, pay dividends to, make investments in or make loans to Midstates Sub.

Upon the occurrence of certain change of control events, as defined in the 2020 Senior Notes Indenture, each holder of the 2020 Senior Notes will have the right to require that the Company repurchase all or a portion of such holder's 2020 Senior Notes in cash at a purchase price equal to 101.0% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

As part of the debt restructuring, on May 21, 2015 and June 2, 2015, a total of approximately $306.4 million aggregate principal amount of 2020 Senior Notes were exchanged for Third Lien Notes.

The estimated fair value of the 2020 Senior Notes as of December 31, 2015 was $35.2 million (Level 2 in the fair value measurement hierarchy), based on quoted market prices for these same debt securities. The effective interest rate was 11.2% and 11.1%, respectively, for the years ended December 31, 2015 and 2014.

2021 Senior Notes

On May 31, 2013, the Company issued $700.0 million in aggregate principal amount of 2021 Senior Notes. In October 2013, these notes were exchanged for an equal principal amount of identical registered notes. The 2021 Senior Notes rank pari passu in right of payment with the 2020 Senior Notes, Second Lien Notes and Third Lien Notes; however, the 2021 Senior Notes and 2020 Senior Notes are effectively junior to the extent of the value of the collateral securing the Company's secured indebtedness, including the Second Lien Notes and the Third Lien Notes. The 2021 Senior Notes were co-issued on a joint and several basis by the Company and its wholly owned subsidiary, Midstates Sub. The Company does not have any operations or independent assets other than its 100% ownership interest in Midstates Sub and there are no other subsidiaries of the Company. The indenture governing the 2021 Senior Notes (the "2021 Senior Notes Indenture") does not impose any significant restrictions on the ability of Midstates Sub to transfer assets to, pay dividends to, make investments in or make loans to the Company or limit the ability of the Company to transfer assets to, pay dividends to, make investments in or make loans to Midstates Sub.

Upon the occurrence of certain change of control events, as defined in the 2021 Senior Notes Indenture, each holder of the 2021 Senior Notes will have the right to require that the Company repurchase all or a portion of such holder's 2021 Senior Notes in cash at a purchase price equal to 101.0% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

As part of the debt restructuring, on May 21, 2015 and June 2, 2015, a total of approximately $352.3 million aggregate principal amount of 2021 Senior Notes were exchanged for Third Lien Notes.

The estimated fair value as of December 31, 2015 of the 2021 Senior Notes was $41.7 million (Level 2 in the fair value measurement hierarchy), based on quoted market prices for these same debt securities. The effective interest rate was 9.6% for the years ended December 31, 2015 and 2014.

Second Lien Notes

On May 21, 2015, the Company and Midstates Sub issued and sold $625.0 million aggregate principal amount of Second Lien Notes, in a private placement conducted pursuant to Rule 144A under the Securities Act. In November 2015, these notes were exchanged for an equal principal amount of identical registered notes. The Second Lien Notes mature on the earlier of June 1, 2020 or 12 months after the maturity date of the Company's Credit Facility (including any extension or refinancing of such facility). The Second Lien Notes have an interest rate of 10.0% and interest is payable semi-annually on June 1 and December 1 of each fiscal year. The Second Lien Notes are unconditionally guaranteed, jointly and severally, on a senior secured basis by each of the Company's future restricted subsidiaries (the "Guarantors") and will be initially secured by second-priority liens on substantially all of the Company's and Guarantors' assets that secure the Company's Credit Facility. The indenture governing the Second Lien Notes (the "Second Lien Notes Indenture") does not impose any significant restrictions on the ability of Midstates Sub to transfer assets to, pay dividends to, make investments in or make loans to the Company or limit the ability of the Company to transfer assets to, pay dividends to, make investments in or make loans to Midstates Sub.

The Second Lien Notes are senior secured obligations of the Company and rank effectively junior to its obligations under the Credit Facility, effectively senior to its existing and future unsecured indebtedness, effectively senior to the Company's Third Lien Notes and all future junior lien obligations, effectively junior to all existing and future secured indebtedness secured by assets not constituting collateral under the Second Lien Notes, pari passu with all of the Company's existing and future senior debt, structurally subordinated to all existing and future indebtedness of any non-Guarantor subsidiaries and senior to any existing or future subordinated debt.

Upon the occurrence of certain change of control events, as defined in the indenture governing the Second Lien Notes, each holder of the Second Lien Notes will have the right to require that the Company repurchase all or a portion of such holder's 2020 Second Lien Notes in cash at a purchase price equal to 101.0% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

The estimated fair value of the Second Lien Notes was $262.5 million as of December 31, 2015 (Level 2 in the fair value measurement hierarchy), based on quoted market prices for these same debt securities. The effective interest rate was 10.5% for the year ended December 31, 2015.

Third Lien Notes

On May 21, 2015 and June 2, 2015, the Company issued approximately $504.1 million and $20.0 million, respectively, in aggregate principal amount of Third Lien Notes in a private placement and in exchange for an aggregate $306.4 million of the 2020 Senior Notes and $352.3 million of the 2021 Senior Notes. In November 2015, these notes were exchanged for an equal principal amount of identical registered notes. The Third Lien Notes are unconditionally guaranteed, jointly and severally, on a senior secured basis by each of the Guarantors. The Third Lien Notes are secured by third-priority liens on substantially all of the Company's assets that secure the Credit Facility. The Third Lien Notes have an interest rate of 12.0%, consisting of cash interest of 10.0% and paid-in-kind interest of 2.0%, per annum and mature on the earlier of June 1, 2020 or 12 months after the maturity date of the Company's Credit Facility (including any extension or refinancing of such facility). Cash interest is payable semi-annually on June 1 and December 1 of each fiscal year. Paid-in-kind interest, which is included in other long-term liabilities in our consolidated balance sheet, increases the outstanding principal balance of the Third Lien Notes on June 1 and December 1 of each fiscal year. The indenture governing the Third Lien Notes (the "Third Lien Notes Indenture") does not impose any significant restrictions on the ability of Midstates Sub to transfer assets to, pay dividends to, make investments in or make loans to the Company or limit the ability of the Company to transfer assets to, pay dividends to, make investments in or make loans to Midstates Sub.

The Third Lien Notes are senior secured obligations of the Company and rank effectively junior to its obligations under the Credit Facility and Second Lien Notes to the extent of the value of the collateral securing such indebtedness, effectively senior to its existing and future unsecured indebtedness to the extent of the value of the collateral securing the Third Lien Notes, effectively senior to all future junior lien obligations that rank below a third-priority basis to the extent of the value of the collateral securing the Third Lien Notes, effectively junior to all existing and future secured indebtedness secured by assets not constituting collateral under the Third Lien Notes, pari passu to all of the Company's existing and future senior debt, structurally subordinated to all existing and future indebtedness of any non-Guarantor subsidiaries and senior in right of payment to any existing or future subordinated debt.

Upon the occurrence of certain change of control events, as defined in the indenture governing the Third Lien Notes, each holder of the Third Lien Notes will have the right to require that the Company repurchase all or a portion of such holder's Third Lien Notes in cash at a purchase price equal to 101.0% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

The estimated fair value of the Third Lien Notes was $94.3 million as of December 31, 2015 (Level 2 in the fair value measurement hierarchy), based on quoted market prices for these same debt securities. The effective interest rate was 12.6% for the year ended December 31, 2015.

Debt Covenants

The Credit Facility, as amended, contains, among other standard affirmative and negative covenants, financial covenants including a maximum ratio of Total Senior Indebtedness to EBITDA (as defined therein) of not more than 1.0 to 1.0 and a minimum current ratio (as defined therein) of not less than 1.0 to 1.0. The Credit Facility also limits the Company's ability to make any dividends, distributions or redemptions.

The indentures governing the 2020 Senior Notes, 2021 Senior Notes, Second Lien Notes and Third Lien Notes contain covenants that, among other things, restrict the Company's 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 the Company's affiliates; (vii) consolidate, merge or sell substantially all of the Company's assets; (viii) prepay, redeem or repurchase certain debt; (ix) alter the business the Company conducts; and (x) enter into agreements restricting the ability of the Company's current and any future subsidiaries to pay dividends.

10. Preferred Stock

Series A Preferred Stock

On October 1, 2012, the Company issued 325,000 shares of Series A Mandatorily Convertible Preferred Stock ("Series A Preferred Stock") with an initial liquidation preference of $1,000 per share and an 8.0% per annum dividend, payable semiannually at the Company's option in cash or through an increase in the liquidation preference. The Series A Preferred Shares were mandatorily convertible at September 30, 2015 into shares of the Company's common stock at a conversion price of $110.00 per share, which was automatically adjusted to reflect the reverse stock split. Based on the liquidation preference at September 30, 2015, each Series A Preferred Share converted into approximately 11.5 shares of the Company's common stock pursuant to the Certificate of Designation, which governed the Series A Preferred Stock. As a result, the Company issued 3,738,424 additional shares of common stock upon conversion of the Series A Preferred Stock.

For the year ended December 31, 2014, the $10.4 million Series A Preferred Stock dividend was based upon the estimated fair value of 265,979 common shares that would have been issued had the notional dividend amounts for the year of $29.3 million been converted into common shares at a conversion price of $110.00 per share

For the year ended December 31, 2013, the $15.6 million Series A Preferred Stock dividend was based upon the estimated fair value of 245,912 common shares that would have been issued had the notional dividend amounts for the year of $27.1 million been converted into common shares at a conversion price of $110.00 per share.

Share Activity

The following table summarizes changes in the number of Series A Preferred Stock shares since January 1, 2012:

	Series A Preferred Stock
Share count as of January 1, 2012	—
Issuance of preferred stock as consideration in Eagle Property Acquisition	325,000
Share count as of December 31, 2012	**325,000**
Share count as of December 31, 2013	**325,000**
Share count as of December 31, 2014	**325,000**
Conversion of preferred stock into common stock	(325,000)
Share count as of December 31, 2015	—

11. Equity and Share-Based Compensation

Common Shares

At December 31, 2015, the Company had 10,962,105 and 10,865,814 shares of its common stock issued and outstanding, respectively.

On April 25, 2012, the Company completed its initial public offering of common stock pursuant to a registration statement on Form S-1 (File 333-177966), as amended and declared effective by the SEC on April 19, 2012. Pursuant to the registration statement, the Company registered the offer and sale of 2,760,000 shares of $0.01 par value common stock, which included 600,000 shares of stock sold by the selling shareholders and 360,000 shares of common stock sold by the selling stockholders pursuant to an option granted to the underwriters to cover over-allotments.

On August 3, 2015, the Company completed a 1-for-10 reverse stock split of its outstanding common stock. To effect the reverse stock split, the Company filed a Certificate of Amendment to the Company's Restated Certificate of Incorporation, which provides for the reverse stock split and for the corresponding reduction in the Company's authorized capital stock to 100 million shares of common stock, $0.01 par value per share, following the reverse stock split.

The Company is also authorized to issue up to a total of 50,000,000 shares of its preferred stock with a par value of $0.01 per share. Holders of the Company's common shares are entitled to one vote for each share held of record on all matters submitted to a vote of stockholders and to receive ratably in proportion to the shares of common stock held by them any dividends declared from time to time by the board of directors. The common shares have no preferences or rights of conversion, exchange, pre-exemption or other subscription rights.

With respect to preferred shares, the Company is authorized, without further stockholder approval, to establish and issue from time to time one or more classes or series of preferred stock with such powers, preferences, rights, qualifications, limitations and restrictions as determined by its board of directors. See discussion of Series A Preferred Shares in "—Note 10. Preferred Stock".

Share Activity

The following table summarizes changes in the number of shares of common stock and treasury stock outstanding since January 1, 2013:

	Common Stock	Treasury Stock(1)
Share count as of January 1, 2013	**6,661,971**	—
Grants of restricted stock	284,024	—
Forfeitures of restricted stock	(53,421)	—
Acquisition of treasury stock	—	(11,870)
Share count as of December 31, 2013	**6,892,574**	**(11,870)**
Grants of restricted stock	344,748	—
Forfeitures of restricted stock	(188,149)	—
Acquisition of treasury stock	—	(41,597)
Share count as of December 31, 2014	**7,049,173**	**(53,467)**
Grants of restricted stock	268,677	—
Forfeitures of restricted stock	(94,159)	—
Acquisition of treasury stock	—	(42,824)
Fractional share adjustment due to reverse stock split	(10)	—
Issuance of common stock for Series A Preferred Stock conversion	3,738,424	—
Share count as of December 31, 2015	**10,962,105**	**(96,291)**

(1) Treasury stock represents the net settlement on vesting of restricted stock necessary to satisify the minimum statutory withholding requirements.

Incentive Units.

In connection with the corporate reorganization that occurred immediately prior to our initial public offering, incentive units held in the Company were contributed to FR Midstates Interholding, LP ("FRMI") in exchange for incentive units in FRMI. Holders of FRMI incentive units will receive, out of proceeds otherwise distributable to FRMI, a percentage interest in the amounts distributed to FRMI in excess of certain multiples of FRMI's aggregate capital contributions and investment expenses ("FRMI Profits"). Although any future payments to the incentive unit holders will be made out of the proceeds otherwise distributable to FRMI and not by the Company, the Company will be required to record a non-cash compensation charge in the period any payment is made related to the FRMI incentive units. To date, no compensation expense related to the incentive units has been recognized by the Company, as any payout under the incentive units is not considered probable, and thus, the amount of FRMI Profits, if any, cannot be determined.

Share-based Compensation

2012 Long Term Incentive Plan.

On April 20, 2012, the Company established the 2012 Long Term Incentive Plan (the "2012 LTIP") and filed a Form S-8 with the SEC, registering 656,343 shares of common stock for future issuance under the terms of the 2012 LTIP. On May 27, 2014, the Company filed a Form S-8 with the SEC, increasing the number of shares available for future issuance under the terms of the 2012 LTIP to 863,843 shares of common stock.

The 2012 LTIP provides a means for the Company to attract and retain employees, directors and consultants, and a method whereby employees, directors and consultants of the Company who contribute to its success can acquire and maintain stock ownership or awards, the value of which is tied to the performance of the Company.

The 2012 LTIP provides for the granting of Options (Incentive and other), Restricted Stock Awards, Restricted Stock Units, Stock Appreciation Rights, Dividend Equivalents, Bonus Stock, Other Stock-Based Awards, Annual Incentive Awards, Performance Awards, or any combination of the foregoing (the "Awards"). Subject to certain limitations as defined in the 2012 LTIP, the terms of each Award are as determined by the Compensation Committee of the Board of Directors. As of December 31, 2015, a total of 863,843 common share Awards are authorized for issuance under the 2012 LTIP and shares of stock subject to an Award that expire, or are canceled, forfeited, exchanged, settled in cash or otherwise terminated, will again be available for future Awards under the 2012 LTIP.

Non-vested Stock Awards.

At December 31, 2015 the Company had 318,031 shares of restricted common stock outstanding pursuant to the 2012 LTIP. Shares granted under the LTIP generally vest ratably over a period of three years (one-third on each anniversary of the grant), however, beginning in 2013, shares granted under the 2012 LTIP to directors are subject to one-year cliff vesting.

The fair value of restricted stock grants is based on the value of the Company's common stock on the date of grant. Compensation expense is recognized ratably over the requisite three year service period.

The following table summarizes the Company's non-vested share award activity for the years ended December 31, 2015, 2014 and 2013:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2012	**98,535**	$126.13
Granted	284,024	$68.23
Vested	(32,772)	$126.18
Forfeited	(53,420)	$86.46
Non-vested shares outstanding at December 31, 2013	**296,367**	$77.78
Granted	344,748	$46.60
Vested	(146,764)	$72.08
Forfeited	(188,149)	$65.83
Non-vested shares outstanding at December 31, 2014	**306,202**	$52.76
Granted	268,677	$12.29
Vested	(162,689)	$54.39
Forfeited	(94,159)	$38.69
Non-vested shares outstanding at December 31, 2015	**318,031**	$21.46

Unrecognized expense as of December 31, 2015 for all outstanding restricted stock awards, adjusted for estimated forfeitures, was $3.8 million and will be recognized over a weighted average period of 1.53 years.

At December 31, 2015, 203,589 shares remain available for issuance under the terms of the 2012 LTIP.

The share-based compensation costs (net of amounts capitalized to oil and gas properties) recognized as general and administrative expense by the Company for the years ended December 31, 2015, 2014, and 2013 of $4.4 million, $8.6 million, and $5.7 million, respectively, all related to the 2012 LTIP.

During the quarter ended December 31, 2014, the Company announced that its corporate headquarters was relocating from Houston, Texas to Tulsa, Oklahoma, which resulted in the accelerated vesting of restricted stock awards in the period for Houston employees subject to a severance agreement. Of the $4.4 million in share-based compensation for the twelve months ended December 31, 2015, approximately $1.5 million was related to the accelerated vesting for employees impacted by the corporate relocation. For the twelve months ended December 31, 2014, approximately $2.9 million of the $8.6 million in share-based compensation was related to the accelerated vesting.

For the years ended December 31, 2015 and 2014, the Company capitalized $1.3 million and $2.2 million, respectively, of qualifying share-based compensation costs to oil and gas properties.

12. Income Taxes

The Company incurred a tax net operating loss ("NOL") in the current year. There is no tax refund available to the Company, nor is there any current income tax payable. In light of the impairment of oil and gas properties recorded in the current year, management recorded a $689.4 million valuation allowance against the Company's federal and state NOLs this year. Management believes that the balance of the Company's NOLs are realizable only to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment. The Company reported unrealized losses from hedging activities in the amount of $126.7 million and impairments of oil and gas properties in the amount of $1.6 billion, which resulted in pre-tax book loss of $1.8 billion for the year ended December 31, 2015.

The Company's NOLs were incurred in the tax years 2012 through 2015, and U.S. federal and State of Oklahoma NOLs will generally be available for use through the tax years 2033 and 2035, respectively, and its State of Louisiana NOLs are generally available through 2028 and 2030, respectively. The State of Texas currently has no NOL carryover provision. Section 382 of the Internal Revenue Code of 1986, as amended, relates to tax attribute limitations upon the 50% or greater change of ownership of an entity during any three year look back period. The Company believes there has not been such a change as of December 31, 2015.

As of December 31, 2015, the Company has not recorded a reserve for any uncertain tax positions. The Company believes that there are no new items, nor changes in facts or judgments that should impact the Company's tax position. No federal income tax payments are expected in the upcoming four quarterly reporting periods.

	For the Years Ended December 31,		
	2015	**2014**	**2013**
	(in thousands)		
Current			
United States	$—	$—	$—
State	—	809	—
Total current	—	809	—
Deferred			
United States	(3,864)	3,863	(130,906)
State	(5,777)	1,723	(15,623)
Total deferred	(9,641)	5,586	(146,529)
Total income tax provision (benefit)	**$(9,641)**	**$6,395**	**$(146,529)**

The Company's estimated income tax expense differs from the amount derived by applying the statutory federal rate to pretax income principally due the effect of the following items:

	Years Ended December, 31		
	2015	**2014**	**2013**
	(in thousands)		
Income (loss) before taxes	$(1,806,836)	$123,324	$(490,514)
Statutory rate	35%	35%	35%
Income tax provision (benefit) computed at statutory rate	(632,393)	43,164	(171,680)
Reconciling items:			
State income taxes, net of federal benefit	(65,904)	4,398	(10,886)
Change in valuation allowance	689,419	(42,134)	45,688
Change in state rate	(612)	(414)	(10,500)
Other, net	(151)	1,381	849
Total income tax provision (benefit)	**$(9,641)**	**$6,395**	**$(146,529)**

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of our deferred taxes are detailed in the table below:

	Years Ended December 31,	
	2015	**2014**
	(in thousands)	
Deferred tax assets—current		
Derivative instruments and other	$—	$—
Less valuation allowance	—	—
Total deferred tax assets, current	**$—**	**$—**
Deferred tax assets—noncurrent		
Federal tax loss carryforwards	146,641	75,604
State tax loss carryforwards	13,848	7,122
Employee benefit plans	1,160	2,193
Oil and gas properties and equipment	465,028	—
Debt restructuring	66,693	—
Less valuation allowance	(693,370)	(3,826)
Total deferred tax assets, noncurrent	**$—**	**$81,093**

	Years Ended December 31,	
	2015	2014
	(in thousands)	
Deferred tax liabilities—current		
Derivative instruments and other	—	44,862
Total deferred tax liabilities—current	**$—**	**$44,862**
Deferred tax liabilities—noncurrent		
Oil and gas properties and equipment	—	45,272
Total deferred tax liabilities, noncurrent	**$—**	**$45,272**
Reflected in the accompanying balance sheet as:		
Net deferred tax asset, current	**$—**	**$—**
Net deferred tax liability, current	**$—**	**$44,862**
Net deferred tax asset, noncurrent	**$—**	**$35,821**
Net deferred tax liability, noncurrent	**$—**	**$—**

13. Earnings (Loss) Per Share

The Company's Series A Preferred Stock issued in connection with the Eagle Property Acquisition, which converted into common stock on September 30, 2015, had the nonforfeitable right to participate on an as converted basis at the conversion rate then in effect in any common stock dividends declared and as such, was considered a participating security. The Company's nonvested stock awards, which are granted as part of the 2012 LTIP, contain nonforfeitable rights to dividends and as such, are considered to be participating securities and, together with the Series A Preferred Stock, are included in the computation of basic and diluted earnings (loss) per share, pursuant to the two-class method. In the calculation of basic earnings (loss) per share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so.

The computation of diluted earnings (loss) per share attributable to common shareholders reflects the potential dilution that could occur if securities or other contracts to issue common shares that are dilutive were exercised or converted into common shares (or resulted in the issuance of common shares) and would then share in the earnings of the Company. During the periods in which the Company records a loss from continuing operations attributable to common shareholders, securities would not be dilutive to net loss per share and conversion into common shares is assumed to not occur. Diluted net income per share attributable to common shareholders is calculated under both the two- class method and the treasury stock method; the more dilutive of the two calculations is presented below.

The following table provides a reconciliation of net income (loss) to preferred shareholders, common shareholders, and participating securities for purposes of computing net income (loss) per share:

	Years Ended December 31,		
	2015	2014	2013
	(in thousands, except per share amounts)		
Net income (loss)	$(1,797,195)	$116,929	$(343,985)
Preferred Dividend(1)	(948)	(10,378)	(15,589)
Net income (loss) attributable to shareholders	**$(1,798,143)**	**$106,551**	**$(359,574)**
Participating securities—Series A Preferred Stock(2)	—	(35,696)	—
Participating securities—Non-vested Restricted Stock(2)	—	(3,584)	—
Net income (loss) attributable to common shareholders	**$(1,798,143)**	**$67,271**	**$(359,574)**
Weighted average shares outstanding	**7,726**	**6,644**	**6,576**
Basic and diluted net income (loss) per share	**$(232.74)**	**$10.13**	**$(54.68)**

(1) Calculation of the preferred stock dividend is discussed in "—Note 10. Preferred Stock".

(2) As these shares are participating securities that participate in earnings, but are not required to participate in losses, this calculation demonstrates that there is not an allocation of the loss to the non-vested restricted stockholders.

14. Concentrations of Credit Risk

Financial instruments which potentially subject the Company to credit risk consist primarily of cash balances, accounts receivable and, historically, derivative financial instruments.

The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments.

The Company normally sells production to a relatively small number of purchasers, as is customary in the exploration, development and production business. The Company typically sells a substantial portion of production under short-term (usually one month) contracts tied to a local index. The Company does not have any long-term, fixed-price sales contracts. For the year ended December 31, 2015, two purchasers accounted for 43% and 25%, respectively, of the Company's revenue. For the year ended December 31, 2014, four purchasers accounted for 28%, 18%, 15% and 12% respectively, of the Company's revenue. For the year ended December 31, 2013, five purchasers accounted for 28%, 16%, 13%, 12% and 11% respectively, of the Company's revenue.

Substantially all of the Company's accounts receivable result from the sale of oil, natural gas and natural gas liquids. At December 31, 2015, three purchasers accounted for approximately 33%, 29%, and 14%, respectively, of the accounts receivable balance. At December 31, 2014, four purchasers accounted for approximately 25%, 23%, 15% and 13% respectively, of the accounts receivable balance.

Derivative financial instruments are generally executed with major financial institutions that expose the Company to market and credit risks and which may, at times, be concentrated with certain counterparties. The credit worthiness of the counterparties is subject to continual review. The Company also has netting arrangements in place with counterparties to reduce credit exposure. The Company has not experienced any losses from such instruments and has no derivative instruments in place at December 31, 2015.

15. Commitments and Contingencies

Contractual Obligations

At December 31, 2015, contractual obligations for drilling contracts, long-term operating leases, seismic contracts and other contracts are as follows (in thousands):

	Total	2016	2017	2018	2019	2020 and beyond
Drilling contracts	$3,468	$3,468	$—	$—	$—	$—
Non-cancellable office lease commitments(1)	7,463	1,877	1,941	1,471	966	1,208
Seismic contracts	3,192	3,192	—	—	—	—
Net minimum commitments	**$14,123**	**$8,537**	**$1,941**	**$1,471**	**$966**	**$1,208**

(1) During 2014, the Company announced plans to relocate the headquarters from Houston, Texas to Tulsa, Oklahoma. However, at December 31, 2015, the Company still leased space in Houston (with a contractual obligation through 2018) and of the $7.5 million total in office lease commitments, approximately $2.5 million relates to the Houston leases.

For the years ended December 31, 2015, 2014, and 2013, the Company expensed $2.3 million, $2.3 million, and $1.7 million, respectively, for office rent.

In addition to the commitments noted in the above table, the Company is 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). We are currently delivering at least the minimum volumes required under these contractual provisions. However, decreased drilling activity could result in the inability to meet these commitments in the future.

Commitments related to ARO's are not included in the table above. For additional information, please see "—Note 8. Asset Retirement Obligations" for discussion of those commitments.

Litigation

The Company is involved in various matters incidental to its operations and business that might give rise to a loss contingency. These matters may include legal and regulatory proceedings, commercial disputes, claims from royalty, working interest and surface owners, property damage and personal injury claims and environmental authorities or other matters. In addition, the Company may be subject to customary audits by governmental authorities regarding the payment and reporting of various taxes, governmental royalties and fees as well as compliance with unclaimed property (escheatment) requirements and other laws. Further, other parties with an interest in wells operated by the Company have the ability under various contractual agreements to perform audits of its joint interest billing practices.

The Company vigorously defends itself in these matters. If the Company determines that an unfavorable outcome or loss of a particular matter is probable and the amount of loss can be reasonably estimated, it accrues a liability for the contingent obligation. As new information becomes available or as a result of legal or administrative rulings in similar matters or a change in applicable law, the Company's conclusions regarding the probability of outcomes and the amount of estimated loss, if any, may change. The impact of subsequent changes to the Company's accruals could have a material effect on its results of operations. As of December 31, 2015 and 2014, the Company's total accrual for all loss contingencies was $1.0 million and $0.2 million, respectively.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

The supplemental data presented herein reflects information for all of the Company's oil and natural gas producing activities.

Capitalized Costs

The following table sets forth the capitalized costs related to the Company's oil and natural gas producing activities at December 31, 2015 and 2014:

	December 31, 2015	December 31, 2014
	(in thousands)	
Proved properties	$3,666,403	$3,398,146
Less: Accumulated depreciation, depletion, amortization and impairment	(3,148,240)	(1,326,972)
Proved Properties, net	518,163	2,071,174
Unproved properties	—	44,535
Total oil and gas properties, net	**$518,163**	**$2,115,709**

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

The following table sets forth costs incurred related to the Company's oil and natural gas activities for the years ended December 31, 2015, 2014 and 2013:

	For the Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Acquisition costs:			
Proved properties	$—	$—	$413,472
Unproved properties	8,448	25,576	206,339
Exploration costs	—	672	9,554
Development costs	274,978	525,941	595,785
Total costs incurred	**$283,426**	**$552,189**	**$1,225,150**

Costs incurred in the tables above include additions and revisions to the Company's asset retirement obligations.

Costs Not Being Amortized

At December 31, 2015, the Company had no oil and gas property costs that are not being amortized. During 2015, as a result of current oil and gas prices, its anticipated drilling plans and uncertainty regarding its ability to finance its exploration activities, the Company transferred the remaining unevaluated property balance, consisting of $56.3 million of Mississippian unevaluated property costs, $0.2 million of Anadarko Basin unevaluated property costs and $0.1 million of Gulf Coast unevaluated property costs to the full cost pool.

Estimated Quantities of Proved Oil and Natural Gas Reserves

The reserve estimates at December 31, 2014 and 2013 for the Gulf Coast area and at December 31, 2014 for the Mississippian Lime area were based on a report prepared by Netherland, Sewell and Associates, Inc., independent reserve engineers, in accordance with the FASB’s authoritative guidance on oil and gas reserve estimation and disclosures. The reserve estimates at December 31, 2015 for the Mississippian Lime and Anadarko Basin areas and at December 31, 2014 for the Anadarko Basin area were based on reports prepared by Cawley Gillespie & Associates, Inc., independent reserve engineers, in accordance with the FASB’s authoritative guidance on oil and gas reserve estimation and disclosures.

The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made.

The following table sets forth the Company’s net proved, proved developed and proved undeveloped reserves at December 31, 2015, 2014 and 2013:

	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Total (MBoe)
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**
2015				
Proved Reserves				
Beginning Balance	58,242	32,528	377,845	153,744
Revision of previous estimates	(30,490)	(15,495)	(178,287)	(75,700)
Extensions, discoveries and other additions	2,189	1,371	17,026	6,398
Sales of reserves in place	(2,871)	(843)	(7,834)	(5,019)
Purchases of reserves in place	2,437	1,157	15,145	6,118
Production	(4,794)	(2,473)	(28,403)	(12,001)
Net proved reserves at December 31, 2015	**24,713**	**16,245**	**195,492**	**73,540**
Proved developed reserves, December 31, 2015	**23,006**	**15,376**	**184,365**	**69,110**
Proved undeveloped reserves, December 31, 2015	**1,707**	**869**	**11,127**	**4,430**

Purchases of Reserves in Place

In 2015, the Company had 6,118 MBoe of additions from purchases of reserves in place resulting from a swap of leasehold interests in the Mississippian area in the second quarter of 2015. The Company had no additions from purchases of reserves in 2014. In 2013, the Company had a total of 37,642 MBoe of additions from purchases of reserves in place primarily as a result of the Anadarko Basin Acquisition, which closed on May 31, 2013. The acquired assets included interests in producing oil and natural gas assets and leasehold acreage in Texas and Oklahoma.

Extensions, Discoveries and Other Additions

In 2015 and 2014, the Company had a total of 6,398 MBoe and 77,035 MBoe, respectively, of additions from extensions and discoveries, all of which related to the Mississippian area. In 2013, the Company had a total of 43,608 MBoe of additions from extensions and discoveries, with approximately 34,300 MBoe related to the Mississippian area and the remaining 9,300 MBoe related to the Anadarko Basin and Gulf Coast areas.

Sales of Reserves in Place

In 2015, the Company had 5,019 MBoe in sales of reserves in place, of which 2,307 MBoe of the sale related to the Dequincy Divestiture, which closed on April 21, 2015 and 2,712 MBoe resulted from the swap of leasehold interests in the Mississippian area in the second quarter of 2015. In 2014, the Company had 16,391 MBoe in sales of reserves in place related to the Pine Prairie Disposition, which closed on May 1, 2014. There were no sales of reserves during 2013.

Revision of Previous Estimates

In 2015, the Company had net negative revisions of 75,700 MBoe related to proved undeveloped reserves, of which approximately 98% related to reductions in the Mississippian area due to the transfer of 77,362 MBoe of proved undeveloped reserves comprising $179.0 million of PV-10 value (at SEC pricing) to the probable reserve category due to uncertainty around financing the development of our proved undeveloped reserves within a five year period.

In 2014, the Company had net negative revisions of 22,925 MBoe related to proved undeveloped reserves, of which 3,084 MBoe related to reductions in our Gulf Coast area, and 22,138 MBoe related to reductions in our Anadarko Basin area, partially offset by 2,297 MBoe 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 2013, the Company had net negative revisions of 20,230 MBoe, of which approximately 17,800 MBoe related to the Gulf Coast. Of these revisions in the Gulf Coast, approximately 9,500 MBoe related to Pine Prairie and were driven by higher development and lease operating costs which resulted in certain proved undeveloped locations becoming uneconomic as of December 31, 2013, and approximately 4,900 MBoe related to West Gordon, primarily due to poor drilling results.

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

The standardized measure represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows. Production costs do not include depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

Our estimated proved reserves and related future net revenues and standardized measure were determined using the unweighted arithmetic average first-of-the-month price for the preceding 12-month period, without giving effect to derivative transactions, and were held constant throughout the life of the properties. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. The following table sets forth the benchmark prices used to determine our estimated proved reserves for the periods indicated:

	At December 31,		
	2015	2014	2013
Oil and Natural Gas Prices:			
Oil (per barrel)	$50.28	$94.99	$97.18
NGL (per barrel)	$17.44	$39.17	$36.36
Natural gas (per million British thermal units)	$2.59	$4.35	$3.28

The following table sets forth the Standardized Measure of discounted future net cash flows from projected production of the Company's oil and natural gas reserves at December 31, 2015, 2014, and 2013.

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Future cash inflows	$1,902,184	$8,405,916	$7,206,900
Future production costs	(1,024,314)	(2,669,000)	(2,356,495)
Future development costs	(47,532)	(751,353)	(1,253,144)
Future income tax expense	—	(1,113,908)	(510,400)
Future net cash flows	830,338	3,871,655	3,086,861
10% annual discount for estimated timing of cash flows	(317,519)	(1,998,294)	(1,296,415)
Standardized measure of discounted future net cash flows	**$512,819**	**$1,873,361**	**$1,790,446**

The following table sets forth the changes in the standardized measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the periods presented.

	Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
January 1	$1,873,361	$1,790,446	$1,149,474
Net changes in prices and production costs	(960,245)	(190,256)	(83,055)
Net changes in future development costs	57,357	66,828	49,170
Sales of oil and natural gas, net	(232,630)	(536,362)	(411,953)
Extensions	38,550	1,094,606	579,945
Discoveries	—	—	—
Purchases of reserves in place	34,369	—	603,695
Divestiture of reserves	(77,445)	(390,264)	—
Revisions of previous quantity estimates	(1,174,997)	(205,233)	(399,210)
Previously estimated development costs incurred	198,564	160,663	139,377
Accretion of discount	238,639	206,783	148,909
Net change in income taxes	513,024	(230,401)	54,326
Changes in timing, other	4,272	106,551	(40,232)
Period end	**$512,819**	**$1,873,361**	**$1,790,446**

SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table presents selected quarterly financial data derived from the Company's unaudited interim financial statements. The following data is only a summary and should be read with the Company's historical consolidated financial statements and related notes contained in this document.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts)			
2015				
Total revenues	$111,198	$74,754	$110,363	$68,830
Operating loss	(166,101)	(553,584)	(453,790)	(470,328)
Net loss	(193,554)	(598,437)	(494,342)	(510,862)
Net loss available to common shareholders	(193,685)	(599,106)	(494,490)	(510,862)
Net loss per share:				
Basic and Diluted	$(28.80)	$(88.44)	$(72.34)	$(48.48)
Shares used in computation:				
Basic and Diluted	6,726	6,774	6,835	10,537
2014				
Total revenues	$144,662	$147,990	$224,761	$276,770
Operating income (loss)	(51,978)	31,665	111,091	170,055
Net income (loss)	(83,645)	(2,098)	74,597	128,075
Net income (loss) available to common shareholders	(86,265)	(6,904)	46,192	80,626
Net income (loss) per share:				
Basic and Diluted	$(13.07)	$(1.04)	$6.94	$12.08
Shares used in computation:				
Basic and Diluted	6,598	6,645	6,659	6,673

EXHIBIT 12.1

MIDSTATES PETROLEUM COMPANY, INC.
RATIO OF EARNINGS TO FIXED CHARGES AND TO COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS
(In thousands, except ratios)

	Year Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Earnings available before fixed charges:					
Pre-tax income (loss)	$(1,806,836)	$123,324	$(490,514)	$7,789	$16,657
Interest expense	151,832	129,691	77,179	11,711	2,094
Amortization of capitalized interest	23,960	4,961	10,683	1,050	615
Loan cost amortization	11,316	7,857	5,960	1,529	850
Portion of rental expense which represents interest factor	699	698	497	340	179
Total earnings available for fixed charges	**$(1,619,029)**	**$266,531**	**$(396,195)**	**$22,419**	**$20,395**
Interest expense	$151,832	$129,691	$77,179	$11,711	$2,094
Capitalized interest	4,859	12,415	32,245	11,175	2,600
Loan cost amortization	11,316	7,857	5,960	1,529	850
Portion of rental expense which represents interest factor	699	698	497	340	179
Total fixed charges	**$168,706**	**$150,661**	**$115,881**	**$24,755**	**$5,723**
Ratio of earnings to fixed charges	**—**	**1.8x**	**—**	**—**	**3.6x**
Insufficient coverage	**$1,787,735**	**$—**	**$512,076**	**$2,336**	**$—**
Total fixed charges	$168,706	$150,661	$115,881	$24,755	$5,723
Pre-tax preferred dividends(1)	23,545	30,863	38,588	10,844	—
Total fixed charges plus preferred dividends	**$192,251**	**$181,524**	**$154,469**	**$35,599**	**$5,723**
Ratio of earnings to combined fixed charges and preferred dividends	**—**	**1.5x**	**—**	**—**	**3.6x**
Insufficient coverage	**$1,811,280**	**$—**	**$550,664**	**$13,180**	**$—**

(1) Prior to October 1, 2012, the Company did not have any preferred stock outstanding. Preferred dividends shown herein relate to the Company's Series A Mandatorily Convertible Preferred Stock ("Series A Preferred Stock") issued on October 1, 2012, which allows, at the Company's option, for the 8% annual dividend payment to be made either in cash or through an adjustment to the Series A Preferred Stock liquidation preference. Pre-tax preferred stock dividend amounts for the years ended December 31, 2015, 2014, 2013 and 2012 were calculated utilizing the Company's effective tax rate for the applicable periods (0.5%, 5.2%, 29.9% and 40.1%, respectively) and represent the notional dividend amount as though paid in cash, rather than through an adjustment to the Series A Preferred Stock liquidation preference.

EXHIBIT 21.1

List of Subsidiaries of Midstates Petroleum Company, Inc.

Entity	State of Formation
Midstates Petroleum Company LLC	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-189499 on Form S-3 and Registration Statements Nos. 333-180854 and 333-196294 on Form S-8 of our report dated March 30, 2016, relating to the consolidated financial statements of Midstates Petroleum Company, Inc. and subsidiary (which report expresses an unqualified opinion and includes an explanatory paragraph regarding going concern uncertainty), appearing in this Annual Report on Form 10-K of Midstates Petroleum Company, Inc. and subsidiary for the year ended December 31, 2015.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 30, 2016

EXHIBIT 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our report as of December 31, 2014, included in the Annual Report on Form 10-K of Midstates Petroleum Company, Inc. for the fiscal year ended December 31, 2015, as well as in the notes to the financial statements included therein.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (SCOTT) REES III
Name: C.H. Scott Rees III, P.E.
Title: *Chairman and Chief Executive Officer*

Dallas, Texas
March 30, 2016

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Cawley, Gillespie & Associates, Inc., hereby consents to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our summary report dated March 1, 2016 included in the Annual Report on Form 10-K of Midstates Petroleum Company, Inc. for the fiscal year ended December 31, 2015, as well as in the notes to the financial statements included therein. We hereby further consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our summary report dated March 1, 2016, into Midstates Petroleum Company, Inc.'s previously filed Registration Statement No. 333-189499 on Form S-3 and Registration Statement No. 333-180854 and 333-196294 on Form S-8.

By: /s/ J. ZANE MEEKINS

Name: J. Zane Meekins

Title: *Executive Vice President*

Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693
Fort Worth, Texas
March 30, 2016

EXHIBIT 31.1

CERTIFICATION

I, Frederic F. Brace, certify that:

1. I have reviewed this Annual Report on Form 10-K for the period ending December 31, 2015 (the "report") of Midstates Petroleum Company, Inc. (the "registrant");

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

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

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

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

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 30, 2016

/s/ FREDERIC F. BRACE

Frederic F. Brace
Interim President and Chief Executive Officer (Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION

I, Nelson M. Haight, certify that:

1. I have reviewed this Annual Report on Form 10-K for the period ending December 31, 2015 (the "report") of Midstates Petroleum Company, Inc. (the "registrant");

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

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

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

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

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: March 30, 2016

/s/ NELSON M. HAIGHT

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

EXHIBIT 32.1

CERTIFICATION

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, Frederic F. Brace, Interim President and Chief Executive Officer of Midstates Petroleum Company, Inc. (the “Company”), certifies that, to his knowledge:

1. the Annual Report on Form 10-K of the Company for the period ending December 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 30, 2016

/s/ FREDERIC F. BRACE

Frederic F. Brace
Interim President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 32.2

CERTIFICATION

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, Nelson M. Haight, Executive Vice President and Chief Financial Officer of Midstates Petroleum Company, Inc. (the “Company”), certifies that, to his knowledge:

1. the Annual Report on Form 10-K of the Company for the period ending December 31, 2015, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 30, 2016

/s/ NELSON M. HAIGHT

Nelson M. Haight

Executive Vice President and Chief Financial Officer