Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2016

OR

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

For the transition period from to .
Commission File Number: 001-35512

MIDSTATES PETROLEUM COMPANY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**45-3691816**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
321 South Boston Avenue, Suite 1000 Tulsa, Oklahoma	**74103**
(Address of principal executive offices)	(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	**NYSE MKT**
(Title of each class)	(Name of each exchange on which registered)

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

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

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

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

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

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

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

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

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

The aggregate market value of the registrant's Common Stock held by non-affiliates of the registrant was approximately $1.2 million based upon the closing price of such stock on June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, of $0.15 per share.

The number of shares outstanding of our stock at March 27, 2017 is shown below:

Class	**Number of shares outstanding**
Common stock, $0.01 par value	24,994,867

DOCUMENTS INCORPORATED BY REFERENCE

None.

MIDSTATES PETROLEUM COMPANY, INC.
TABLE OF CONTENTS

Table of Contents

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 income/loss, 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, including our business strategy post-emergence from our Chapter 11 cases (the "Chapter 11 Cases");
- estimated future net reserves and present value thereof;
- technology;
- financial condition, revenues, cash flows and expenses;
- levels of indebtedness, liquidity, borrowing capacity 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;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability of oilfield labor;
- availability of third party natural gas gathering and processing capacity;
- 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;

Table of Contents

- the outcome of pending and future litigation;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in oil and natural gas producing countries;
- new capital structure and the adoption of fresh start accounting, including the risk that assumptions and factors used in estimating enterprise value vary significantly from the current estimates in connection with the application of fresh start accounting;
- 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 reserves based revolving credit facility (the "Exit 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, including future regulations regarding the disposal of salt water; 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.

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 reserves estimate depends on the quality of available data (including geoscience and engineering 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 future production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

Table of Contents

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 drill or 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 natural 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

Table of Contents

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, re-establishing, 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 oil and/or natural gas 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, natural 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

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. 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" or "Debtor Affiliate"). In this Annual Report, references to "Company," "we," "us," "our," and "Midstates" when used in the present tense, prospectively or for historical periods, refer to Midstates Petroleum Company, Inc. and its wholly owned subsidiary.

Our common stock was listed on the New York Stock Exchange (the "NYSE") on April 25, 2012 through February 3, 2016 under the symbol "MPO". On February 3, 2016, our stock was delisted by the NYSE and began trading on the OTC Pink market under the symbol "MPOY". On April 30, 2016, we filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code. On October 21, 2016, in connection with our emergence from Chapter 11, our existing common shares traded under the symbol MPOY were cancelled and on October 24, 2016, our new common shares issued in connection with our successful reorganization and emergence from Chapter 11 were listed and began trading on the NYSE MKT under the symbol "MPO". We currently lease 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 2026. We also lease one field office in Dacoma, Oklahoma and one in Perryton, Texas. As of December 31, 2016, we had 124 employees.

We are required to file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("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 South Boston Avenue, Suite 1000; Tulsa, Oklahoma 74103, attention Vice President General Counsel. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

Chapter 11 Plan of Reorganization

On April 30, 2016 (the "Petition Date"), we filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas (the "Bankruptcy Court"). Our Chapter 11 cases (the "Chapter 11 Cases") were jointly administered under the case styled *In re Midstates Petroleum*

Table of Contents

Company, Inc., et al., Case No. 16-32237. On September 28, 2016, the Bankruptcy Court entered the *Findings of Fact, Conclusions of Law, and Order Confirming Debtors' First Amended Joint Chapter 11 Plan of Reorganization of Midstates Petroleum Company, Inc. and its Debtor Affiliate* (the "Confirmation Order"), which approved and confirmed the First Amended Joint Chapter 11 Plan of Reorganization of Midstates Petroleum Company, Inc. and its Debtor Affiliate as filed on the same date (the "Plan"). On October 21, 2016 (the "Effective Date"), we satisfied the conditions to effectiveness set forth in the Confirmation Order and in the Plan, the Plan became effective in accordance with its terms and we emerged from the Chapter 11 Cases. Pursuant to the confirmed Plan, the significant transactions that occurred upon the Effective Date were as follows:

Substantial Deleveraging of the Balance Sheet: The permanent pay-down of $81.3 million of our revolving credit facility ("RBL"), with a $170.0 million Exit Facility established upon the Effective Date, (ii) the pay-down of $60.0 million of our Second Lien Notes in cash, and (iii) the conversion into equity of all of our remaining debt junior to the RBL;

Credit Facility Claims: Holders of allowed claims arising under the RBL (the "Credit Facility Claims") received their pro rata share of approximately $81.3 million in cash and the RBL was superseded, pursuant to the Plan, by the Exit Facility, as further described below;

Second Lien Notes Claims: Holders of allowed claims arising under the Second Lien Notes (the "Second Lien Notes Claims") received their pro rata share of (i) 96.25% of the reorganized equity in the form of common stock and (ii) a cash payment of $60.0 million;

Third Lien Notes Claims: Holders of allowed claims arising under the Third Lien Notes (the "Third Lien Notes Claims"), pursuant to a settlement with holders of Second Lien Notes Claims on terms more fully set forth in the Plan (the "Second/Third Lien Plan Settlement"), received their pro rata share of 2.5% of the reorganized equity in the form of common stock and warrants to acquire 4,411,765 shares of common stock at a strike price of $24.00 per common share with an expiration date 42 months after the Effective Date;

Unsecured Claims: Holders (the "Unsecured Noteholders") of allowed claims arising under the Debtors' 10.75% Senior Unsecured Notes due 2020 (the "2020 Notes Claims"), the holders of allowed claims arising under the 9.25% Senior Unsecured Notes due 2021 (the "2021 Notes Claims" and together with the 2020 Notes Claims, the "Unsecured Notes Claims"), and the Holders of other general unsecured claims received their pro rata share of 1.25% of reorganized equity in the form of common stock and warrants to acquire 2,213,789 shares of common stock (the "Unencumbered Assets Equity Distribution") at a strike price of $46.00 per common share with an expiration date 42 months after the Effective Date;

Existing Equity: All existing equity interests prior to the Effective Date were extinguished, and existing equity holders did not receive any consideration in respect of their equity interests;

New Equity: On the Effective Date, we issued 24,687,500 shares of common stock of the reorganized equity. On November 9, 2016, we issued an additional 294,967 shares of common stock of the reorganized equity pursuant to the Plan. We will issue 17,533 additional common shares, with respect to general unsecured claims, pursuant to the Plan in a future distribution. The total authorized reorganized capital stock consists of 250,000,000 shares of common stock and 50,000,000 shares of preferred stock;

Exit Facility: Our RBL, which was redetermined with a borrowing base of $170.0 million in April 2016, was superseded, pursuant to the Plan, by the Exit Facility. The Exit Facility has an initial borrowing base of $170.0 million with no borrowing base redeterminations to occur until April 2018 (provided certain conditions are met) and semiannual borrowing base redeterminations each year on April 1 and October 1 thereafter. Until April 2018, unless the borrowing base is redetermined earlier, the amount available to be drawn under the Exit Facility is reduced by

Table of Contents

$40.0 million, and thereafter, we must maintain liquidity (as defined in the Exit Facility) equal to at least 20.0% of the effective borrowing base. In connection therewith, on the Effective Date, we made an additional payment of $40.0 million to lenders under our Exit Facility; and

Long-Term Incentive Plan: A management equity incentive plan (the "2016 LTIP") was established under which 10.0% of the reorganized equity (on a fully-diluted/fully-distributed basis) was reserved for grants to be made from time to time to the directors, officers, and other members of our management.

As a result of our restructuring, we estimate cash paid for interest will decrease from approximately $173.7 million per year to approximately $7.0 million per year, a cash interest savings of approximately $166.7 million per year.

The following table provides adjustments that reflect the consummation of transactions contemplated by the Plan, as of the Effective Date (excluding the Exit Facility):

	As of October 21, 2016 Predecessor	Reorganization Adjustments	As of October 21, 2016 Successor
		(in thousands)	
Unsecured Notes:			
2020 Senior Notes	$ 293,625	$ (293,625)	$
2021 Senior Notes	347,652	(347,652)	
Total Unsecured Notes	$ 641,277	$ (641,277)	$
Secured Notes:			
Second Lien Term Loan	$ 625,000	$ (625,000)	$
Third Lien Term Loan	529,653	(529,653)	
Total Secured Notes	$ 1,154,653	$ (1,154,653)	$
Total Debt (excluding Exit Facility)	**$ 1,795,930**	**$ (1,795,930)**	**$**

Upon our emergence on the Effective Date, we adopted fresh start accounting as required by United States generally accepted accounting principles ("US GAAP"). We qualified for fresh start accounting because (i) the holders of existing voting shares of the pre-emergence debtor-in-possession received less than 50% of the voting shares of the post-emergence successor entity and (ii) the reorganization value of our assets immediately prior to confirmation was less than the post-petition liabilities and allowed claims. We applied fresh start accounting as of October 21, 2016. Adopting fresh start accounting results in a new reporting entity for financial reporting purposes with no beginning retained earnings or deficit. The cancellation of all existing shares outstanding on the Effective Date and issuance of new shares in the reorganized Company caused a related change of control under US GAAP. As a result of the application of fresh start accounting, as well as the effects of the implementation of the Plan, our consolidated financial statements on or after October 21, 2016, are not comparable with our consolidated financial statements prior to that date. References to "Successor Period" relate to the financial position and results of operations for the period October 21, 2016 through December 31, 2016 and references to "Predecessor Period" refer to the financial position and results of operations of the Company from January 1, 2016 through October 20, 2016.

Business Strategy

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

Operate in a safe and environmentally responsible manner;

Table of Contents

Capitalize on our extensive technical and operating experience in our core areas of operation to strategically grow our production, increase our acreage position and enhance returns;

Build contiguous acreage positions that drive operating and infrastructure efficiencies;

Be the operator of our assets, whenever possible; and

Be the low cost driller and producer in the areas where we operate.

As a result of our recent restructuring, our significantly deleveraged balance sheet and improved liquidity position provides us with additional resources to develop our multi-year drilling inventory and expand our core acreage positions. Our focus will continue to be on controlling development and production costs and general and administrative expenses. For 2017, we intend to opportunistically increase our development activity while maintaining capital discipline and protecting our operating cash flows, including through the use of derivatives to protect our commodity price realizations.

With respect to the Mississippian Lime, we believe our team's early experience operating in this trend gives us a competitive advantage with respect to geological understanding, drilling and completion techniques and infrastructure development. We plan to leverage our advantages to cost effectively develop our Mississippian position and further expand our acreage through direct leasing, farm in arrangements and acreage swaps. During 2016, we earned approximately 24,248 net (45,440 gross) prospective acres through various farm-in agreements and plan to continue to utilize such agreements in the future. With respect to the Anadarko Basin, we believe our substantial acreage position largely held by production, the stacked pay characteristics of the trend and its long production history provide significant optionality with continued improvement in commodity prices and geologic understanding.

For 2017, we plan to allocate substantially all of our drilling and completions capital budget to development activities in the Mississippian Lime area based on the stronger economic returns expected from these assets in the current commodity price environment.

Summary of Oil and Gas Properties and Operations

Mississippian Lime

Our Mississippian Lime assets are located in Oklahoma and target the Mississippian Lime and Hunton formations. At December 31, 2016, our acreage consisted of approximately 103,093 net (142,773 gross) 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 12,894 net (19,888 gross) acres in Lincoln County, Oklahoma, which produces from, and is prospective in, the Hunton formation.

Our properties in this area represented 96% of our total proved reserves as of December 31, 2016. As of December 31, 2016, we held an average working interest and average net revenue interest of 82% and 66%, respectively, in this area.

For the Successor Period and Predecessor Period, our average daily production from our Mississippian Lime assets was as follows:

	Successor	**Predecessor**
	Period October 21, 2016 through December 31, 2016	**Period January 1, 2016 through October 20, 2016**
Oil (Bbls)	6,048	8,156
Natural gas liquids (Bbls)	4,843	5,326
Natural gas (Mcf)	58,816	68,107
Net Boe/day	**20,694**	**24,833**

Table of Contents

At December 31, 2016, we had one operated drilling rig in operation in the Mississippian Lime. For 2017, subject to the terms of our Exit Facility, we anticipate investing between $90.0 million and $100.0 million in the area while drilling between 24 and 26 gross operated wells.

Anadarko Basin

Our Anadarko Basin assets are located in Western Oklahoma and the Texas panhandle and target, or are prospective in, the Cleveland, Marmaton, Cottage Grove, Osage, Meramac and Tonkawa formations. At December 31, 2016, our acreage consisted of approximately 80,298 net (96,753 gross) acres in Texas and 24,627 net (43,671 gross) acres in western Oklahoma.

Our properties in this area represented 4% of our total proved reserves as of December 31, 2016. As of December 31, 2016, we held an average working interest and average net revenue interest of 64% and 51%, respectively, in this area.

For the Successor Period and Predecessor Period, our average daily production from the Anadarko Basin area was as follows:

	Successor	Predecessor
	Period October 21, 2016 through December 31, 2016	**Period January 1, 2016 through October 20, 2016**
Oil (Bbls)	1,508	1,927
Natural gas liquids (Bbls)	1,118	1,247
Natural gas (Mcf)	9,903	10,856
Net Boe/day	**4,277**	**4,983**

As of December 31, 2016, we did not operate any drilling rigs in this area and we do not expect to operate any drilling rigs in 2017. As a result, leasehold rights on acreage not held by production may expire during 2017, which could reduce our future drilling opportunities in this area. During 2016, we entered into a farm out agreement covering our acreage in Dewey County, Oklahoma which may be prospective for the NW Stack extension. To the extent commercially feasible, we will continue to pursue farm out arrangements with other operators to cost effectively preserve a portion of our leasehold rights with optionality to participate in any future development. During 2017, we will continue our efforts to reduce well maintenance and operating costs and production downtime. These efforts alone have not been and will not be sufficient to arrest the natural decline in production that occurs as we deplete our developed reserves.

Other

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 in the Gulf Coast (or Louisiana) as of December 31, 2016 or 2015.

Table of Contents

Reserves Information

Estimated Proved Reserves

The following table sets forth our estimated net proved reserves by product and type as of December 31, 2016 using SEC pricing:

	Oil (MBls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)	PV-10(1) (in millions)
Mississippian Lime:					
Proved developed producing	15,358	162,997	12,673	55,197	$ 306,623
Proved developed non-producing	1,540	20,335	1,597	6,526	20,553
Proved undeveloped	41,692	270,905	20,523	107,366	216,493
Total	58,590	454,237	34,793	169,089	$ 543,669
Anadarko Basin:					
Proved developed producing	2,800	18,122	2,079	7,899	$ 34,486
Proved developed non-producing					
Proved undeveloped					
Total	2,800	18,122	2,079	7,899	$ 34,486
Total Proved	**61,390**	**472,359**	**36,872**	**176,988**	**$ 578,155**

(1) We refer to PV-10 as the present value of estimated future net cash flows of estimated proved reserves as calculated in the respective reserves report using a discount rate of 10%. This amount includes projected revenues, estimated production costs, estimated future development costs and estimated cash flows related to future asset retirement obligations ("ARO"). PV-10 is a financial measure not defined under US GAAP. Accordingly, the following table reconciles total PV-10 to the standardized measure of discounted future net cash flows, which is the most directly comparable US GAAP financial measure. We believe the presentation of PV-10 provides useful information because it is widely used by investors in evaluating oil and natural gas companies without regard to specific income tax characteristics of such entities. PV-10 is not a measure of financial or operating performance under US GAAP, nor is it intended to represent the current market value of our estimated proved reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under US GAAP.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted cash flows (in thousands):

	As of December 31, 2016
PV-10	$ 578,155
Present value of future income tax, discounted at 10%	(48,205)
Standardized measure of discounted future net cash flows	**$ 529,950**

12

Table of Contents

Proved Undeveloped Reserves

The following table summarizes the changes in our estimated proved undeveloped reserves during the Successor Period and Predecessor Period (in MBoe):

Proved undeveloped reserves, December 31, 2015	**4,430**
Purchases of reserves in place	
Sales of reserves	
Extensions and discoveries	
Revisions of previous estimates	
Conversion to proved developed reserves	(4,430)
Proved undeveloped reserves, October 20, 2016	
Purchases of reserves in place	
Sales of reserves	
Extensions and discoveries	62,997
Revisions of previous estimates	48,019
Conversion to proved developed reserves	(3,650)
Proved undeveloped reserves, December 31, 2016	**107,366**

Due to uncertainty during the Predecessor Period regarding our ability to finance the development of our proved undeveloped reserves over a five year period, our proved undeveloped reserves were limited to only those locations that were undergoing drilling activity. Upon our emergence on the Effective Date, we undertook a process to review our five year development schedule in light of improved commodity pricing and the significant improvement in the Company's liquidity and outstanding long-term debt. In developing the Company's updated five year development schedule, the Company considered the forward pricing curve, the returns expected of our drilling program and cash available during this time period, which would include cash on hand, cash generated by operations and cash from borrowings. Based upon these factors, the Company developed an updated five year development plan and booked proved undeveloped reserves based upon this expected development plan. Proved undeveloped reserves that were removed from the proved category in prior years but subsequently reinstated after this review were classified as a revision in the above table. Proved undeveloped reserves that were not included in any proved category in prior years but included in our updated five-year development schedule were classified as an extension in the above tables. At December 31, 2016, 21,103 net MBoe of proved undeveloped reserves, comprising $34.1 million of PV-10 value were excluded from our five year development plan.

Independent Petroleum Engineers

For our Mississippian Lime and Anadarko Basin assets, our estimated reserves and related future net revenues at December 31, 2016, 2015 and 2014 are based on reports prepared by our independent third-party reserves engineering firm Cawley, Gillespie & Associates, Inc. ("CGA"), in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines in effect during such period as established by the SEC.

The reserve 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 29 years of practical experience in petroleum engineering, with over

27 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 our Gulf Coast (or Louisiana) assets at December 31, 2014 were based on reports prepared by an independent third-party reserves engineering firm, 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 reserve estimates shown herein for the periods indicated above were 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, CGA and NSAI 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.

Table of Contents

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 CGA and NSAI in their reserves estimation process. The primary inputs to the reserves 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 our 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 reserves database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are incorporated into the reserves 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 reserve estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, the reserves report is reviewed by our senior management with representatives of our independent reserve engineers and internal technical staff.

At December 31, 2016, Jeromy Garcia, our General Manager Mississippian Lime and Anadarko Basin Assets and Reserves, was primarily responsible for overseeing the preparation of our reserve estimates and reported directly to our Chief Executive Officer. Mr. Garcia has more than 16 years of experience in the oil and gas industry. Mr. Garcia spent the first portion of his career working for El Paso Production Company primarily working assets in the Gulf of Mexico. While at El Paso, Mr. Garcia served in multiple roles including reservoir and operational engineering. Mr. Garcia has also worked for small independents such as Whittier Energy and J&S Oil & Gas where he served as a reservoir engineer and Manager of Engineering. Mr. Garcia graduated from the University of Oklahoma in 2000 with a B.S degree in Petroleum Engineering and obtained his MBA from the University of Houston in 2009.

Production, Revenues and Price History

Oil, natural gas liquids ("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. While oil, natural gas and NGL prices increased throughout 2016, they remain substantially below the price levels realized during the majority of 2014. A decline in oil or natural gas prices from their current levels could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets. For additional information on these and other risks, see information set forth in "Risk Factors".

The following table sets forth information regarding our oil, NGLs and natural gas production, revenues and realized prices and production costs for the Successor Period, the Predecessor Period and

Table of Contents

the years ended December 31, 2015 and 2014. For additional details, see information set forth in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Successor		Predecessor					
	Period October 21, 2016 through December 31, 2016		Period January 1, 2016 through October 20, 2016		Year Ended December 31, 2015		Year Ended December 31, 2014	
Operating Data:								
Net production volumes:								
Oil (MBbls)		544		2,964		4,794		5,144
NGLs (MBbls)		429		1,932		2,473		2,417
Natural gas (MMcf)		4,948		23,215		28,403		25,013
Total oil equivalents (MBoe)		1,798		8,765		12,001		11,730
Average daily production (Boe/d)		24,971		29,816		32,880		32,137
Average Sales Prices:								
Oil, without realized derivatives (per Bbl)	$	46.96	$	37.99	$	45.40	$	90.71
Oil, with realized derivatives (per Bbl)	$	46.96	$	37.99	$	74.74	$	87.40
Natural gas liquids, without realized derivatives (per Bbl)	$	19.55	$	14.22	$	15.46	$	36.31
Natural gas liquids, with realized derivatives (per Bbl)	$	19.55	$	14.22	$	15.46	$	36.40
Natural gas, without realized derivatives (per Mcf)	$	2.76	$	2.08	$	2.35	$	3.97
Natural gas, with realized derivatives (per Mcf)	$	2.76	$	2.08	$	3.30	$	3.91
Costs and Expenses (per Boe of production):								
Lease operating and workover	$	8.52	$	6.02	$	6.79	$	6.79
Gathering and transportation	$	1.78	$	1.64	$	1.30	$	1.14
Severance and other taxes	$	0.72	$	0.59	$	0.72	$	2.07
Asset retirement accretion	$	0.12	$	0.16	$	0.13	$	0.15
Depreciation, depletion and amortization	$	7.22	$	7.11	$	16.55	$	23.01
Impairment of oil and gas properties	$		$	26.48	$	135.47	$	7.37
General and administrative	$	2.71	$	2.55	$	3.22	$	4.15
Acquisition and transaction costs	$		$		$	0.03	$	0.35
Debt restructuring costs and advisory fees	$		$	0.87	$	3.01	$	
Other	$		$		$	0.18	$	0.44

Table of Contents

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 for the Successor Period, Predecessor Period and the years ended December 31, 2015 and 2014:

	Successor	Predecessor		
	Period October 21, 2016 through December 31, 2016	Period January 1, 2016 through October 20, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Mississippian(1)				
Daily production volumes:				
Oil (Bbls)	6,035	8,147	10,187	8,401
NGLs (Bbls)	4,464	4,968	4,900	4,093
Natural gas (Mcf)	56,740	65,737	62,514	50,164
Total oil equivalents (Net Boe/day)	**19,956**	**24,071**	**25,506**	**20,855**
Anadarko				
Daily production volumes:				
Oil (Bbls)	1,508	1,927	2,680	4,014
NGLs (Bbls)	1,118	1,247	1,388	1,766
Natural gas (Mcf)	9,903	10,856	12,921	14,930
Total oil equivalents (Net Boe/day)	**4,277**	**4,983**	**6,222**	**8,268**

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

Productive Wells

The following table presents our total gross and net productive wells as of December 31, 2016:

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Total productive wells	753	527	93	67	846	594

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, 2016 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	80,048	58,070	82,613	57,917	162,661	115,987
Anadarko Basin	57,440	36,926	82,984	67,999	140,424	104,925
Gulf Coast			4,920	4,431	4,920	4,431
Total	**137,488**	**94,996**	**170,517**	**130,347**	**308,005**	**225,343**

Table of Contents

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2016 that will expire over the next three years by operating area unless operations are commenced upon or production is established upon the acreage (or upon lands spaced or pooled therewith) or we make additional lease rental payments prior to the expiration dates:

	Expiring 2017		Expiring 2018		Expiring 2019	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Mississippian Lime	27,248	14,540	7,119	3,799	1,439	768
Anadarko Basin	18,500	10,124	1,480	899	402	72
Gulf Coast	4,860	4,406	60	25		
Total Undeveloped Acreage Expirations	**50,608**	**29,070**	**8,659**	**4,723**	**1,841**	**840**

Approximately 15.6% of our net acreage, including acreage under option, was acquired in 2016, 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 reduced activity levels in the Anadarko Basin and divestitures in Louisiana, we may allow leasehold rights on acreage not held by production to expire in these areas, which could reduce our future drilling opportunities. Additionally, to the extent we cannot commence drilling operations upon or establish production from certain leases in the Mississippian Lime asset, certain of the leases within that asset area will expire, unless extended or renewed.

Drilling Activity

The following table summarizes our drilling activity for the Successor Period, the Predecessor Period and the years ended December 31, 2015 and 2014. 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:

	Successor		Predecessor					
	Period October 21, 2016 through December 31, 2016		Period January 1, 2016 through October 20, 2016		Year Ended December 31, 2015		Year Ended December 31, 2014	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development wells:								
Productive	3	3	40	38	84	74	119	97
Dry holes								
Total	**3**	**3**	**40**	**38**	**84**	**74**	**119**	**97**
Exploratory wells:								
Productive							1	1
Dry holes					3			
Total					3		**1**	**1**
Total wells	**3**	**3**	**40**	**38**	**87**	**74**	**120**	**98**

As of December 31, 2016, there were four gross (and four net) development wells awaiting completion; one development well was being drilled and no exploratory wells were being drilled.

Table of Contents

As of December 31, 2016, we had one drilling rig in operation. Our recent drilling activity has primarily focused on development, delineation and appraisal of our primary operating areas in our Mississippian Lime asset.

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 Lime asset, where the majority of our natural gas production is dedicated to one purchaser for the economic life of the relevant assets. For the Successor Period, two purchasers accounted for 40% and 29%, respectively, of the Company's revenue. For the Predecessor Period, two purchasers accounted for 46% and 29%, respectively, of the Company's revenue. 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. 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 such production.

We are party to a gas purchase, gathering and processing contract in our Mississippian Lime asset, which includes certain minimum 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 have historically, and continue to currently, deliver 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 preliminary 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. Our oil and natural gas properties are generally subject to customary royalty interests or other burdens, and a majority of our properties are subject to liens to secure borrowings under our Exit Facility as well as liens for current taxes and other burdens, none of which we believe materially interfere with our ability to operate or develop such properties.

Seasonality

Weather conditions often affect the demand for, and the associated prices of, crude oil, natural gas and NGLs. Further, weather conditions could delay our drilling and production activities, which impacts our ability to achieve our overall business objectives. 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.

Table of Contents

Competition

The oil and natural gas industry is a highly competitive environment for acquiring properties, attracting and retaining trained personnel and obtaining the equipment necessary to develop and produce reserves. 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 this 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 any given 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/or individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on our 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 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.

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 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.

Table of Contents

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").

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.

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.

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.

Table of Contents

Any changes in federal or state environmental laws and regulations or re-interpretation of applicable enforcement policies that result in more stringent or 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 listed 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. 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.

Certain of our operations or activities may also be 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 third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. 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, 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. In addition, in May 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. In May 2016, the EPA also issued final rules that require the reduction of volatile organic compound and methane emissions from additional new, modified or reconstructed oil and gas emissions sources. Since the methane and aggregation rules were published in the Federal Register after May 31, 2016, they are potentially subject to repeal by the new Congress. These new regulations could, among other things, require installation of new emission controls on some of the drilling program's equipment and production facilities, 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. Most recently, in May 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector. In November 2016, the Bureau of Land Management ("BLM") issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands. The May 2016 and November 2016 methane rules are potentially subject to repeal by the new Congress. We cannot predict which areas, if any, the EPA may choose to regulate with respect to GHG emissions next.

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. On an international level, the United States is one of almost 200 nations that is party to the Paris Agreement adopted in December 2015 to reduce global GHG emissions. It is not possible at this time to predict if or when the United States might impose restrictions on GHG emissions as a result of this agreement. 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. 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 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 may restrict the types and quantities of fluids that may be disposed. While we believe that our disposal well operations substantially comply with requirements under the applicable UIC programs, 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 or reduce the amount of oil and/or natural gas that we can produce from our wells.

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 "the 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, the Oklahoma Corporation Commission ("OCC") has 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 Oil and Gas Conservation Division ("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 Arbuckle 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. In addition, 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 were required to reduce disposal volume. The plan affected 7 disposal wells we currently operate that dispose in the Arbuckle formation. On February 16, 2016, the OGCD requested we curtail our wastewater disposal volumes at 11 wells by approximately 40%. On March 7, 2016 and August 19, 2016, the OGCD identified additional wells that were required to reduce disposal volume, including nine that we operate. The OGCD established caps for additional wells, including 16 that we operate, on February 24, 2017. While our current plans are for future disposal wells to inject into formations other than the Arbuckle and we currently operate 8 such non-Arbuckle formation disposal wells, we continue to utilize wells that dispose into the Arbuckle formation. We have timely met and satisfied all requests

Table of Contents

of the OCC regarding changes and/or reductions in disposal capacity in our operated disposal wells, all while maintaining our production base without any negative material impact thereto. We believe we are currently in compliance with the OGCD's latest requests regarding Arbuckle injection limits; however a change in disposal well regulations or injection limits, 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 and/or reduce the volume of oil and natural gas that we produce from our wells.

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.

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/or 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 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 published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; issued in June 2016 final effluent limit guidelines that saltwater from shale resource extraction operations must meet before discharging to publicly owned wastewater treatment plants; 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 air emissions standards issued in May 2016 and the effluent limit guidelines issued in June 2016 are potentially subject to repeal by the new Congress. Also, the BLM published a final rule containing disclosure requirements and other mandates for hydraulic fracturing on federal and Indian lands in March of 2015. However, the U.S. District Court of Wyoming struck down this rule in June 2016; the ruling is currently on appeal before the U.S. Tenth Circuit Court of Appeals.

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. Some states have elected to prohibit hydraulic fracturing altogether, but not the states in which we own and operate oil and gas wells. 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.

Table of Contents

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 February 2016 finalized a rule altering how it identifies critical habitat for endangered and threatened species. 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 by 2017. 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.

Occupational Safety and Health Act, as amended ("OSHA")

We are subject to the requirements of 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.

Table of Contents

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

The recent declines in oil and, to a lesser extent, NGL and natural gas prices have adversely affected our business, financial condition and results of operations and our ability to meet our future 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. During the period from January 1, 2014 through January 31, 2017, the WTI spot price for oil declined from a high of $107.95 per Bbl on June 20, 2014 to $26.19 per Bbl on February 11, 2016, and the Henry Hub spot price for natural gas has declined from a high of $8.15 per MMBtu on February 10, 2014 to a low of $1.49 per MMBtu on March 4, 2016. 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 production and a portion of our natural 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 throughout 2016 adversely affected our cash flows, borrowing ability and the present value of our reserves. Lower oil,

Table of Contents

NGL and natural gas prices may also reduce the amount of oil, NGLs and natural gas that we can produce economically. Any sustained periods of low prices for 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 significant downward adjustments to our estimated proved reserves. As a result, a 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 recently emerged from bankruptcy, which could adversely affect our business and relationships.

It is possible that our having filed for bankruptcy protection and our recent emergence from the Chapter 11 Cases could adversely affect our business and relationships with our customers, vendors, royalty or working interest owners, contractors, employees or suppliers. Due to these uncertainties, many risks exist, including the following:

- key suppliers or vendors could terminate their relationship with us or require additional financial assurances or enhanced performance from us;
- the ability to renew existing contracts may be adversely affected;
- the ability to attract, motivate and/or retain key executives and employees may be adversely affected;
- employees may be distracted from performance of their duties or more easily attracted to other employment opportunities; and
- landowners may not be willing to lease acreage to us.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial condition and reputation. We cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations in the future.

Our Exit Facility contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

The Exit Facility limits our ability, among other things, to:

- incur additional indebtedness;
- incur liens;
- enter into sale and lease back transactions;
- make certain investments;
- make certain capital expenditures;
- consolidate, merge, sell, or otherwise dispose of all or substantially all of our assets;

pay dividends or make other distributions or repurchase or redeem our stock;

enter into transactions with our affiliates;

engage or enter into any new lines of business;

enter into certain marketing activities for hydrocarbons;

create additional subsidiaries;

prepay, redeem, or repurchase certain of our indebtedness; and

Table of Contents

amend or modify certain provisions of our (and Midstates Sub's) organizational documents.

The Exit Facility also requires us to comply with certain financial maintenance covenants as discussed above. A breach of any of these covenants could result in a default under our Exit Facility. If a default occurs, the lenders under the Exit Facility may elect to declare all borrowings thereunder outstanding, together with accrued interest and other fees, to be immediately due and payable. The lenders under the Exit Facility would also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If we are unable to repay our indebtedness when due or declared due, the lenders thereunder will also have the right to proceed against the collateral pledged to them to secure the indebtedness. If such indebtedness were to be accelerated, our assets may not be sufficient to repay in full our secured indebtedness.

Upon our emergence from the Chapter 11 Cases, the composition of our board of directors changed significantly.

Pursuant to the Plan, the composition of the board of directors changed significantly. The new directors have different backgrounds, experiences and perspectives from those individuals who previously served on the Board and, thus, may have different views on the issues that will determine our future. There is no guarantee that the new board of directors will pursue, or will pursue in the same manner, our current strategic plans. As a result, the future strategy and our plans may differ materially from those of the past.

The ability to attract and retain key personnel is critical to the success of our business and may be affected by our emergence from the Chapter 11 Cases.

The success of our business depends on key personnel. The ability to attract and retain these key personnel may be difficult in light of our emergence from the Chapter 11 Cases, the uncertainties currently facing the business and changes we may make to the organizational structure to adjust to changing circumstances. We may need to enter into retention or other arrangements that could be costly to maintain. If executives, managers or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them in a timely manner and we could experience significant declines in productivity.

We may be unable to obtain funding in the capital markets on terms we find acceptable, or our borrowings base may be subject to downward redeterminations in the future.

Historically, we have used our cash flows from operations and borrowings under our RBL 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. On the Effective Date, the existing RBL was superseded, and we entered into the Exit Facility with the lenders under the existing RBL. The Exit Facility has an initial borrowing base of $170.0 million with no borrowing base redeterminations to occur until April 2018 (provided certain conditions are met) and semiannual borrowing base redeterminations thereafter. 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 Exit Facility, which could result in an event of default.

In the future, we may not be able to access adequate funding under our Exit 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 Exit 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.

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

At December 31, 2016, we had $130.0 million outstanding under our Exit Facility, including $1.9 million in letters of credit. We may incur a significant amount of additional indebtedness in the future. Should our current level of indebtedness increase significantly, it 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 redetermination could require us to repay a portion of our then outstanding bank borrowings; and
- impairing our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness would increase 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.

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 Exit Facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios, including an EBITDA to interest expense coverage ratio limitation of 3.00:1.00, a ratio limitation of Total Net Indebtedness (as defined in the Exit Facility) to EBITDA of not more than 2.25:1.00 through April 1, 2018 and not more than 3.00:1.00 thereafter, and a capital expenditure limitation of $50.0 million for the 6 months ended December 31, 2016, $81.0 million for the year ended December 31, 2017, $85.0 million for the year ended December 31, 2018 and $78.0 million for the year ended December 31, 2019. Additionally, after April 2018 (unless the borrowing base is redetermined earlier), we must maintain liquidity (cash plus available commitments) equal to at least 20.0% of the effective borrowing base.

Table of Contents

As of December 31, 2016, 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 Exit Facility that is not waived by our lenders or otherwise cured could lead to a termination of our Exit Facility, acceleration of all amounts due under our Exit 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.

Our historical financial information may not be indicative of our future financial performance.

On the effective date of our emergence from the Chapter 11 Cases on October 21, 2016, we adopted fresh start accounting, as a consequence of which our assets and liabilities were adjusted to fair values and our accumulated deficit was restated to zero. Accordingly, our financial condition and results of operations following our emergence from the Chapter 11 Cases may not be comparable to the financial condition and results of operations reflected in our historical financial statements. Further, as a result of the implementation of the Plan and the transactions contemplated thereby, our historical financial information may not be indicative of our future financial performance.

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;

Table of Contents

- 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.

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, 2016, 2015 and 2014, 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 market value of our reserves.

Due to the recent decrease in oil and natural gas prices and if prices decrease in the future, we may 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. The risk that we will be required to recognize impairments of our oil and natural gas properties increases during

Table of Contents

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 future declines in commodity prices.

Oil, NGL and natural gas prices are volatile and a portion of our production is not subject to hedging. As a result, a portion of 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. At December 31, 2016, we had no outstanding commodity derivative contracts, although we entered into various derivatives subsequent to December 31, 2016 for a portion of our expected 2017 and first quarter 2018 production. As such, a portion of our 2017 and 2018 production will be sold at market prices, leaving us 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 will continually reevaluate and consider whether in the long-term we will hedge any of our future production.

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

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil, NGL and natural gas, 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.

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

We incurred a net loss of $1.8 billion for the year ended December 31, 2015. Our development of, and participation in, an increasing 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.

Table of Contents

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.

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.

Our producing properties are located in the Mississippian Lime and in the Anadarko Basin, making us vulnerable to risks associated with operating in a limited number of geographic areas.

All of our producing properties are geographically concentrated in the Mississippian Lime and Anadarko Basin, and at December 31, 2016, all of our total estimated proved reserves were attributable to properties located in these areas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, NGLs or natural gas.

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 or have reasonable access to 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 could 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 and the value of our undeveloped acreage in this area could decline.

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 disposal wells.

In addition, concerns have been raised about the potential for earthquakes to occur from the use of underground injection disposal 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/or injecting into certain formations, thereby increasing the cost of disposal in our operations. We operate our own injection wells in addition to using 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.

Table of Contents

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of saltwater produced in conjunction with 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 in conjunction with the oil and natural gas produced from 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 may be subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements.

As stated above under "Water Discharges and Fluid Injection", 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 requiring us to shut down disposal wells, could require the Company to cease operations at a substantial number of its oil and natural gas wells, which would 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.

Table of Contents

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 natural gas production.

The marketing of oil and natural 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 natural gas production. Our plans to develop and sell our oil and natural 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.

Table of Contents

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. 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. 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.

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 the Texas panhandle and western 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.

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.

Table of Contents

Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production. Additionally, future federal or state legislation may impose new or increased taxes or fees on oil and natural gas extraction, transportation and sales.

Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal and state income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations. Additionally, legislation could be enacted that increases the taxes states impose on oil and natural gas extraction. Moreover, former President Obama proposed, as part of the Budget of the United States Government for Fiscal Year 2017, to impose an "oil fee" of $10.25 on a per barrel equivalent of crude oil. This fee would be collected on domestically produced and imported petroleum products. The fee would be phased in evenly over five years. The adoption of this, or similar proposals, could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil.

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 natural gas may expose us to extensive regulation.

The FERC, the CFTC and the FTC 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.

Table of Contents

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 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, 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. In addition, in May 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. In May 2016, the EPA also issued final rules that require the reduction of volatile organic compound and methane emissions from additional new, modified or reconstructed oil and gas emissions sources. Since the methane and aggregation rules were published in the Federal Register after May 31, 2016, they are potentially subject to repeal by the new Congress. 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.

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 adopted regulations under existing provisions of the CAA to address GHG emissions. For example, the EPA has adopted regulations that 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. Most recently, in May 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector. In November 2016, the Bureau of Land Management ("BLM") issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands. The May 2016 and November 2016 methane rules are potentially subject to repeal by the new Congress.

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. On an international level, the United States is one of almost 200 nations that is party to the Paris Agreement adopted in December 2015 to reduce global GHG emissions. It is not possible at this time to predict if or when the United States might impose restrictions on GHG emissions as a result of this agreement. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs and 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.

Table of Contents

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 published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations; issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; issued in June 2016 final effluent limit guidelines that saltwater from shale resource extraction operations must meet before discharging to publicly owned wastewater treatment plants; 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 air emissions standards issued in May 2016 and the effluent limit guidelines issued in June 2016 are potentially subject to repeal by the new Congress. Also, the BLM published a final rule containing disclosure requirements and other mandates for hydraulic fracturing on federal and Indian lands in March of 2015. However, the U.S. District Court of Wyoming struck down this rule in June 2016; the ruling is currently on appeal before the U.S. Tenth Circuit Court of Appeals. 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, or that prohibit hydraulic fracturing altogether. 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 Safe Drinking Water Act ("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

Table of Contents

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.

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

In one of its rulemaking proceedings still pending under the DF Act, the CFTC issued on December 5, 2016, re-proposed rules imposing position limits for certain futures and option contracts in various commodities (including oil and gas) and for swaps that are their economic equivalents. Under the proposed rules on position limits, certain types of hedging transactions are exempt from these limits on the size of positions that may be held, provided that such hedging transactions satisfy the CFTC's requirements for certain enumerated "bona fide hedging" transactions or positions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us in connection with covered derivatives activities to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although the Company expects to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge its commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that the Company uses for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margins. Posting of collateral could impact liquidity and reduce cash available to the Company for its needs. The DF Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The full impact of the DF Act and related regulatory requirements upon the Company's business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The DF Act and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, increase our exposure to less creditworthy counterparties or reduce liquidity. If we reduce our use of derivatives as a result of the DF Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

Finally, the DF Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the DF Act is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Table of Contents

Risks Relating to our Common Stock

The exercise of all or any number of outstanding warrants or the issuance of stock-based awards may dilute your holding of shares of our common stock.

Pursuant to the Plan, we issued 24,994,867 shares of common stock in the reorganized Company, 4,411,765 warrants with a strike price of $24.00 per common share of the reorganized equity and 2,213,789 warrants with a strike price of $46.00 per common share of the reorganized equity. Additionally, a total of 3,513,950 shares of common stock of the reorganized equity are reserved for issuance under the 2016 LTIP as equity-based awards to employees, directors and certain other persons. The exercise of equity awards, including any stock options that we may grant in the future, and warrants, and the sale of shares of our common stock underlying any such options or the warrants, could have an adverse effect on the market for our common stock, including the price that an investor could obtain for their shares. Investors may experience dilution in the net tangible book value of their investment upon the exercise of the warrants and any stock options that may be granted or issued pursuant to the 2016 LTIP in the future.

The price and trading volume of our common stock may fluctuate significantly.

The market price of our common stock may be highly volatile and could be subject to wide fluctuations. In addition, the trading volume of our common stock may fluctuate and cause significant price variations to occur. Volatility in the market price of our common stock may prevent you from being able to sell your shares at or above the price at which you were granted your shares of common stock or above the price you paid to acquire your shares of common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our new capital structure as a result of the transactions contemplated by the Plan;
- our limited trading history subsequent to our emergence from the Chapter 11 Cases;
- our limited trading volume;
- the concentration of holdings of our common stock;
- the lack of comparable historical financial information due to our adoption of fresh start accounting;
- actual or anticipated variations in our operating results and cash flow;
- the nature and content of our earnings releases, announcements or events that impact our products, customers, competitors or markets; and
- business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions.

Future sales of our common stock in the public market or the issuance of securities senior to our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and our ability to raise funds in stock offerings.

A large percentage of our shares of common stock are held by a relatively small number of investors. Further, we entered into a registration rights agreement with certain of those investors pursuant to which we filed a registration statement with the SEC to facilitate potential future sales of such shares by them. Sales by us or our stockholders of a substantial number of shares of our common stock in the public markets, or even the perception that these sales might occur (such as upon the filing of the aforementioned registration statement), could cause the market price of our common stock to decline or could impair our ability to raise capital through a future sale of, or pay for acquisitions using, our equity securities.

46

Table of Contents

We are currently authorized to issue 250,000,000 shares of common stock and 50,000,000 shares of preferred stock. As of December 31, 2016, we had outstanding approximately 24,994,867 shares of common stock and warrants and options to purchase an aggregate of 6,625,554 shares of our common stock. We have also reserved an additional 3,513,950 shares for issuance under the 2016 LTIP. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock.

We may issue common stock or other equity securities senior to our common stock in the future for a number of reasons, including to finance acquisitions, to adjust our leverage ratio, and to satisfy our obligations upon the exercise of warrants and options, or for other reasons. We cannot predict the effect, if any, that future sales or issuances of shares of our common stock or other equity securities, or the availability of shares of common stock or such other equity securities for future sale or issuance, will have on the trading price of our common stock.

There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.

As of December 31, 2016, funds advised by Avenue Capital Group, Centerbridge Partners and Fir Tree Partners held approximately 13.98%, 18.33% and 25.58%, respectively, of our post-reorganization common stock. Circumstances may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures or other transactions, including the issuance of additional shares or debt, that, in their judgment, could enhance their investment in us or another company in which they invest. Such transactions might adversely affect us or other holders of our common stock. In addition, our significant concentration of share ownership may adversely affect the trading price of our common shares because investors may perceive disadvantages in owning shares in companies with significant stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of December 31, 2016, 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 16. 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

In connection with our reorganization and emergence from bankruptcy, all equity interests outstanding prior to emergence October 21, 2016 were cancelled. On the Effective Date, we issued 24,687,500 shares of common stock of the reorganized Company. On November 8, 2016, the Company issued 12,400 shares of common stock to employees and non-employee directors, which vested immediately upon issuance. On November 9, 2016, we issued an additional 294,967 shares of common stock of the reorganized Company pursuant to the Plan. We will issue 17,533 additional common shares, with respect to general unsecured claims, pursuant to the Plan in a future distribution. The total authorized capital stock of the reorganized equity consists of 250,000,000 shares of common stock and 50,000,000 shares of preferred stock. The 2016 LTIP was established under which 10.0% of the equity in the reorganized equity (on a fully-diluted/fully-distributed basis) was reserved for grants to be made from time to time to the directors, officers, and other members of management of the reorganized Company. For further discussion of the Plan, please see " Note 2. Emergence from Voluntary Reorganization under Chapter 11 Proceedings" in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Prior to October 24, 2016, our common stock traded on the OTC Pink market under the symbol "MPOY" and, on October 24, 2016, our new common stock began trading on the NYSE MKT under the symbol "MPO". The high and low sales prices per share are as follows:

	Price Range	
2016	**High**	**Low**
Fourth Quarter (from October 24)	$ 25.00	$ 17.01

On March 27, 2017, the last sales price of our common stock, as reported on the NYSE MKT, was $18.50 per share.

As of March 27, 2017, there were 24,994,867 shares of common stock outstanding.

Holders

The number of shareholders of record of our common stock was one on March 27, 2017.

Dividends

We have not paid any cash dividends since inception. In addition, our Exit Facility limits and restricts 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.

Table of Contents

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 stockholders from the date our common stock began trading on the NYSE MKT (October 24, 2016) through December 31, 2016, as compared to the cumulative 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 opening price of $19.00 per share and invested in the S&P 500 and the S&P O&G E&P on October 24, 2016 at the closing price on such date; and

- Dividends, if any, are reinvested.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

The following tables set forth our selected financial data over the five-year period ended December 31, 2016. The information in the table below has been derived from our 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 our 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 indicated. The historical financial data for the Successor Period and Predecessor Period, as well as December 31, 2015 and 2014, are derived from our audited 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, 2013 and 2012 are derived from our audited financial statements not included in this Annual Report on Form 10-K. As discussed in " Note 3. Fresh Start Accounting" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K, upon our emergence on the Effective Date, we adopted fresh start accounting as required by US GAAP. We applied fresh start accounting as of October 21, 2016. As a result of the application of fresh start accounting, as well as the effects of the implementation of the Plan, our consolidated financial statements on or after the Effective Date are not comparable with our consolidated financial statements prior to that date.

	Successor	Predecessor				
(in thousands, except per share amounts)	**For the Period October 21, 2016 through December 31, 2016**	**For the Period January 1, 2016 through October 20, 2016**	**December 31, 2015(1)**	**2014(2)**	**2013(3)**	**2012(4)**
Income Statement Data						
Total revenues	$ 48,525	$ 193,228	$ 365,145	$ 794,183	$ 469,506	$ 247,673
Net income (loss)	9,930	1,323,079	(1,797,195)	116,929	(343,985)	(150,097)
Net income (loss) attributable to common shareholders(5)	9,650	1,306,557	(1,798,143)	67,271	(359,574)	(156,597)
Net income (loss) per share attributable to common shareholders(6)						
Basic and diluted	$ 0.39	$ 122.74	$ (232.74)	$ 10.13	$ (54.68)	$ (26.11)
Other Financial Data						
Net cash provided by operating activities	$ 23,644	$ 61,997	$ 213,383	$ 351,544	$ 237,588	$ 145,019
Net cash used in investing activities	(23,346)	(133,307)	(294,556)	(404,264)	(1,204,332)	(781,378)
Net cash provided by financing activities		66,757	150,709	31,114	981,029	647,893
Adjusted EBITDA(7)	26,766	93,465	315,340	474,098	330,759	144,619

(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 8. Acquisition 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 sale of all ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana ("Pine Prairie

Table of Contents

Disposition"), which closed on May 1, 2014. For a discussion of significant divestitures, see " Note 8. Acquisition 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.

(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 11. 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) 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.

Presented below is our historical financial data as of the dates indicated. The historical balance sheet data as of December 31, 2016 and December 31, 2015 are derived from our audited consolidated financial statements and the notes thereto included in Item 15 in this Annual Report on Form 10-K. The historical balance sheet data as of December 31, 2014, 2013 and 2012 are derived from our audited financial statements not included in this Annual Report on Form 10-K.

	Successor	Predecessor			
		December 31,			
(in thousands, except per share amounts)	**December 31, 2016**	**2015(1)**	**2014(2)**	**2013(3)**	**2012(4)**
Balance Sheet Data					
Cash and cash equivalents	$ 76,838	$ 81,093	$ 11,557	$ 33,163	$ 18,878
Net property and equipment	631,595	523,869	2,123,116	2,094,894	1,567,408
Total assets	760,939	679,167	2,447,175	2,308,637	1,665,927
Total debt, including debt classified as current(5)	128,059	1,890,944	1,706,532	1,667,680	675,917
Stockholders' equity (deficit)	561,814	(1,326,066)	465,862	339,999	677,469
Weighted average number of common shares outstanding	25,009	7,726	6,644	6,576	5,997

(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 8. Acquisition 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 8. Acquisition 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.

Table of Contents

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

(4) The year ended December 31, 2012 reflects the Eagle Property Acquisition, which closed on October 1, 2012.

(5) At December 31, 2015, we were in default under our RBL. As a result, our debt was classified as current as of December 31, 2015.

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, reorganization items 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 US 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 US 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.

Table of Contents

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

	Successor	Predecessor				
	For the Period October 21, 2016 Through December 31, 2016	For the Period January 1, 2016 Through October 20, 2016	December 31,			
			2015	2014	2013	2012
Adjusted EBITDA reconciliation to net income (loss):						
Net income (loss)	$ 9,930	$ 1,323,079	$ (1,797,195)	$ 116,929	$ (343,985)	$ (150,097)
Depreciation, depletion and amortization	12,974	62,302	198,643	269,935	250,396	125,561
Impairment in carrying value of oil and gas properties		232,108	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
Net cash received (paid) for commodity derivative contracts not designated as hedging instruments			167,669	(18,332)	(17,585)	(15,825)
Reorganization items, net		(1,594,281)				
Income tax expense (benefit)			(9,641)	6,395	(146,529)	157,886
Interest income		(81)	(115)	(39)	(33)	(245)
Interest expense net of amounts capitalized (Predecessor Period excludes interest expense of $89.5 million on senior and secured notes)	743	66,360	163,148	137,548	83,138	12,999
Asset retirement obligation accretion	210	1,414	1,610	1,706	1,435	723
Share-based compensation, net of amounts capitalized	2,909	2,564	4,408	8,618	5,713	2,459
Adjusted EBITDA	**$ 26,766**	**$ 93,465**	**$ 315,340**	**$ 474,098**	**$ 330,759**	**$ 144,619**

Table of Contents

	Successor For the Period October 21, 2016 Through December 31, 2016	Predecessor For the Period January 1, 2016 Through October 20, 2016	December 31, 2015	2014	2013	2012
Adjusted EBITDA reconciliation to net cash provided by operating activities:						
Net cash provided by operating activities	$ 23,644	$ 61,997	$ 213,383	$ 351,544	$ 237,588	$ 145,019
Changes in working capital(1)	2,442	(33,365)	(58,293)	(7,098)	16,021	(11,624)
Interest income		(81)	(115)	(39)	(33)	(245)
Interest expense, net of amounts capitalized and accrued but not paid (Predecessor Period excludes interest expense of $89.5 million on senior and secured notes)(2)	743	71,075	171,681	137,548	83,138	12,999
Operating lease abandonment(3)		(1,574)				
Amortization of deferred financing costs	(63)	(4,587)	(11,316)	(7,857)	(5,955)	(1,530)
Adjusted EBITDA	**$ 26,766**	**$ 93,465**	**$ 315,340**	**$ 474,098**	**$ 330,759**	**$ 144,619**
Acquisition and transaction costs			330	4,129	11,803	14,884
Debt restructuring costs and advisory fees		7,590	36,141			
Adjusted EBITDA before transaction and advisory costs	**$ 26,766**	**$ 101,055**	**$ 351,811**	**$ 478,227**	**$ 342,562**	**$ 159,503**

(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 Predecessor Period excludes $3.5 million in accrued paid-in-kind interest on the Third Lien Notes and $8.2 million in amortization of deferred gain on troubled debt restructuring. 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 10. Debt" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

(3) Operating lease abandonment for the Predecessor Period includes a $1.6 million decrease in the liability previously recorded for the abandonment of the Houston office lease.

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 in oil and liquids-rich basins in the onshore United States. Our operations are primarily focused on exploration and production activities in the Mississippian Lime and Anadarko Basin.

Our current activities are focused on the evaluation and development of our current acreage position to maximize the value of our primarily oil and liquids rich resource potential in our core areas of operations and identifying potential expansion opportunities in those areas, specifically the Mississippian Lime. During 2016, we earned approximately 24,248 net (45,440 gross) prospective acres through various farm-in agreements and plan to continue to utilize such agreements in the future. For 2017, we plan to allocate substantially all of our drilling and completions capital budget to development activities in the Mississippian Lime area based on the stronger economic returns expected from these assets in the current commodity price and cost environment.

As of December 31, 2016, our properties consisted of approximately 225,000 net acres of leasehold, with 846 gross productive wells, 68% of which we operate, and in which we held an average working interest of approximately 76%. As of December 31, 2016, our estimated net proved reserves were 176,988 MMBoe, of which 56% was oil or NGLs and 39% was proved developed. For the Successor Period and Predecessor Period, our properties had aggregate net daily production of approximately 24,971 Boe/d and 29,816 Boe/d, respectively.

On April 21, 2015, we closed on the sale of certain of our oil and gas properties in Beauregard and Calcasieu Parishes, Louisiana, for approximately $44.0 million, before customary post-closing adjustments. We have no proved reserves in the Gulf Coast (or state of Louisiana) as of December 31, 2016 or 2015.

As discussed in " Note 3. Fresh Start Accounting" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K, upon our emergence from the Chapter 11 cases on October 21, 2016, we adopted fresh start accounting as required by US GAAP. As a result of the application of fresh start accounting, as well as the effects of the implementation of the Plan, our consolidated financial statements on or after October 21, 2016, are not comparable with our consolidated financial statements prior to that date. References to "Successor Period" relate to the financial position and results of operations for the period October 21, 2016 through December 31, 2016 and references to "Predecessor Period" refer to the financial position and results of operations of the Company from January 1, 2016 through October 20, 2016.

Table of Contents

Recent Developments

Emergence from Chapter 11 Bankruptcy

On the Petition Date, we filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court. Our Chapter 11 cases were jointly administered under the case styled *In re Midstates Petroleum Company, Inc., et al., Case No. 16-32237*.

On September 28, 2016, the Bankruptcy Court entered the Confirmation Order, which approved and confirmed the Plan. On the Effective Date, we satisfied the conditions to effectiveness set forth in the Confirmation Order and in the Plan, and the Plan therefore became effective in accordance with its terms and we emerged from bankruptcy.

Plan of Reorganization

Pursuant to the confirmed Plan, the significant transactions that occurred upon the Effective Date were as follows:

- Substantial Deleveraging of the Balance Sheet: The permanent pay-down of $81.3 million of our RBL, with a $170.0 million Exit Facility established upon the Effective Date, (ii) the pay-down of $60.0 million of our Second Lien Notes in cash, and (iii) the conversion into equity of all of our remaining debt junior to the RBL;

- Credit Facility Claims: Holders of Credit Facility Claims received their pro rata share of approximately $81.3 million in cash and the RBL was superseded, pursuant to the Plan, by the Exit Facility, as further described below;

- Second Lien Notes Claims: Holders of Second Lien Notes Claims received their pro rata share of (i) 96.25% of the reorganized equity in the form of common stock and (ii) a cash payment of $60.0 million;

- Third Lien Notes Claims: Holders of Third Lien Notes Claims, pursuant to the Second/Third Lien Plan Settlement, received their pro rata share of 2.5% of the reorganized equity in the form of common stock and warrants to acquire 4,411,765 shares of common stock at a strike price of $24.00 per common share with an expiration date 42 months after the Effective Date;

- Unsecured Claims: Unsecured Notes Claims and the Holders of other general unsecured claims received their pro rata share of 1.25% of reorganized equity in the form of common stock and warrants to acquire 2,213,789 shares of common stock at a strike price of $46.00 per common share with an expiration date 42 months after the Effective Date;

- Existing Equity: All existing equity interests were extinguished and existing equity holders did not receive any consideration in respect of their equity interests;

- New Equity: On the Effective Date, we issued 24,687,500 shares of common stock of the reorganized equity. On November 9, 2016, we issued an additional 294,967 shares of common stock of the reorganized equity pursuant to the Plan. We will issue 17,533 additional common shares, with respect to general unsecured claims, pursuant to the Plan in a future distribution. The total authorized reorganized capital stock consists of 250,000,000 shares of common stock and 50,000,000 shares of preferred stock;

- Exit Facility: Our RBL, which was redetermined with a borrowing base of $170.0 million in April 2016, was superseded, pursuant to the Plan, by the Exit Facility. The Exit Facility has an initial borrowing base of $170.0 million with no borrowing base redeterminations to occur until April 2018 (provided certain conditions are met) and semiannual borrowing base redeterminations each year on April 1 and October 1 thereafter. Until April 2018, unless the borrowing base is redetermined earlier, the amount available to be drawn under the Exit Facility is reduced by

Table of Contents

$40.0 million, and thereafter, we must maintain liquidity (as defined therein) equal to at least 20.0% of the effective borrowing base. In connection therewith, on the Effective Date, we made an additional payment of $40.0 million to lenders under our Exit Facility; and

Long-Term Incentive Plan: The LTIP was established under which 10.0% of the reorganized equity (on a fully-diluted/fully-distributed basis) was reserved for grants to be made from time to time to directors, officers, and other members of management.

Fresh Start Accounting

Upon our emergence on the Effective Date, we adopted fresh start accounting as required by US GAAP. We qualified for fresh start accounting because (i) the holders of existing voting shares of the pre-emergence debtor-in-possession received less than 50% of the voting shares of the post-emergence successor entity and (ii) the reorganization value of our assets immediately prior to confirmation was less than the post-petition liabilities and allowed claims.

As discussed in " Note 3. Fresh Start Accounting" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K, we applied fresh start accounting as of October 21, 2016. Adopting fresh start accounting results in a new reporting entity for financial reporting purposes with no beginning retained earnings or deficit. The cancellation of all existing shares outstanding on the Effective Date and issuance of new shares in the reorganized Company caused a related change of control under US GAAP.

As a result of the application of fresh start accounting, as well as the effects of the implementation of the Plan, our consolidated financial statements on or after October 21, 2016, are not comparable with our consolidated financial statements prior to that date.

Stock Listing

Our common stock was listed on the NYSE on April 25, 2012 through February 3, 2016 under the symbol "MPO". On February 3, 2016, our stock was delisted by the NYSE and began trading on the OTC Pink market under the symbol "MPOY" through October 21, 2016. On October 21, 2016, in connection with our emergence from Chapter 11, our existing common shares traded under the symbol MPOY were cancelled. On October 24, 2016, our newly issued shares of common stock in the reorganized equity were listed and began trading on the NYSE MKT under the symbol "MPO".

Results of Operations

Oil, NGLs and Natural Gas 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. 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
- our revenues and profitability.

Table of Contents

Average market prices for oil and NGLs decreased significantly in the last part of 2014 and continue to remain depressed compared to previous highs. 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."

The following table sets forth information regarding our oil, natural gas and NGL revenues for the Successor Period, Predecessor Period and the years ended December 31, 2015 and 2014 (in thousands):

	Crude Oil	Natural Gas	NGLs	Total
Revenues for the year ended December 31, 2014	$ 466,655	$ 99,204	$ 87,771	$ 653,630
Changes due to volumes	(15,923)	8,100	878	(6,945)
Changes due to price	(233,096)	(40,481)	(50,400)	(323,977)
Revenues for the year ended December 31, 2015	$ 217,636	$ 66,823	$ 38,249	$ 322,708
Changes due to volumes	(69,486)	(10,827)	(7,708)	(88,021)
Changes due to price	(35,522)	(7,678)	(3,068)	(46,268)
Revenues for the Predecessor Period	$ 112,628	$ 48,318	$ 27,473	$ 188,419
Changes due to volumes	(113,672)	(50,479)	(29,379)	(193,530)
Changes due to price	26,593	15,796	10,297	52,686
Revenues for the Successor Period	$ 25,549	$ 13,635	$ 8,391	$ 47,575

Oil, Natural Gas and NGL Pricing

The following table sets forth information regarding average realized sales prices for the Successor Period, Predecessor Period and the years ended December 31, 2015 and 2014:

	Successor	Predecessor			
	For the Period October 21, 2016 Through December 31, 2016	For the Period January 1, 2016 Through October 20, 2016	Years Ended December 31, 2015	% Change	2014
AVERAGE SALES PRICES:					
Oil, without realized derivatives (per Bbl)	$ 46.96	$ 37.99	$ 45.40	(50)%	$ 90.71
Oil, with realized derivatives (per Bbl)	$ 46.96	$ 37.99	$ 74.74	(15)%	$ 87.40
Natural gas liquids, without realized derivatives (per Bbl)	$ 19.55	$ 14.22	$ 15.46	(57)%	$ 36.31
Natural gas liquids, with realized derivatives (per Bbl)	$ 19.55	$ 14.22	$ 15.46	(58)%	$ 36.40
Natural gas, without realized derivatives (per Mcf)	$ 2.76	$ 2.08	$ 2.35	(41)%	$ 3.97
Natural gas, with realized derivatives (per Mcf)	$ 2.76	$ 2.08	$ 3.30	(16)%	$ 3.91

Crude Oil Prices

The majority of our crude oil production is sold at prevailing market prices with an adjustment for transportation and quality. The market pricing for oil fluctuates in response to many factors that are outside of our control such as supply and demand fluctuations, pipeline and refinery outages, weather patterns and global events and economics.

Historically, we utilized fixed price swaps to manage the impact of changing crude prices. All of our derivatives expired at December 31, 2015 and we did not enter into additional derivatives for 2016.

Table of Contents

Subsequent to December 31, 2016, we entered into various oil derivative contracts that extend through March 2018, which are summarized as follows:

	Quarter Ended March 31, 2017	Quarter Ended June 30, 2017	Quarter Ended September 30, 2017	Quarter Ended December 31, 2017	Quarter Ended March 31, 2018
NYMEX WTI					
Fixed swaps					
Hedge position (Bbls)	105,500	227,500	207,000	207,000	
Weighted average strike price	$ 55.17	$ 55.12	$ 55.29	$ 55.29	$
Collars					
Hedge position (Bbls)	74,500	136,500	46,000	46,000	
Weighted average ceiling price	$ 59.68	$ 59.73	$ 60.00	$ 60.00	$
Weighted average floor price	$ 50.00	$ 50.00	$ 50.00	$ 50.00	$
Three way collars					
Hedge position (Bbls)			115,000	115,000	135,000
Weighted average ceiling price	$	$	$ 62.80	$ 62.80	$ 63.50
Weighted average floor price	$	$	$ 50.00	$ 50.00	$ 50.00
Weighted average sub-floor price	$	$	$ 40.00	$ 40.00	$ 40.00

Natural Gas Prices

Natural gas prices are subject to variances based on local supply and demand conditions as well as rapidly evolving market conditions. Our current natural gas sales contracts are based upon index pricing that varies widely as a result of many factors, such as geography and supply and demand. Our natural gas is sold on a monthly weighted average sales price utilizing a combination of first of month index and daily index pricing for a given period.

Historically, we utilized fixed price swaps to manage the impact of changing natural gas prices. All of our derivatives expired at December 31, 2015 and we did not enter into additional derivatives for 2016.

Subsequent to December 31, 2016, we entered into various natural gas derivative contracts that extend through March 2018, which are summarized as follows:

	Quarter Ended March 31, 2017	Quarter Ended June 30, 2017	Quarter Ended September 30, 2017	Quarter Ended December 31, 2017	Quarter Ended March 31, 2018
NYMEX HENRY HUB					
Fixed swaps					
Hedge position (MMBtu)		2,912,000	2,944,000	992,000	
Weighted average strike price	$	$ 3.38	$ 3.38	$ 3.38	$
Collars					
Hedge position (MMBtu)	1,298,000				
Weighted average ceiling price	$ 3.70	$	$	$	$
Weighted average floor price	$ 3.10	$	$	$	$
Three way collars					
Hedge position (MMBtu)				610,000	900,000
Weighted average ceiling price	$	$	$	$ 4.30	$ 4.30
	$	$	$	$ 3.25	$ 3.25

Weighted average floor price					
Weighted average sub-floor price	$	$	$	$ 2.50	$ 2.50

Table of Contents

NGL Prices

Our NGL production is sold under contracts with prices at market indices less the costs for transportation and fractionation. The market price of our NGL production, which primarily consists of ethane, propane, butane, iso-butane and natural gasoline, can be impacted by local market conditions, such as fractionation availability, and business conditions of the end users of such NGL products, such as chemical companies, plastic manufacturers and propane dealers.

Oil Revenues

Successor Period

For the Successor Period, our oil sales revenues were $25.5 million. Our oil revenue was comprised of $20.5 million from our Mississippian Lime assets and $5.0 million from our Anadarko Basin assets.

Predecessor Period

For the Predecessor Period, our oil sales revenues were $112.6 million. Our oil revenue was comprised of $91.5 million from our Mississippian Lime assets and $21.1 million from our Anadarko Basin assets.

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. Of the $217.6 million in total oil sales revenues, $169.2 million was our Mississippian Lime assets, $43.7 million was from our Anadarko Basin assets and $4.7 million was from our Gulf Coast assets.

Natural Gas Revenues

Successor Period

For the Successor Period, our natural gas sales revenues were $13.6 million. Our natural gas revenue was comprised of $11.8 million from our Mississippian Lime assets and $1.8 million from our Anadarko Basin assets.

Predecessor Period

For the Predecessor Period, our natural gas sales revenues were $48.3 million. Our natural gas revenue was comprised of $42.6 million from our Mississippian Lime assets and $5.7 million from our Anadarko Basin assets.

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

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. Of the $66.8 million in total natural gas sales revenues, $56.5 million was from our Mississippian Lime assets, $10.1 million was from our Anadarko Basin assets and $0.2 million was from our Gulf Coast assets.

Table of Contents

NGL Revenues

Successor Period

For the Successor Period, our NGLs sales revenues were $8.4 million. Our NGL revenue was comprised of $6.8 million from our Mississippian Lime assets and $1.6 million from our Anadarko Basin assets.

Predecessor Period

For the Predecessor Period, our NGLs sales revenues were $27.5 million. Our NGL revenue was comprised of $22.5 million from our Mississippian Lime assets and $5.0 million from our Anadarko Basin assets.

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

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. Of the $38.2 million in total NGLs revenues, $30.7 million was from our Mississippian Lime assets, $7.0 million was from our Anadarko Basin assets and $0.5 million was from our Gulf Coast assets.

Gains/Losses on Commodity Derivative Contracts Net

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 ("MTM") value at the end of each month. Cash flows associated with derivative financial instruments are reflected in cash flows from operations in our consolidated statement of cash flows. We had no open derivative contracts at December 31, 2015 or December 31, 2016. However, subsequent to December 31, 2016, we did enter into various derivative contracts for 2017 and the first quarter of 2018.

Table of Contents

The following table sets forth the components of our realized gain on commodity derivative contracts, net in our consolidated statements of operations (in thousands):

	Successor	Predecessor				
	For the Period October 21,2016 Through December 31, 2016	For the Period January 1, 2016 Through October 20, 2016	Year Ended December 31,			
			2015		2014	
	Realized Gain	Realized Gain	Realized Gain	Average Sales Price	Realized Gain/(Loss)	Average Sales Price
Oil commodity contracts	$	$	$ 140,656	$ 74.74	$ (17,060)	$ 87.40
Natural gas liquids commodity contracts					217	36.40
Natural gas commodity contracts			27,013	3.30	(1,489)	3.91
Total cash receipts (payments)	**$**	**$**	**$ 167,669**		**$ (18,332)**	

Cash settlements, as presented in the table above, represent realized gains/losses 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. At December 31, 2016, we had no derivative instruments.

Other Revenues

Successor Period

For the Successor period, other revenues were $1.0 million. Other revenue for the Successor Period was primarily comprised of fees charged to outside working interest owners for salt water disposal.

Predecessor Period

For the Predecessor Period, other revenues were $4.8 million. Other revenue for the Predecessor Period was primarily comprised of fees charged to outside working interest owners for salt water disposal.

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

Our other revenues were $1.5 million and $1.4 million for the years ended December 31, 2015 and 2014, respectively. Other revenue for the years ended December 31, 2015 and 2014 was primarily comprised of payments received from a third party for the extraction of iodine from our produced salt water.

Table of Contents

Oil, Natural Gas and NGL Production

	Successor	Predecessor			
	For the Period October 21, 2016 Through December 31, 2016	For the Period January 1, 2016 Through October 20, 2016	Years Ended December 31,		
			2015	% Change	2014
PRODUCTION DATA:					
Oil (Bbls/d)					
Mississippian Lime	6,048	8,156	10,194	21.2%	8,411
Anadarko Basin	1,508	1,927	2,680	(33.2)%	4,014
Gulf Coast			260	(84.4)%	1,669
Natural gas liquids (Bbls/d)					
Mississippian Lime	4,843	5,326	5,307	19.6%	4,437
Anadarko Basin	1,118	1,247	1,388	(21.4)%	1,766
Gulf Coast			81	(80.7)%	419
Natural gas (Mcf/d)					
Mississippian Lime	58,816	68,107	64,688	24.3%	52,024
Anadarko Basin	9,903	10,856	12,921	(13.5)%	14,930
Gulf Coast			208	(86.8)%	1,574
Combined (Boe/d)					
Mississippian Lime	20,694	24,833	26,282	22.1%	21,518
Anadarko Basin	4,277	4,983	6,222	(24.8)%	8,269
Gulf Coast			376	(84.0)%	2,350

Crude Oil Production

Successor Period

For the Successor Period, our oil volumes sold averaged 7,556 Bbls/d, comprised of 6,048 Bbls/d from our Mississippian Lime assets and 1,508 Bbls/d from our Anadarko Basin assets.

Predecessor Period

For the Predecessor Period, our oil volumes sold averaged 10,083 Bbls/d, comprised of 8,156 Bbls/d from our Mississippian Lime assets and 1,927 Bbls/d from our Anadarko Basin assets.

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

The decrease in oil volumes sold was due to a decrease of 1,409 Bbls/d of production volumes from the Gulf Coast due to the sale of our remaining producing properties in Louisiana in April of 2015, as well as a decrease of 1,334 Bbls/d 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 1,783 Bbls/d due to increased drilling activity.

NGL Production

Successor Period

For the Successor Period, our NGLs volumes sold were 5,961 Bbls/d, comprised of 4,843 Bbls/d from our Mississippian Lime assets and 1,118 Bbls/d from our Anadarko Basin assets.

Table of Contents

Predecessor Period

For the Predecessor Period, our NGLs volumes sold were 6,573 Bbls/d, comprised of 5,326 Bbls/d from our Mississippian Lime assets and 1,247 Bbls/d from our Anadarko Basin assets.

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

The increase in NGLs volumes sold was attributable to an increase of 870 Bbls/d of production volumes from our Mississippian Lime assets, partially offset by decreases in Anadarko Basin production of 378 Bbls/d and Gulf Coast production of 338 Bbls/d.

Natural Gas Production

Successor Period

For the Successor Period, our natural gas volumes sold were 68,719 Mcf/d, comprised of 58,816 Mcf/d from our Mississippian Lime assets and 9,903 Mcf/d from our Anadarko Basin assets.

Predecessor Period

For the Predecessor Period, our natural gas volumes sold were 78,963 Mcf/d, comprised of 68,107 Mcf/d from our Mississippian Lime operations and 10,856 Mcf/d from our Anadarko Basin assets.

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

The increase in natural gas volumes sold was attributable to an increase of 12,664 Mcf/d of production volumes from our Mississippian Lime assets, partially offset by decreases of 2,009 Mcf/d in production from our Anadarko Basin assets and 1,366 Mcf/d from our Gulf Coast assets.

Expenses

	Successor	Predecessor			Successor	Predecessor		
	For the Period October 21, 2016 Through December 31, 2016	For the Period January 1, 2016 Through October 20, 2016	Years Ended December 31, 2015	2014	For the Period October 21, 2016 Through December 31, 2016	For the Period January 1, 2016 Through October 20, 2016	Years Ended December 31, 2015	2014
	(in thousands)	(in thousands)			(per Boe)	(per Boe)		
EXPENSES:								
Lease operating and workover	$ 15,324	$ 52,803	$ 81,473	$ 79,598	$ 8.52	$ 6.02	$ 6.79	$ 6.79
Gathering and transportation	3,194	14,362	15,546	13,404	1.78	1.64	1.30	1.14
Severance and other taxes	1,286	5,210	8,605	24,266	0.72	0.59	0.72	2.07
Asset retirement accretion	210	1,414	1,610	1,706	0.12	0.16	0.13	0.15
Depreciation, depletion, and amortization	12,974	62,302	198,643	269,935	7.22	7.11	16.55	23.01
Impairment of oil and gas properties		232,108	1,625,776	86,471		26.48	135.47	7.37
General and administrative	4,864	22,362	38,703	48,733	2.71	2.55	3.22	4.15
Acquisition and transaction costs			330	4,129			0.03	0.35
Debt restructuring costs and advisory fees		7,590	36,141			0.87	3.01	
Other			2,121	5,108			0.18	0.44

Total expenses	**$ 37,852**	**$ 398,151**	**$ 2,008,948**	**$ 533,350**	**$ 21.07**	**$ 45.42**	**$ 167.40**	**$ 45.47**

Lease Operating and Workover

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 and compressor rental costs, as well as variable costs resulting from additional wells and production, such as chemicals and electricity. 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.

Successor Period

For the Successor Period, our lease operating and workover expenses were $15.3 million at a cost of $8.52 per Boe. Lease operating and workover expenses for the Successor Period were impacted by weather disruptions, which lowered production and increased costs during the period.

Predecessor Period

For the Predecessor Period, our lease operating and workover expenses were $52.8 million at a cost of $6.02 per Boe.

Year Ended December 31, 2015 as Compared to 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. The increase in workover expenses during the year is due to increased production optimization projects, primarily in the Anadarko Basin. Total lease operating and workover expenses increased for the year ended December 31, 2015, while the per unit amount remained unchanged at $6.79 per Boe.

Gathering and Transportation

Gathering and transportation costs are incurred for the movement of natural gas to the contractual delivery point. For the Successor Period, Predecessor Period and the years ended December 31, 2015 and 2014, these costs relate to the amended gas transportation, gathering and processing contract which commenced during the third quarter of 2013 in our Mississippian Lime assets.

Successor Period

For the Successor Period, our gathering and transportation expenses were $3.2 million at a cost of $1.78 per Boe.

Predecessor Period

For the Predecessor Period, our gathering and transportation expenses were $14.4 million at a cost of $1.64 per Boe.

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

The increase in gathering and transportation costs was primarily attributable to a 13.6% increase in natural gas production volumes for the year ended December 31, 2015.

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

Table of Contents

are property taxes assessed based on the value of property and are also included in this expense category.

	Successor	Predecessor		
	For the Period October 21, 2016 Through December 31, 2016	For the Period January 1, 2016 Through October 20, 2016	Years Ended December 31, 2015	Years Ended December 31, 2014
	(in thousands)	(in thousands)		
Total oil, natural gas, and natural gas liquids sales	**$ 47,575**	**$ 188,419**	**$ 322,708**	**$ 653,630**
Severance taxes	1,093	4,058	5,754	17,723
Ad valorem and other taxes	193	1,152	2,851	6,543
Severance and other taxes	**$ 1,286**	**$ 5,210**	**$ 8,605**	**$ 24,266**
Severance taxes as a percentage of sales	**2.3%**	**2.2%**	**1.8%**	**2.7%**
Severance and other taxes as a percentage of sales	**2.7%**	**2.8%**	**2.7%**	**3.7%**

Successor Period

For the Successor Period, our severance and other tax expenses were $1.3 million or 2.7% of sales. Severance tax was $1.1 million or 2.3% of sales during the Successor Period.

Predecessor Period

For the Predecessor Period, our severance and other tax expenses were $5.2 million or 2.8% of sales. Severance tax was $4.1 million or 2.2% of sales during the Predecessor Period.

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

The decrease in severance taxes was primarily due to lower realized pricing in the 2015 period and the sale of our Louisiana (or Gulf Coast) properties which had higher effective severance tax rates than our Mississippian Lime and Anadarko Basin properties. Ad valorem taxes decreased due to a significant decrease in the value of our proved oil and gas reserves from 2014 to 2015.

Depreciation, Depletion and Amortization ("DD&A")

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.

Successor Period

For the Successor Period, our DD&A expenses were $13.0 million at a cost of $7.22 per Boe.

Predecessor Period

For the Predecessor Period, our DD&A expenses were $62.3 million at a cost of $7.11 per Boe.

Table of Contents

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

The decrease in 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.

Impairment of Oil and Gas Properties

As we account for our oil and gas properties under the full cost method, we are required to perform a full-cost ceiling test 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 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.

Successor Period

For the Successor Period, we did not incur any impairments of oil and gas properties.

Predecessor Period

For the Predecessor Period, our impairment of oil and gas properties was $232.1 million. The impairment expense recognized in the Predecessor 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, which are a significant input into the calculation of the discounted future cash flows associated with our proved oil and gas reserves.

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

For the year ended December 31, 2015, our impairment of oil and gas properties was $1.6 billion. 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, which are a significant input into the calculation of the discounted future cash flows associated with our proved oil and gas reserves.

General and Administrative ("G&A")

G&A expense consists of, among other items, 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.

Successor Period

For the Successor Period, our G&A expense was $4.9 million at a cost of $2.71 per Boe. G&A for the Successor Period includes primarily professional fees and credits to previously incurred professional fees for reorganization type items, resulting in credit of $1.1 million, and non-cash stock based compensation expense for awards issued pursuant to the 2016 LTIP of $2.9 million.

Table of Contents

Predecessor Period

For the Predecessor Period, our G&A expense was $22.4 million at a cost of $2.55 per Boe. G&A for the Predecessor Period includes $1.3 million of accelerated expense associated with cancelled stock compensation awards and $1.6 million in severance costs.

Year Ended December 31, 2015 as Compared to 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.

Acquisition and Transaction Costs

Acquisition and transaction costs are costs we have incurred as a result of acquisitions or as a result of asset disposition transactions and include finders' fees, advisory, legal, accounting, valuation and other professional and consulting fees and other acquisition or disposition related general and administrative costs. Acquisition and transaction related costs are expensed as incurred and as services are received.

Successor Period

For the Successor Period, we did not incur any acquisition and transaction costs.

Predecessor Period

For the Predecessor Period, we did not incur any acquisition and transaction costs.

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

For the year ended December 31, 2015, acquisition and transaction costs are related to our expenses incurred with the Dequincy Divestiture. For the year ended December 31, 2014, acquisition and transaction costs primarily represent our expenses related to the Pine Prairie Disposition.

Debt Restructuring Costs and Advisory Fees

Debt restructuring costs and advisory fees include costs incurred for legal, financing and advisor costs associated with specific transactions, such as troubled debt restructuring, or costs incurred prior to the Petition Date.

Successor Period

For the Successor Period, we did not incur any debt restructuring costs and advisory fees.

Predecessor Period

For the Predecessor Period, we incurred $7.6 million of debt restructuring costs and advisory fees related to our bankruptcy and restructuring process prior to the Petition Date.

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.

Table of Contents

Other

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.

Successor Period

For the Successor Period, we did not incur any other expense.

Predecessor Period

For the Predecessor Period, we did not incur any other expense.

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

For the year ended December 31, 2015, other expenses relate to the loss on disposal of, or market value adjustments to, field equipment inventory deemed no longer useful to current operations. For the year ended December 31, 2014, other expenses relate to the loss on disposal of, or market value adjustments to, field equipment inventory deemed no longer useful to current operations as well as penalty fees associated with the early termination of a drilling rig contract.

Other Income/Expense

	Successor	Predecessor		
	For the Period October 21, 2016 Through December 31, 2016	For the Period January 1, 2016 Through October 20, 2016	Years Ended December 31, 2015	2014
	(in thousands)	(in thousands)		
OTHER INCOME (EXPENSE)				
Interest income	$	$ 81	$ 115	$ 39
Interest expense	(1,409)	(70,019)	(182,955)	(149,962)
Amortization of deferred financing costs	(62)	(4,587)		
Amortization of deferred gain		8,246	14,948	
Capitalized interest	728		4,859	12,414
Interest expense net of amounts capitalized (Predecessor Period excludes interest expense of $89.5 million on senior and secured notes)	(743)	(66,360)	(163,148)	(137,548)
Reorganization items		1,594,281		
Total other income (expense)	**$ (743)**	**$ 1,528,002**	**$ (163,033)**	**$ (137,509)**

Interest Expense

Prior to the Effective Date, we had substantial long-term debt in the form of our 2020 Senior Notes, 2021 Senior Notes, Second Lien Notes and Third Lien Notes. Additionally, we financed a portion of our working capital requirements and capital expenditures with borrowings under our RBL. Included within interest expense for periods prior the Successor Period is the amortization of the related deferred financing costs, net of any amounts capitalized to unproved properties, and amortization of the deferred gain recognized on the restructuring of our debt, which occurred in the second quarter of 2015 and was being recognized as a reduction to interest expense using the effective interest method.

Successor Period

For the Successor Period, we incurred $1.4 million of interest expense related to our Exit Facility which bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. At December 31, 2016, the weighted average interest rate was 5.50%. We also capitalized $0.7 million of interest expense to our unevaluated oil and gas properties during the period.

Predecessor Period

For the Predecessor Period, we incurred $70.0 million of interest expense. During the Predecessor Period, we reclassified our Senior Notes, Second Lien Notes and Third Lien Notes to liabilities subject to compromise in connection with the Chapter 11 Cases. As such, we ceased recognizing interest expense for all debt except amounts outstanding under the RBL beginning at the Petition Date. Contractual interest not reflected in the consolidated statements of operations was approximately $89.5 million, which represents interest expense incurred subsequent to the Petition Date. No interest expense was capitalized during the period due to the transfer of all balances related to unevaluated property to the full cost pool at December 31, 2015.

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

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 bore interest at 10.0% and a portion of the proceeds were used to repay outstanding borrowings under the RBL. Additionally, the Third Lien Notes bore 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 RBL. The increase in 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.

Reorganization Items, Net

Reorganization items, net, represent the direct and incremental costs of being in bankruptcy from the Petition Date through the Effective Date, and include such items as professional fees, gains from pre-petition liability claim adjustments and losses related to terminated contracts that are probable and can be estimated.

Successor Period

For the Successor Period, we did not recognize any reorganization items.

Predecessor Period

For the Predecessor Period, we recognized $1.6 billion of reorganization income related to our emergence from bankruptcy. Reorganization items include a $1.3 billion gain on the settlement of liabilities subject to compromise, $111.4 million of adjustments to unamortized gains on troubled debt restructuring related to the issuance of the Second Lien Notes and the Third Lien Notes, $23.4 million of adjustments to unamortized debt issuance costs, $38.8 million of professional fees incurred and $274.2 million of fresh start adjustments and other reorganization items.

Table of Contents

Provision for Income Taxes

Successor Period

For the Successor Period, we had no provision for income taxes due to the change in our valuation allowance recorded against our net deferred tax assets.

Predecessor Period

For the Predecessor Period, we had no provision for income taxes due to the change in our valuation allowance recorded against our net deferred tax assets.

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.

Capital Resources, Uses and Liquidity

Overview

Our decisions regarding capital structure, hedging and drilling are based upon many factors, including anticipated future commodity pricing, expected economic conditions and recoverable reserves. The unexpected substantial decrease in oil and gas prices that began in the second half of 2014 and continued throughout 2015 and 2016 resulted in materially lower operating cash flows than we had anticipated. In addition, all of our hedging contracts expired during 2015, and as a result, we did not receive any cash derivative settlements during the Successor Period or Predecessor Period, which also negatively impacted cash provided by operations for those periods as compared to our historical operating cash flows. As a result of these factors, our debt service requirements became unsustainable and we filed for a reorganization under Chapter 11 of the Bankruptcy Code on the Petition Date. On the Effective Date, we satisfied the conditions to effectiveness set forth in the Confirmation Order and in the Plan. As a result, our Plan became effective in accordance with its terms and we emerged from the Chapter 11 Cases at that time. For additional information, please see " Note 2. Emergence from Voluntary Reorganization under Chapter 11 Proceedings" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

On the Effective Date, $1.8 billion of debt was extinguished in accordance with the Plan, the Second Lien Notes were exchanged for a cash payment of $60.0 million and 96.25% of our reorganized equity in the form of common stock, and the Third Lien Notes and Senior Notes were exchanged for a combination of our reorganized equity in the form of common stock and warrants to acquire additional common shares of the reorganized equity and we entered into an Exit Facility providing up to $170.0 million of credit. Additionally, we paid down $81.3 million owed under the RBL as well as an additional payment of $40.0 million to lenders under our Exit Facility. As a result of our restructuring, we estimate cash paid for interest will decrease from an average of approximately $173.7 million per year to approximately $7.0 million per year, a cash interest savings of approximately $166.7 million per year.

Table of Contents

The following table provides adjustments that reflect the consummation of transactions contemplated by the Plan, as of the Effective Date (excluding the Exit Facility):

	As of October 21, 2016 Predecessor	Reorganization Adjustments	As of October 21, 2016 Successor
		(in thousands)	
Unsecured Notes:			
2020 Senior Notes	$ 293,625	$ (293,625)	$
2021 Senior Notes	347,652	(347,652)	
Total Unsecured Notes	$ 641,277	$ (641,277)	$
Secured Notes:			
Second Lien Term Loan	$ 625,000	$ (625,000)	$
Third Lien Term Loan	529,653	(529,653)	
Total Secured Notes	$ 1,154,653	$ (1,154,653)	$
Total Debt (excluding Exit Facility)	**$ 1,795,930**	**$ (1,795,930)**	**$**

Historically, our primary sources of liquidity have been our operating cash flows, proceeds from divestitures, cash on hand and cash available from borrowings under the Exit Facility. We anticipate our operating cash flows and cash on hand will be our primary sources of liquidity subsequent to the Effective Date, although we may seek to supplement our liquidity through divestitures, additional borrowings or debt or equity securities offerings as circumstances and market conditions dictate. We believe the combination of these sources of liquidity will be adequate to fund anticipated capital expenditures, service our existing debt and remain compliant with all other contractual commitments.

Our cash flows from operations are impacted by various factors, the most significant of which is the market pricing for oil, natural gas and NGLs. The pricing for these commodities is volatile, and the factors that impact such market pricing are global and therefore outside of our control. As a result, it is not possible for us to precisely predict our future cash flows from operating revenues due to these market forces.

We have historically utilized derivatives to alleviate some of the volatility in market pricing. While we did not utilize any derivatives throughout 2016, we did enter into various derivatives subsequent to December 31, 2016, which are summarized in " Note 6. Risk Management and Derivatives Instruments" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Our Capital Requirements

The following table summarizes factors affecting our liquidity (in thousands):

	Successor	Predecessor	
	December 31, 2016	December 31, 2015	December 31, 2014
Cash and cash equivalents	$ 76,838	$ 81,093	$ 11,557
Net working capital, including debt classified as current	67,637	(1,838,758)	21,649
Net working capital, excluding debt classified as current	67,637	52,186	21,649
Total long-term debt	128,059		1,706,532
Available borrowing capacity		249,159	88,361

Table of Contents

At December 31, 2016, our liquidity was $76.8 million, composed entirely of our cash and cash equivalents. During the Successor Period and the Predecessor Period, we incurred operational capital expenditures of $16.8 million and $123.6 million, respectively, which consisted primarily of the following (in thousands):

	Successor		Predecessor	
	For the Period October 21, 2016 through December 31, 2016		For the Period January 1, 2016 through October 20, 2016	
Drilling and completion activities	$	16,100	$	116,764
Acquisition of acreage and seismic data		702		6,869
Operational capital expenditures incurred		**16,802**		**123,633**
Capitalized G&A, Office, ARO and Other		1,608		4,904
Capitalized interest		728		
Total capital expenditures incurred	**$**	**19,138**	**$**	**128,537**

Operational capital expenditures were incurred in the following areas for the Successor Period and Predecessor Period (in thousands):

	Successor		Predecessor	
	For the Period October 21, 2016 through December 31, 2016		For the Period January 1, 2016 through October 20, 2016	
Mississippian Lime	$	16,526	$	122,329
Anadarko Basin		276		1,304
Operational capital expenditures incurred	**$**	**16,802**	**$**	**123,633**

As of December 31, 2016, we had one drilling rig in operation in the Mississippian Lime. Subject to the terms of our Exit Facility, we currently anticipate operating one rig in the Mississippian Lime and investing between $90.0 million and $100.0 million of capital for exploration, development and lease and seismic acquisition during the year ended December 31, 2017. We expect cash generated by operations and cash on hand to be sufficient to fully fund our expected capital requirements.

Significant Sources of Capital

Exit Facility

At December 31, 2016, in addition to cash on hand of $76.8 million, we maintained the Exit Facility. The Exit Facility has a current borrowing base of $170.0 million and no borrowing base redeterminations are to occur until April 2018 (provided certain conditions are met) with semiannual borrowing base redeterminations each year on April 1 and October 1 thereafter. Until April 2018, unless the borrowing base is redetermined earlier, the amount available to be drawn under the Exit Facility is reduced by $40.0 million, and thereafter, we must maintain liquidity (as defined therein) equal to at least 20.0% of the effective borrowing base. At December 31, 2016, we had $128.1 million drawn on the Exit Facility and outstanding letters of credit obligations totaling $1.9 million. As a result, at December 31, 2016 we had no amount of availability on the Exit Facility.

The Exit Facility matures on September 30, 2020 and borrowings thereunder are secured by (i) first-priority mortgages on at least 95% of the our oil and gas properties, (ii) all other presently

Table of Contents

owned or after-acquired property (including but not limited to as-extracted collateral, accounts receivable, inventory, equipment, general intangibles, investment property, intellectual property, real property and the proceeds of the foregoing) and (iii) a perfected pledge on all equity interests. The Exit Facility bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. At December 31, 2016, the weighted average interest rate was 5.50%.

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

Debt Covenants

In addition to the aforementioned liquidity covenant, the Exit Facility also contains various other financial covenants, including an EBITDA to interest expense coverage ratio limitation of 3.00:1.00, a ratio limitation of Total Net Indebtedness (as defined in the Exit Facility) to EBITDA of not more than 2.25:1.00 through April 1, 2018 and not more than 3.00:1.00 thereafter, and a capital expenditure limitation of $50.0 million for the 6 months ended December 31, 2016, $81.0 million for the year ended December 31, 2017, $85.0 million for the year ended December 31, 2018 and $78.0 million for the year ended December 31, 2019. The Exit Facility is also subject to a variety of other terms and conditions including conditions precedent to funding, restrictions on the payment of dividends and various other covenants and representations and warranties. As of December 31, 2016, we were in compliance with our debt covenants.

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 (in thousands):

	Successor	**Predecessor**	**For the Years Ended December 31,**	
	For the Period October 21, 2016 through December 31, 2016	**For the Period January 1, 2016 through October 20, 2016**	**2015**	**2014**
Net cash provided by operating activities	$ 23,644	$ 61,997	$ 213,383	$ 351,544
Net cash used in investing activities	(23,346)	(133,307)	(294,556)	(404,264)
Net cash provided by financing activities		66,757	150,709	31,114
Net change in cash	**$ 298**	**$ (4,553)**	**$ 69,536**	**$ (21,606)**

Table of Contents

Cash flows provided by operating activities

Net cash provided by operating activities was $23.6 million, $62.0 million, $213.4 million and $351.5 million for the Successor Period, Predecessor Period and the years ended December 31, 2015 and 2014, 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 attributable to lower commodity prices, partially offset by increased settlements of derivatives of $186.0 million.

Cash flows used in investing activities

We had net cash used in investing activities of $23.3 million, $133.3 million, $294.6 million and $404.3 million for the Successor Period, Predecessor Period and the years ended December 31, 2015 and 2014, respectively. Net cash used in investing activities for the Successor Period and Predecessor Period represents cash invested in property and equipment.

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 8. Acquisition 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) and $1.4 million in other asset sales.

Cash flows provided by financing activities

Net cash provided by financing activities was $66.8 million, $150.7 million and $31.1 million for the Predecessor Period and the years ended December 31, 2015 and 2014, respectively. Net cash provided by financing activities for the Predecessor Period primarily represents borrowings from the RBL of $249.4 million offset partially by repayments of the RBL of $121.3 million and repayments of the Second Lien Notes of $60.0 million.

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 RBL of $33.0 million. These proceeds were partially offset by repayments on the RBL 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.

Table of Contents

Other Items

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2016 (in thousands):

	Payments Due by Period				
	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Reserves based revolving credit facility(1)	$ 128,059	$	$	$ 128,059	$
Non-cancellable office lease commitments(2)	6,631	642	1,997	1,392	2,600
Asset retirement obligations(3)	14,200				14,200
Net minimum commitments(4)	**$ 148,890**	**$ 642**	**$ 1,997**	**$ 129,451**	**$ 16,800**

---

(1) Amount excludes interest on our reserves based revolving credit facility as both the amount borrowed and applicable interest rate is variable. As of December 31, 2016, we had drawn down $128.1 million on our reserves based revolving credit facility and had $1.9 million of outstanding letters of credit. See " Note 10. Debt" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K for further information.

(2) See " Note 16. Commitments and Contingencies" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K, for a description of operating lease 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 9. Asset Retirement Obligations" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

(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 US 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:

Fresh Start Accounting

Upon our emergence on the Effective Date, we adopted fresh start accounting as required by US GAAP. We qualified for fresh start accounting because (i) the holders of existing voting shares of

the pre-emergence debtor-in-possession received less than 50% of the voting shares of the post-emergence successor entity and (ii) the reorganization value of our assets immediately prior to confirmation was less than the post-petition liabilities and allowed claims. We applied fresh start accounting as of the Effective Date. Adopting fresh start accounting results in a new reporting entity for financial reporting purposes with no beginning retained earnings or deficit and all of our assets and liabilities marked to fair value as of the Effective Date. As a result of the application of fresh start accounting, as well as the effects of the implementation of the Plan, our consolidated financial statements on or after the Effective Date are not comparable with our consolidated financial statements prior to that date.

There are various assumptions we made in determining the fair values of our assets and liabilities at the Effective Date. The most significant assumptions involve the estimated fair values of our oil and gas properties. To determine the fair values of these properties, we prepared estimates of oil, natural gas and NGL reserves as of the Effective Date. The engineering assumptions contained within this reserves report were consistent with both (i) previous engineering assumptions made by us when preparing reserve reports in prior years and (ii) assumptions promulgated by the SEC. These assumptions include type curves and analogous reservoir characteristics determined utilizing electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data, to name a few. We then utilized an outside third-party expert to assist us in the preparation of a valuation report utilizing assumptions consistent with a market participant. This valuation report utilized the income approach in determining the fair value of our oil and gas reserves, excluding possible reserves, for which the market approach was utilized. The income approach involves the projection of cash flows a market participant would expect an asset or business to generate over its remaining useful life. These projected cash flows from our oil and gas properties are adjusted for risk based upon the reserves category before being further adjusted for estimates of various indirect costs associated with the production of such reserves, such as general and administrative costs, income taxes and the impact of inflation. These cash flows are projected on an annual basis for a discrete period of time and then converted to their present value using a rate of return that captures the relevant risk of achieving the projected cash flows, which is based upon an estimated required return of capital for debt and equity for a market participant. Finally, the present value of the residual value, or terminal value, is added to these discrete cash flows to arrive at the estimate of total value. The market approach, which was utilized to value possible reserves, measures value through the use of prices, market multiples and other relevant information involving identical or comparable assets or business interests, which were largely determined based upon widely utilized industry sources and other relevant data in the respective area.

Unproved properties generally represent the value of probable and possible reserves. Due to the inherent nature of such reserves, probable reserve estimates are more imprecise than those of proved reserves. In order to compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net revenues of probable reserves are reduced by an appropriate risk-weighting factor in each particular instance. Possible reserves were not valued utilizing a discounted cash flow approach, but rather through the use of industry data and specific transactions utilizing the market approach.

Full Cost Method of Accounting and Proved Reserve Estimates

Proved oil and gas reserves are the estimated quantities of crude oil, NGLs and natural gas that geological and engineering data demonstrates 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.

Our estimates of reserves 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 the ceiling calculation dictates the use of prices that are not representative of future prices and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and gas prices have historically been cyclical and, for any particular 12-month period, can be either higher or lower than our long-term price forecast, which is a more appropriate input for estimating fair value. Therefore, oil and gas property write-downs that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves. Because of the volatile nature of oil and gas prices, it generally is not possible to predict the timing or magnitude of full cost write-downs. However, based upon commodity pricing for the first quarter of 2017 and industry expectations of future commodity prices, we do not expect to recognize a full cost impairment in 2017.

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

Compensation expense associated with granted stock options and restricted stock units (excluding restricted stock units containing a market condition) is determined based on our estimate of the fair value of those awards at the initial grant date.

The fair value of restricted stock units is based on the fair value of an unrestricted share of common stock at the grant date. We utilize the Black-Scholes-Merton option pricing model to measure the fair value of stock options. Key inputs used in the option pricing model include the risk-free interest rate, the expected volatility of the underlying stock and the expected life of the award. Restricted stock units containing a market condition are treated as a liability award and the fair value is based upon a Monte Carlo simulation utilizing assumptions for expected volatility, risk-free interest rate and expected life that are updated quarterly until the award vests or expires. The key assumptions used in measuring stock compensation expense for all awards are included in " Note 12. Equity and Share-Based Compensation" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K. 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 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, 2016, 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 $(3.0) million, while a decrease of 5 years in the estimated settlement date would have an impact of $3.6 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 regularly 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. The ultimate realization of our deferred tax assets is dependent upon the generation of taxable income during future periods. In light of a lack of positive evidence, we have recorded a full valuation allowance against our net deferred tax assets of $160.8 million as of December 31, 2016.

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 Financial Accounting Standards Board ("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

Table of Contents

statements regarding the nature, timing and uncertainty of revenues. ASU 2014-09 requires an entity to perform the following steps:

Step 1 Identify the contract with a customer: A contract between two or more parties creates enforceable rights and obligations. A contract that identifies the relevant parties and has been approved by those parties, identifies the payment terms, has commercial substance and results in a probable collection of future consideration meets the definition of ASU 2014-09.

Step 2 Identify the performance obligations in the contract: A performance obligation is effectively a promise in a contract with a customer to transfer goods or services to the customer. If an entity promises to transfer more than one good or service to the customer, each performance obligation is accounted for separately if such performance obligations are distinct, as defined under ASU 2014-09.

Step 3 Determine the transaction price: The amount of consideration an entity expects to be entitled to as a result of performing services to a customer or transferring goods to a customer is the transaction price. The transaction price takes into account variable consideration, the existence of significant financing component, noncash consideration and the type of consideration payable to the entity.

Step 4 Allocate the transaction price to the performance obligations in the contract: An entity should allocate the transaction price to each performance obligation in an amount that represents the amount of the entity expects to be entitled to for satisfying each performance obligation.

Step 5 Recognize revenue when, or as, the entity satisfies a performance obligation: An entity recognizes revenue when, or as, it satisfies a performance obligation. A performance obligation can be satisfied over time or at a point in time. ASU 2014-09 provides criteria for determining the appropriate classification of each performance obligation.

Throughout 2015 and 2016, the FASB has issued a series of subsequent updates to the revenue recognition guidance in Topic 606, including ASU No. 2015-14, "*Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*" ASU No. 2016-08, "*Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations*", ASU No. 2016-10, *"Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing"*, ASU No. 2016-12, "*Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients*" and ASU No. 2016-20, "*Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers*". ASU 2014-09 and the associated amendments mentioned above will be effective for us beginning on January 1, 2018, including interim periods within that reporting period.

The standard permits the use of either the retrospective or cumulative effect transition method and early adoption is permitted. Currently, we have identified the population of contracts and formed an implementation team to determine our implementation timelines, discuss implementation challenges, technical interpretations, industry-specific treatment of certain revenue contract types, and project status. We plan to review contracts for each revenue stream identified within our business. Through this process, we will determine and document the expected changes in revenue recognition upon adoption of the revised guidance and then evaluate the potential information technology and internal control changes that will be required for adoption based on the findings from our contract review process. We will conduct our contract review process throughout 2017 and, as a result, areas of impact may be identified. We cannot reasonably quantify the impact of adoption at this time. We expect to complete our assessment of ASU 2014-09, including the transition method, in the latter half of 2017.

In August 2014, the FASB issued Accountings Standards Update 2014-15, *"Presentation of Financial Statements Going Concern (Subtopic 205-40): Disclosures of Uncertainties about an Entity's Ability to Continue as a Going Concern"* ("ASU 2014-15"). ASU 2014-15 provides guidance regarding management's responsibility to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. Certain disclosures are required should substantial doubt exist about the entities ability to continue as a going concern. This evaluation is performed each annual and interim reporting period to assess conditions or events within one year of the date that the financial statements are issued. The new standard was adopted at December 31, 2016.

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. All leases create an asset and a liability for the lessee and therefore recognition of those lease assets and lease liabilities is required by ASU 2016-02. When measuring lease assets and liabilities, payments to be made in optional extension periods should be included if the lessee is reasonably certain to exercise the option. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement.

For finance leases, we will recognize a ROU asset and liability, initially measured at the present value of the lease payments. Interest expense will be recognized on the lease liability separately from the amortization of the ROU asset. We will recognize payments of principal on the lease liability within financing activities in the consolidated statement of cash flows and payments of interest within operating activities in the consolidated statement of cash flows. For operating leases, we will recognize a ROU asset and liability, initially measured at the present value of the lease payments. We will recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis and all cash payments will be recognized in operating activities within the consolidate statement of cash flows.

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 in the initial evaluation and planning stages for ASU 2016-02 and do not expect to move beyond this stage until completion of our evaluation of ASU 2014-09, which is expected to occur in the latter half of 2017.

In March 2016, the FASB issued ASU 2016-09, "*Compensation Stock Compensation (Topic 718)*" ("ASU 2016-09"). ASU 2016-09 simplifies how certain aspects of share-based payments to employees are recorded. ASU 2016-09 requires that entities recognize the income tax effects of awards in the income statement when the awards vest or are settled, provides guidance on the classification of certain aspects of share-based payments on the statement of cash flows, changes the threshold for awards to qualify for equity classification, and allows an entity to make an accounting policy election to account for forfeitures when they occur. The new standard is effective for us beginning on January 1, 2017. As of December 31, 2016, we elected to early adopt the pronouncement.

In August 2016, the FASB issued ASU 2016-15, "*Statement of Cash Flows Classification of Certain Cash Receipts and Cash Payments"* ("ASU 2016-15"). ASU 2016-15 addresses eight specific cash flow issues with the objective of reducing existing diversity of practice. The eight specific cash flow issues contained within ASU 2016-15 are debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. ASU 2016-15 is effective for us for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. We do not believe the adoption of ASU 2016-15 will have a material impact on our cash flows.

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 6. Risk Management and Derivative Instruments" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

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. At December 31, 2016, we had no outstanding commodity derivative contracts, although we entered into various derivatives subsequent to December 31, 2016 for a portion of our expected 2017 production and first quarter 2018 production. Please see " Note 6. Risk Management and Derivative Instruments" in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K for further information.

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

Assets and liabilities recorded at fair value in the balance sheets are 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 are the derivative instruments discussed above. Our policy is to net derivative assets and liabilities where there is a legally enforceable master netting agreement with the counterparty.

Interest Rate Risk

At December 31, 2016, we had indebtedness outstanding under our Exit Facility of $128.1 million, which bears interest at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. Assuming the Exit Facility is fully drawn, a one percent increase in interest rates would result in a $1.3 million increase in annual interest cost, before capitalization.

At December 31, 2016, we did not have any interest rate derivatives in place and have not historically utilized interest rate derivatives. 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 Purchasers" for further detail about our significant customers.

Table of Contents

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.

We evaluate the credit standing of our various 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

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2016 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

Table of Contents

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 principal executive officer and principal 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, 2016.

Changes in Internal Control over Financial Reporting

There were no changes in internal control over financial reporting during the quarter ended December 31, 2016 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

PART III.

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

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

ITEM 11. EXECUTIVE COMPENSATION

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

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

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Pursuant to General Instructions G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

Table of Contents

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	First Amended Joint Chapter 11 Plan Of Reorganization of Midstates Petroleum Company, Inc. and its Debtor Affiliate, dated September 28, 2016 (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on October 4, 2016, and incorporated herein by reference).
3.1	Second Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company's Registration Statement on Form 8-A filed on October 21, 2016, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Midstates Petroleum Company, Inc. (filed as Exhibit 3.2 to the Company's Registration Statement on Form 8-A filed on October 21, 2016, and incorporated herein by reference).
4.01	Warrant Agreement, dated as of October 21, 2016 between Midstates Petroleum Company, Inc. and American Stock Transfer & Trust Company, LLC (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on October 27, 2016, and incorporated herein by reference).
4.02	Warrant Agreement, dated as of October 21, 2016, between Midstates Petroleum Company, Inc. and American Stock Transfer & Trust Company, LLC (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on October 27, 2016, and incorporated herein by reference).
10.01	Plan Support Agreement, dated as of April 30, 2016, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and the supporting parties thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 2, 2016, and incorporated herein by reference).
10.02	First Amendment to Plan Support Agreement, dated as of June 29, 2016, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and the supporting parties thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on July 6, 2016, and incorporated herein by reference).
10.03	Second Amendment to Plan Support Agreement, dated as of August 31, 2016, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and the supporting parties thereto. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 7, 2016, and incorporated herein by reference).

Table of Contents

10.04	Registration Rights Agreement, dated October 21, 2016, between Midstates Petroleum Company, Inc. and certain holders party thereto (filed as Exhibit 10.1 to the Company's Registration Statement on Form 8-A filed on October 21, 2016, and incorporated herein by reference).
10.05	Midstates Petroleum Company, Inc. 2016 Long Term Incentive Plan (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-8 filed on October 24, 2016, and incorporated herein by reference).
10.06	Senior Secured Credit Agreement, dated as of October 21, 2016, by and among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, as borrower, SunTrust Bank, as administrative agent, and certain lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 27, 2016, and incorporated herein by reference).
10.7**	Employment Agreement of Frederic F. Brace, dated October 21, 2016 (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed on October 27, 2016, and incorporated herein by reference).
10.8**	Employment Agreement of Nelson M. Haight, dated October 21, 2016 (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K filed on October 27, 2016, and incorporated herein by reference).
10.9**	Employment Agreement of Mitchell G. Elkins, dated October 21, 2016 (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K filed on October 27, 2016, and incorporated herein by reference).
10.10	Form of Midstates Petroleum Company, Inc. Director Restricted Stock Unit Agreement (Annual Grant Agreement) (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 29, 2016, and incorporated herein by reference).
10.11	Form of Midstates Petroleum Company, Inc. Director Restricted Stock Unit Agreement Pursuant to the 2016 Long Term Incentive Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on November 29, 2016, 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 Grant Thornton LLP
23.2(a)	Consent of Deloitte & Touche LLP
23.3(a)	Consent of Netherland, Sewell and Associates, Inc. Independent Petroleum Engineers
23.4(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

ITEM 16. FORM 10-K SUMMARY

None.

Table of Contents

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, 2017	/s/ FREDERIC F. BRACE
	Frederic F. Brace *President and Chief Executive Officer* *(Principal Executive Officer)*
Dated: March 30, 2017	/s/ NELSON M. HAIGHT
	Nelson M. Haight *Executive Vice President and Chief Financial Officer* *(Principal Financial Officer)*

Table of Contents

Dated: March 30, 2017

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	President and Chief Executive Officer (Principal Executive Officer)	March 30, 2017
/s/ NELSON M. HAIGHT Nelson M. Haight	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 30, 2017
/s/ RICHARD W. MCCULLOUGH Richard W. McCullough	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 30, 2017
/s/ ALAN J. CARR Alan J. Carr	Director (Chairman)	March 30, 2017
/s/ PATRICE R. DOUGLAS Patrice R. Douglas	Director	March 30, 2017
/s/ NEAL P. GOLDMAN Neal P. Goldman	Director	March 30, 2017
/s/ MICHAEL S. REDDIN Michael S. Reddin	Director	March 30, 2017
/s/ TODD R. SNYDER Todd R. Snyder	Director	March 30, 2017
/s/ BRUCE H. VINCENT Bruce H. Vincent	Director	March 30, 2017

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Midstates Petroleum Company, Inc.

We have audited the accompanying consolidated balance sheet of Midstates Petroleum Company, Inc. (a Delaware corporation) and subsidiary (the "Company") as of December 31, 2016 (Successor), and the related consolidated statements of operations, changes in stockholders' equity (deficit), and cash flows for the period from October 21, 2016 through December 31, 2016 (Successor) and the period from January 1, 2016 through October 20, 2016 (Predecessor). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Midstates Petroleum Company, Inc. and subsidiary as of December 31, 2016 (Successor) and the results of their operations and their cash flows for the period from October 21, 2016 through December 31, 2016 (Successor) and the period from January 1, 2016 through October 20, 2016 (Predecessor) in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, on September 28, 2016, the United States Bankruptcy Court for the District of Texas entered into an order confirming the petition for reorganization, which became effective on October 21, 2016. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification 852, *Reorganizations*, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods as described in Note 4.

/s/ GRANT THORNTON LLP

Kansas City, Missouri
March 30, 2017

Table of Contents

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

The accompanying 2015 and 2014 consolidated financial statements have been prepared assuming that Midstates will continue as a going concern. Midstates' event of default under the Credit Facility in 2015, a projected additional debt covenant violation, and resulting lack of liquidity as of December 31, 2015 and 2014 raised substantial doubt about its ability to continue as a going concern. The consolidated financial statements as of December 31, 2015 and for the two years in the period ended December 31, 2015 do not include any adjustments that might result from the outcome of this uncertainty.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 30, 2016

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.
CONSOLIDATED BALANCE SHEETS

(In thousands, except share amounts)

	Successor	Predecessor
	December 31, 2016	**December 31, 2015**
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 76,838	$ 81,093
Accounts receivable:		
Oil and gas sales	36,988	33,656
Joint interest billing	4,281	12,503
Other	2,456	17,506
Other current assets	3,326	1,044
Total current assets	123,889	145,802
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of full-cost accounting		
Proved properties	573,150	3,666,403
Unproved properties not being amortized	65,080	
Other property and equipment	6,339	14,798
Less accumulated depreciation, depletion, amortization and impairment	(12,974)	(3,157,332)
Net property and equipment	631,595	523,869
OTHER NONCURRENT ASSETS	5,455	9,496
TOTAL	**$ 760,939**	**$ 679,167**
LIABILITIES AND EQUITY (DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable	$ 2,521	$ 1,904
Accrued liabilities	53,731	91,712
Debt classified as current less unamortized debt issuance costs		1,890,944
Total current liabilities	56,252	1,984,560
LONG-TERM LIABILITIES:		
Asset retirement obligations	14,200	18,708
Long-term debt	128,059	
Other long-term liabilities	614	1,965
Total long-term liabilities	142,873	20,673
COMMITMENTS AND CONTINGENCIES (Note 16)		
STOCKHOLDERS' EQUITY (DEFICIT):		
Predecessor preferred stock, $0.01 par value, 49,675,000 shares authorized; no shares issued or outstanding at December 31, 2015		
Predecessor series A mandatorily convertible preferred stock, $0.01 par value, 8% cumulative dividends; no shares issued or outstanding at December 31, 2015		
Predecessor 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		110
Predecessor treasury stock		(3,081)
Predecessor additional paid-in-capital		888,247

Successor preferred stock, $0.01 par value, 50,000,000 shares authorized; no shares issued or outstanding at December 31, 2016				
Successor warrants, 6,625,554 warrants outstanding at December 31, 2016		37,329		
Successor common stock, $0.01 par value, 250,000,000 shares authorized; 24,994,867 shares issued and 24,994,867 shares outstanding at December 31, 2016		250		
Successor treasury stock				
Successor additional paid-in-capital		514,305		
Retained earnings (deficit)		9,930		(2,211,342)
Total stockholders' equity (deficit)		561,814		(1,326,066)
TOTAL	**$**	**760,939**	**$**	**679,167**

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

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Successor	Predecessor		
	Period October 21, 2016 through December 31, 2016	Period January 1, 2016 through October 20, 2016	For the Years Ended December 31, 2015	2014
REVENUES:				
Oil sales	$ 25,549	$ 112,628	$ 217,636	$ 466,655
Natural gas liquid sales	8,391	27,473	38,249	87,771
Natural gas sales	13,635	48,318	66,823	99,204
Gains on commodity derivative contracts net			40,960	139,189
Other	950	4,809	1,477	1,364
Total revenues	48,525	193,228	365,145	794,183
EXPENSES:				
Lease operating and workover	15,324	52,803	81,473	79,598
Gathering and transportation	3,194	14,362	15,546	13,404
Severance and other taxes	1,286	5,210	8,605	24,266
Asset retirement accretion	210	1,414	1,610	1,706
Depreciation, depletion, and amortization	12,974	62,302	198,643	269,935
Impairment in carrying value of oil and gas properties		232,108	1,625,776	86,471
General and administrative	4,864	22,362	38,703	48,733
Acquisition and transaction costs			330	4,129
Debt restructuring costs and advisory fees		7,590	36,141	
Other			2,121	5,108
Total expenses	37,852	398,151	2,008,948	533,350
OPERATING INCOME (LOSS)	10,673	(204,923)	(1,643,803)	260,833
OTHER INCOME (EXPENSE):				
Interest income		81	115	39
Interest expense net of amounts capitalized (Predecessor Period excludes interest expense of $89.5 million on senior and secured notes)	(743)	(66,360)	(163,148)	(137,548)
Reorganization items, net (Note 3)		1,594,281		
Total other income (expense)	(743)	1,528,002	(163,033)	(137,509)
INCOME (LOSS) BEFORE TAXES	9,930	1,323,079	(1,806,836)	123,324
Income tax (expense) benefit			9,641	(6,395)
NET INCOME (LOSS)	**$ 9,930**	**$ 1,323,079**	**$ (1,797,195)**	**$ 116,929**
Predecessor preferred stock dividend			(948)	(10,378)
Predecessor participating securities Series A Preferred Stock				(35,696)
Predecessor participating securities non-vested restricted stock		(16,522)		(3,584)
Successor participating securities non-vested restricted stock	(280)			

NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS	**$**	**9,650**	**$**	**1,306,557**	**$**	**(1,798,143)**	**$**	**67,271**
Basic and diluted net income (loss) per share attributable to common shareholders	$	0.39	$	122.74	$	(232.74)	$	10.13
Basic and diluted weighted average number of common shares outstanding (Note 14)		25,009		10,645		7,726		6,644

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

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY (DEFICIT)
(See Notes 11 and 12 for share history)

(In thousands)

	Series A Preferred Stock	Common Stock	Warrants	Treasury Stock	Additional Paid-in-Capital	Retained Earnings (Deficit)	Total Stockholders' Equity (Deficit)
Balance as of December 31, 2013 (Predecessor)	**$ 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 (Predecessor)	**$ 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 (Predecessor)	**$**	**$ 110**	**$**	**$ (3,081)**	**$ 888,247**	**$ (2,211,342)**	**$ (1,326,066)**
Share-based compensation		(6)			3,045		3,039
Acquisition of treasury stock				(53)			(53)
Net income						1,323,079	1,323,079
Balance as of October 21, 2016 (Predecessor)	**$**	**$ 104**	**$**	**$ (3,134)**	**$ 891,292**	**$ (888,263)**	**$ (1)**
Cancellation of predecessor equity		(104)		3,134	(891,292)	888,263	1
Balance as of October 21, 2016 (Predecessor)	**$**	**$**	**$**	**$**	**$**	**$**	**$**
Issuance of successor common stock		247			510,905		511,152
Issuance of successor warrants			37,329				37,329
Balance as of October 21, 2016 (Successor)	**$**	**$ 247**	**$ 37,329**	**$**	**$ 510,905**	**$**	**$ 548,481**
Issuance of successor common stock		3					3
Share-based compensation					3,400		3,400
Net income						9,930	9,930
Balance as of December 31, 2016 (Successor)	**$**	**$ 250**	**$ 37,329**	**$**	**$ 514,305**	**$ 9,930**	**$ 561,814**

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

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Successor	Predecessor		
			Years Ended December 31,	
	Period October 21, 2016 through December 31, 2016	Period January 1, 2016 through October 20, 2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income (loss)	$ 9,930	$ 1,323,079	$ (1,797,195)	$ 116,929
Adjustments to reconcile net income/(loss) to net cash provided by operating activities:				
(Gains) losses on commodity derivative contracts net			(40,960)	(139,189)
Net cash received (paid) for commodity derivative contracts not designated as hedging instruments			167,669	(18,332)
Asset retirement accretion	210	1,414	1,610	1,706
Depreciation, depletion, and amortization	12,974	62,302	198,643	269,935
Impairment in carrying value of oil and gas properties		232,108	1,625,776	86,471
Share-based compensation, net of amounts capitalized to oil and gas properties	2,909	2,564	4,408	8,618
Deferred income taxes			(9,641)	5,586
Amortization of deferred financing costs	63	4,587	11,316	7,857
Paid-in-kind interest expense		3,531	6,415	
Amortization of deferred gain on debt restructuring		(8,246)	(14,948)	
Operating lease abandonment		1,574		
Non-cash reorganization items		(1,630,873)		
Transaction costs for debt restructuring			34,398	
Change in operating assets and liabilities:				
Accounts receivable oil and gas sales	(115)	(2,391)	26,437	33,322
Accounts receivable JIB and other	(1,812)	22,002	22,833	(18,897)
Other current and noncurrent assets	1,783	(5,868)	590	3,191
Accounts payable	(1,555)	1,797	(4,176)	2,327
Accrued liabilities	(740)	55,160	(20,887)	(7,733)
Other	(3)	(743)	1,095	(247)
Net cash provided by operating activities	**$ 23,644**	**$ 61,997**	**$ 213,383**	**$ 351,544**
CASH FLOWS FROM INVESTING ACTIVITIES:				
Investment in property and equipment	$ (23,346)	$ (133,307)	$ (336,922)	$ (556,397)
Proceeds from the sale of oil and gas properties			42,366	152,133
Net cash used in investing activities	**$ (23,346)**	**$ (133,307)**	**$ (294,556)**	**$ (404,264)**