Midstates Petroleum Company, Inc.
Form 10-K
March 14, 2018
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2017

OR

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

For the transition period from to .

Commission File Number: 001-35512

MIDSTATES PETROLEUM COMPANY, INC.

(Exact name of registrant as specified in its charter)

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

Registrant s telephone number, including area code: **(918) 947-8550**

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

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

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

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

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 x

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 x 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 x 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 x

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

The aggregate market value of the registrant s Common Stock held by non-affiliates of the registrant was approximately $146.8 million based upon the closing price of such stock on June 30, 2017, the last business day of the registrant s most recently completed second fiscal quarter, of $12.67 per share.

The number of shares outstanding of our stock at March 8, 2018 is shown below:

Class	Number of shares outstanding
Common stock, $0.01 par value	25,153,381

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Midstates Petroleum Company, Inc. for the Annual Meeting of Shareholders to be held in June 2018, which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements other than statements of historical fact included in this annual report are forward-looking statements, including, without limitation, statements regarding our strategy, future operations, financial position, estimated revenues and 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;
- 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;
- 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.

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These factors include:

- variations in the market demand for, and prices of, oil, natural gas liquids (NGLs) 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.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

Boe/day: Barrels of oil equivalent per day.

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

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

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

MMBoe: One million barrels of oil equivalent.

MMBtu: One million British thermal units.

Net acres: The percentage of total acres an owner has out of a particular number of acres, or a specified tract.

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 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.

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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.

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 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 . Our common stock began trading on the NYSE under the symbol MPO beginning on May 4, 2017. 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, 2017, we had 129 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.

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 will disclose any amendments or waivers to our Code of Ethics on our website.

Business Strategy

Our goal is to grow shareholder value through optimized capital investments and generation of free cash flow. To achieve these objectives, we strive to:

- Operate in a safe and environmentally responsible manner;
- Maximize our return on capital deployed by utilizing our extensive technical and operating experience in our core areas of operations to focus on identifying opportunities to achieve the best rate of return and the highest probability of success;
- Maintain a best in class cost structure to maximize the cash flow margin of our production;
- Prioritize free cash flow generation over production growth. Strive towards the optimum balance between free cash flow generation and sustaining inventory for future investment. We will optimize free cash flow generation by focused capital investments, optimizing our base production, and maintaining a low-cost structure; and
- Maintain maximum optionality by maintaining low net debt, balancing shareholder cash returns with replenishing inventory, and evaluating strategic alternatives within and outside of our current asset base.

Our balance sheet and strong liquidity position provide us with significant resources to develop our multi-year drilling inventory and judiciously expand our core acreage positions. For 2018, we intend to opportunistically achieve the best return on investments by optimizing our drilling and completion design, focusing on minimizing well down time and optimizing well productivities while maintaining both capital discipline and a low-cost structure.

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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 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. Further information is set forth in 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.

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.

Summary of Oil and Gas Properties and Operations

Mississippian Lime

Our Mississippian Lime assets are located in Oklahoma and target the Mississippian Lime formation. At December 31, 2017, our acreage consisted of approximately 97,762 net (117,451 gross) prospective acres in the Mississippian Lime trend in Woods and Alfalfa Counties of Oklahoma, which we currently intend to develop using horizontal wells.

Our properties in this area represented 92% of our total proved reserves as of December 31, 2017. As of December 31, 2017, we held an average working interest and average net revenue interest of 77% and 62%, respectively, in this area.

For the year ended December 31, 2017, the Successor Period and the Predecessor Period, our average daily production from our Mississippian Lime assets was as follows:

	Successor		Predecessor
	Year Ended December 31, 2017	**Period October 21, 2016 through December 31, 2016**	**Period January 1, 2016 through October 20, 2016**
Oil (Bbls)	5,108	6,048	8,156
Natural gas liquids (Bbls)	4,273	4,843	5,326
Natural gas (Mcf)	52,797	58,816	68,107
Net Boe/day	**18,181**	**20,694**	**24,833**

At December 31, 2017, we had one operated drilling rig in operation in the Mississippian Lime horizontal well program. For 2018, we anticipate investing between $100.0 million and $120.0 million in the area.

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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, 2017, our acreage consisted of approximately 76,409 net (92,289 gross) acres in Texas and 16,198 net (41,332 gross) acres in western Oklahoma.

Our properties in this area represented 8% of our total proved reserves as of December 31, 2017. As of December 31, 2017, we held an average working interest and average net revenue interest of 64% and 50%, respectively, in this area.

For the year end December 31, 2017, Successor Period and Predecessor Period, our average daily production from the Anadarko Basin area was as follows:

	Successor		Predecessor
	Year Ended December 31, 2017	**Period October 21, 2016 through December 31, 2016**	**Period January 1, 2016 through October 20, 2016**
Oil (Bbls)	1,379	1,508	1,927
Natural gas liquids (Bbls)	1,066	1,118	1,247
Natural gas (Mcf)	9,135	9,903	10,856
Net Boe/day	**3,967**	**4,277**	**4,983**

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 Gulf Coast (or Louisiana) as of December 31, 2017, 2016 or 2015.

During the three months ended September 30, 2017, we closed on the sale of our oil and gas properties in Lincoln County, Oklahoma, which had approximately 12,894 net (19,888 gross) acres for $7.0 million in cash ($2.9 million, net after assumption of liabilities), subject to standard post-closing adjustments.

Reserves Information

Estimated Proved Reserves

The following table sets forth our estimated net proved reserves by product and type using SEC pricing:

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)	PV-10 (1) (in thousands)
Mississippian Lime:					
Proved developed producing	12,606	148,052	11,359	48,640	333,398
Proved developed non-producing	1,822	21,605	1,680	7,103	40,191
Proved undeveloped	13,866	125,169	9,729	44,457	131,360
Anadarko Basin:					
Proved developed producing	2,840	20,893	2,425	8,747	53,184
Proved developed non-producing					
Proved undeveloped					
Total:					
Proved developed producing	15,446	168,945	13,784	57,387	386,582
Proved developed non-producing	1,822	21,605	1,680	7,103	40,191
Proved undeveloped	13,866	125,169	9,729	44,457	131,360
Total Proved at December 31, 2017	31,134	315,719	25,193	108,947	558,133

(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

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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, 2017	As of December 31, 2016
PV-10	$ 558,133	$ 578,155
Present value of future income tax, discounted at 10%	(8,890)	(48,205)
Standardized measure of discounted future net cash flows	**$ 549,243**	**$ 529,950**

Proved Undeveloped Reserves

The following table summarizes the changes in our estimated proved undeveloped reserves during the year ended December 31, 2017 (in MBoe):

Proved undeveloped reserves, December 31, 2016	**107,366**
Purchases of reserves in place	
Sales of reserves	
Extensions and discoveries	13,663
Revisions of previous estimates	(74,842)
Conversion to proved developed reserves	(1,730)
Proved undeveloped reserves, December 31, 2017	**44,457**

No less than annually, we review our five-year development schedule. This review encompasses many factors, including current year drilling results, forward pricing curve, 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. On November 1, 2017, David Sambrooks was appointed President and Chief Executive Officer of the Company. Upon David s appointment, we began a strategic review of all areas of operations. This review was completed during the fourth quarter of 2017 and our strategy was refined to add further focus to optimizing free cash flows and keeping leverage to a minimum. As a result, in December of 2017 we decreased our current drilling activity from two drilling rigs to one drilling rig. Further, the five-year development plan was revised from a two-rig program to a one rig program. This change in strategy (reduced 5-year drilling activity) led to a reduction in our undeveloped proved inventory under SEC guidelines from 274 locations at year end 2016 to 139 locations at year end 2017. In addition, at year end 2017 our proved undeveloped type curve was revised downward by our third-party reserves engineering firm and capital costs assumptions were revised upward, both as a result of recent drilling results. The revised type curve still generates attractive capital returns of 30.6% IRR at year-end 2017 SEC pricing, and 39.1% IRR at December 31, 2017 strip pricing. As a result of our focus on optimizing free cash flow, keeping leverage to a minimum and optimizing drilling returns, all proved undeveloped reserves included in the December 31, 2017 reserve report are focused on infill drilling in the Carmen and Dacoma areas. All undeveloped locations not able to be drilled utilizing our anticipated five-year development schedule were excluded from the December 31, 2017 reserve report but continue to meet the definition of a proved undeveloped location from an engineering standpoint.

Independent Petroleum Engineers

For our Mississippian Lime and Anadarko Basin assets, our estimated reserves and related future net revenues at December 31, 2017, 2016 and 2015 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.

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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 30 years of practical experience in petroleum engineering, with over 28 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Technology Used to Establish Proved Reserves

Under Rule 4-10(a)(22) of Regulation S-X, as promulgated by the SEC, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term reasonable certainty implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that 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 employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data.

Internal Controls Over Reserves Estimation Process

We maintain an internal staff of petroleum engineers, land and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to CGA 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. Each quarter, estimated proved oil and gas reserves are presented to a committee of executives and key management for review and approval and annually, our development plan for proved undeveloped reserves are reviewed and approved by our executives.

At December 31, 2017, 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 17 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.

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Production, Revenues and Price History

Oil, NGLs and natural gas are commodities. The price that we receive for the oil, NGLs and natural gas we produce is largely a function of market supply and demand. 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 year ended December 31, 2017, the Successor Period, the Predecessor Period and the year ended December 31, 2015. For additional details, see information set forth in Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Successor		Predecessor	
	Year Ended December 31, 2017	Period October 21, 2016 through December 31, 2016	Period January 1, 2016 through October 20, 2016	Year Ended December 31, 2015
Operating Data:				
Net production volumes:				
Oil (MBbls)	2,368	544	2,964	4,794
NGLs (MBbls)	1,949	429	1,932	2,473
Natural gas (MMcf)	22,606	4,948	23,215	28,403
Total oil equivalents (MBoe)	8,084	1,798	8,765	12,001
Average daily production (Boe/d)	22,148	24,971	29,816	32,880
Average Sales Prices:				
Oil, without realized derivatives (per Bbl)	$ 49.45	$ 46.96	$ 37.99	$ 45.40
Oil, with realized derivatives (per Bbl)	$ 50.92	$ 46.96	$ 37.99	$ 74.74
Natural gas liquids, without realized derivatives (per Bbl)	$ 22.64	$ 19.55	$ 14.22	$ 15.46
Natural gas liquids, with realized derivatives (per Bbl)	$ 22.64	$ 19.55	$ 14.22	$ 15.46
Natural gas, without realized derivatives (per Mcf)	$ 2.64	$ 2.76	$ 2.08	$ 2.35
Natural gas, with realized derivatives (per Mcf)	$ 2.79	$ 2.76	$ 2.08	$ 3.30
Costs and Expenses (per Boe of production):				
Lease operating and workover	$ 7.83	$ 8.52	$ 6.02	$ 6.79
Gathering and transportation	$ 1.79	$ 1.78	$ 1.64	$ 1.30
Severance and other taxes	$ 1.10	$ 0.72	$ 0.59	$ 0.72
Asset retirement accretion	$ 0.14	$ 0.12	$ 0.16	$ 0.13
Depreciation, depletion and amortization	$ 8.14	$ 7.22	$ 7.11	$ 16.55
Impairment of oil and gas properties	$ 15.50	$	$ 26.48	$ 135.47
General and administrative	$ 3.63	$ 2.71	$ 2.55	$ 3.22
Acquisition and transaction costs	$	$	$	$ 0.03
Debt restructuring costs and advisory fees	$	$	$ 0.87	$ 3.01
Other	$	$	$	$ 0.18

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The following table sets forth information regarding oil, NGLs and natural gas daily production for each of the fields that represented more than 15% of our estimated total proved reserves for the year ended December 31, 2017, the Successor Period, the Predecessor Period and the year ended December 31, 2015:

	Successor		Predecessor	
	Year Ended December 31, 2017	Period October 21, 2016 through December 31, 2016	Period January 1, 2016 through October 20, 2016	Year Ended December 31, 2015
Mississippian(1)				
Daily production volumes:				
Oil (Bbls)	5,108	6,035	8,147	10,187
NGLs (Bbls)	4,273	4,464	4,968	4,900
Natural gas (Mcf)	52,797	56,740	65,737	62,514
Total oil equivalents (Net Boe/day)	**18,181**	**19,956**	**24,071**	**25,506**
Anadarko				
Daily production volumes:				
Oil (Bbls)	1,379	1,508	1,927	2,680
NGLs (Bbls)	1,066	1,118	1,247	1,388
Natural gas (Mcf)	9,135	9,903	10,856	12,921
Total oil equivalents (Net Boe/day)	**3,967**	**4,277**	**4,983**	**6,222**

(1) These volumes represent only Mississippian Lime production and do not include Hunton production volumes. We divested our Hunton producing properties in Lincoln County during the year ended December 31, 2017. Further information is set forth in Summary of Oil and Gas Properties and Operations above and Note 7. Property and Equipment in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K.

Productive Wells

The following table presents our total gross and net productive wells as of December 31, 2017:

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Total productive wells	779	550	64	46	843	596

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, 2017 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	72,579	56,166	44,872	41,596	117,451	97,762
Anadarko Basin	56,640	36,242	76,981	56,365	133,621	92,607
Total	129,219	92,408	121,853	97,961	251,072	190,369

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Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2017 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 2018		Expiring 2019		Expiring 2020	
	Gross	Net	Gross	Net	Gross	Net
Mississippian Lime	4,441	3,200	1,478	823	4,462	3,139
Anadarko Basin	1,720	611	8,709	1,397	8,252	1,435
Total Undeveloped Acreage Expirations	6,161	3,811	10,187	2,220	12,714	4,574

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, we may allow leasehold rights on acreage not held by production to expire in this area, 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 year ended December 31, 2017, the Successor Period, the Predecessor Period and the year ended December 31, 2015. 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			
	Year Ended December 31, 2017		Period October 21, 2016 through December 31, 2016		Period January 1, 2016 through October 20, 2016		Year Ended December 31, 2015	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development wells:								
Productive	26	25	3	3	40	38	84	74
Dry holes								
Total	**26**	**25**	**3**	**3**	**40**	**38**	**84**	**74**
Exploratory wells:								
Productive								
Dry holes							3	
Total							3	
Total wells	**26**	**25**	**3**	**3**	**40**	**38**	**87**	**74**

As of December 31, 2017, there were 9 gross (and 9 net) development wells awaiting completion; one development well was being drilled and no exploratory wells were being drilled.

As of December 31, 2017, we had one drilling rig in operation. Our recent drilling activity has primarily focused on the development 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 year ended December 31, 2017, three purchasers accounted for 37%, 25% and 14%, respectively, of the Company s revenue. 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. 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.

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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 $0.12 to $0.15 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, NGLs and natural gas. 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.

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.

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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.

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, NGLs and natural gas 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.

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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 and subsequently filed an action for a declaratory judgment on May 4, 2016. In December 2016, the U.S. District Court for the District of Columbia approved a consent decree between the EPA and these groups, which requires the EPA to review and issue a notice of proposed rulemaking to revise the E&P waste exemption or a determination that revision is not necessary. 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.

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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, in May 2016, the EPA 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 (the 2016 NSPS Rules). In May 2017, the EPA announced a 90-day stay of portions of the 2016 NSPS Rules, which stay was vacated in part by the U.S. Court of Appeals for the D.C. Circuit on July 3, 2017. The EPA also proposed a two year stay of portions of the 2016 NSPS Rules on June 12, 2017, for which the public notice and comment period closed on August 9, 2017. 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. However, the Department of the Interior (the parent department of BLM) announced in October 2017 that it would delay the effectiveness of certain aspects of the BLM methane rules intended to go into effect in January 2018. 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 was one of almost 200 nations that is party to the Paris Agreement adopted in

December 2015 to reduce global GHG emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement and that it would potentially seek to renegotiate the Paris Agreement on more favorable terms. Although President Trump has the authority to unilaterally withdraw the United States from the Paris Agreement, per the terms of the Paris Agreement, such a withdrawal may not be made until three years from the effective date of the Paris Agreement, which is November 4, 2019, and any such withdrawal only becomes effective one year after the notice of withdrawal is provided. Despite the planned withdrawal of the United States, various state and local governments have publicly committed to continue to further the goals of the Paris 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. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change

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could reduce demand for oil, NGLs and natural gas. 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 (SDWA) 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 continues to be a 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.

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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. On March 1, 2017, the OGCD also issued a statement saying that further actions to reduce the earthquake rate in Oklahoma could be expected. While our current plans are for future disposal wells to inject into formations other than the Arbuckle and we currently operate 11 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 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. 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. The U.S. District Court of Wyoming struck down this rule in June 2016, but the decision was appealed to the U.S. Tenth Circuit Court of Appeals. Although the Trump Administration has indicated it would like to repeal this rule, the Tenth Circuit dismissed this appeal and the underlying case on September 21, 2017 and it is unclear whether the rule remains in effect. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

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 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 governments may also 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.

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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.

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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

Oil, NGLs and natural gas prices are volatile. A sustained decline in oil, NGLs and natural gas prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and, to a lesser extent, NGLs and natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. Oil, NGLs and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for these commodities have been volatile, and are likely to continue to be volatile in the future, especially given current economic and geopolitical conditions.

The 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, NGLs 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. Lower oil, NGLs and natural gas prices have in the past adversely affected our cash flows, borrowing ability and present value of our reserves. It may also reduce the amount of oil, NGLs and natural gas that we can produce economically. Any sustained periods of low prices for oil, NGLs 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.

There are no assurances that we will be able to successfully implement our business plan or successfully operate as a restructured business.

Following emergence from the Chapter 11 Cases in 2016, we significantly restructured our business and adopted a new business plan. The restructured Company and new business plan have been in effect for a limited period of time and there are no assurances that we will be able to successfully implement our business plan or successfully operate as a restructured business. Additionally, we cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations in the future.

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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;
- 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
- 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 below. 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.

We may be subject to risks in connection with divestitures and acquisitions.

In November 2017, we announced that the Company had engaged SunTrust Robinson Humphrey to explore and evaluate potential strategic alternatives for our Anadarko Basin and NW STACK assets. We may sell off any of these core or non-core assets in order to increase capital resources available for other core assets, create organizational and operational efficiencies or for other purposes. Various factors could materially affect our ability to dispose of such assets, including the approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the assets with terms we deem acceptable. Though we continue to evaluate various options for the divestiture of such assets, there can be no assurance that this evaluation will result in any specific action.

In addition, in the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. As a result, our acquisition activities may not be successful, which may hinder our replacement of reserves and adversely affect our results of operations.

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. On May 24, 2017, the Company entered into the First Amendment to the Exit Facility (the First Amendment). The First Amendment, among other things, moved the first scheduled borrowing base redetermination from April 2018 to October 2017. On October 27, 2017, the Company s borrowing base was redetermined at the existing amount of $170.0 million. The Company s Anadarko Basin assets in Texas and Oklahoma were excluded from the redetermination of the borrowing base. Any potential future 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.

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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, 2017, 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, NGLs 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.

The Exit Facility, as amended, includes certain financial maintenance covenants that are required to be calculated on a quarterly basis for compliance purposes. These financial maintenance covenants include EBITDA to interest expense for the trailing four fiscal quarters of not less than 2.50:1.00 and a limitation of Total Net Indebtedness (as defined in the Exit Facility) to EBITDA for the trailing four fiscal quarters of not more than 4.00:1.00.

In addition, the Exit Facility contains various other covenants that, among other things, may restrict our ability to: (i) incur additional indebtedness or guarantee indebtedness (ii) make loans and investments; (iii) pay dividends on capital stock and make other restricted payments, including the prepayment or redemption of other indebtedness; (iv) create or incur certain liens; (v) sell, transfer or otherwise dispose of certain assets; (vi) enter into certain types of transactions with our affiliates; (vii) acquire, consolidate or merge with another entity upon certain terms and conditions; (viii) sell all or substantially all of our assets; (ix) prepay, redeem or repurchase certain debt; (x) alter the business we conduct and make amendments to our organizational documents, (xi) enter into certain derivative transactions and (xii) enter into certain marketing agreements and take-or-pay arrangements.

As of December 31, 2017, 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.

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

On the Effective Date we adopted fresh start accounting and 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 are not 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 are not 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;
- 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 could experience drought conditions which would diminish 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, 2017, 2016 and 2015, 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.

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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.

If oil and natural gas prices decrease in the future, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

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

Oil, NGLs 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, NGLs and natural gas production to reduce our exposure to fluctuations in the price of oil, NGLs and natural gas. At December 31, 2017, we had outstanding commodity derivative contracts that extend through December 2019. Although hedged through December 2019, a portion of our 2018 and 2019 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 continually reevaluate and consider whether in the long-term we will hedge any of our future production. See Management s Discussion and Analysis of Financial Condition and 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 a summary of our commodity derivative positions.

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, NGLs and natural gas, we currently and have historically chosen to enter into derivative instruments at times for a portion of our oil, NGLs 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.

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We incurred losses from operations during the current year as well as certain periods historically and may continue to do so in the future.

We incurred net losses of $85.1 million and $1.8 billion for the years ended December 31, 2017 and 2015, respectively. 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.

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, 2017, 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 sufficient period of time. 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.

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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.

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 in Business Regulation of the Oil and Natural Gas Industry Water Discharges and Fluid Injections , 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 fractionation 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.

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

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

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

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Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, or increases in interest rates. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to drill our identified locations and pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. 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, NGLs 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.

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. Although these provisions were largely unchanged in the Tax Cuts and Jobs Act of 2017, which was signed in December 2017, Congress could consider, and could include, some, or all of these proposals as part of future tax reform legislation, to accompany lower federal income tax rates. It is unclear when or if any of the foregoing or similar proposals will be considered and enacted as part of future tax reform legislation and, if enacted, how soon any such changes can become effective. The passage of any 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.

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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.

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.

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Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general in addition to our own results of operations, competitive position or financial condition. For example, in May 2016, the EPA 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 (the 2016 NSPS Rules). In May 2017, the EPA announced a 90-day stay of portions of the 2016 NSPS Rules, which stay was vacated in part by the U.S. Court of Appeals for the D.C. Circuit on July 3, 2017. The EPA also proposed a two year stay of portions of the 2016 NSPS Rules on June 12, 2017, for which the public notice and comment period closed on August 9, 2017. 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 preconstruction 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 BLM issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on public lands. However, the Department of the Interior (the parent department of BLM) announced in October 2017 that it would delay the effectiveness of certain aspects of the BLM methane rules intended to go into effect in January 2018.

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 was one of almost 200 nations that is party to the Paris Agreement adopted in December 2015 to reduce global GHG emissions. On June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement and that it would potentially seek to renegotiate the Agreement on more favorable terms. Although President Trump has the authority to unilaterally withdraw the United States from the Paris Agreement, per the terms of the Agreement, such a withdrawal may not be made until three years from the effective date of the Agreement, which is November 4, 2019, and any such withdrawal only becomes effective one year after the notice of withdrawal is provided. Despite the planned withdrawal of the United States, various state and local governments have publicly committed to continue to further the goals of the Paris 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. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for oil, NGLs and natural gas. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely utilize hydraulic fracturing techniques in many of our oil and natural gas drilling and completion programs. The process is typically regulated by state oil and natural gas commissions or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has 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 under the CRA. 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. The U.S. District Court of Wyoming struck down this rule in June 2016, but the decision was appealed to the U.S. Tenth Circuit Court of Appeals. Although the Trump Administration has indicated it would like to repeal this rule, the Tenth Circuit dismissed this appeal and the underlying case on September 21, 2017 and it is unclear whether the rule remains in effect. 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 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 SDWA or otherwise.

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

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

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

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.

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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.

Our business could be adversely affected by security threats, including cyber-security threats, and related disruptions.

We rely heavily on our information systems, and the availability and integrity of these systems are essential for us to conduct our business and operations. As a producer of oil, NGLs and natural gas, we face various security threats, including cyber-security threats, to gain unauthorized access to our sensitive information or to render our information or systems unusable, and threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing and other facilities, refineries and pipelines. The potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our implementation of various procedures and controls to monitor and mitigate such security threats and to increase security for our information, systems, facilities and infrastructure may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of, or damage to, sensitive information or facilities, infrastructure and systems essential to our business and operations, as well as data corruption, communication interruptions or other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position, results of operations and cash flows.

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.

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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;
- business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as fluctuations in the prices of oil, NGLs and natural gas and general economic and market conditions.
- additions or departures of key members of management;
- any increased indebtedness we may incur in the future;
- announcements by us or our competitors of significant contracts, acquisitions, dispositions, strategic partnerships, joint ventures or capital commitments; and
- changes or proposed changes in laws or regulations affecting the oil and gas industry or enforcement of these laws and regulations, or announcements relating to these matters.

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, 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.

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, 2017, we had outstanding approximately 25,173,346 shares of common stock and warrants to purchase an aggregate of 6,625,554 shares of our common stock. We have also reserved an additional 3,513,950 units for granting under the 2016 LTIP of which 2,129,011 units remain available at December 31, 2017. 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, 2017, funds advised by Avenue Capital Group, Centerbridge Partners and Fir Tree Partners held approximately 13.9%, 9.8% and 25.4%, 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.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

As of December 31, 2017, 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.

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PART II.

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

Market for Registrant s Common Equity

Prior to October 24, 2016, our common stock traded on the OTC Pink market under the symbol MPOY . On October 24, 2016, our new common stock began trading on the NYSE MKT under the symbol MPO . On May 4, 2017, our common stock began trading on the NYSE under the symbol MPO . The following table sets forth the quarterly high and low sales prices per share as reported by the NYSE and NYSE MKT during 2017 and 2016:

	Price Range			
	High		Low	
Quarter Ended 2017:				
December 31, 2017	$	17.55	$	14.04
September 30, 2017	$	16.94	$	12.42
June 30, 2017	$	19.75	$	10.87
March 31, 2017	$	22.54	$	17.64
Quarter Ended 2016:				
December 31, 2016 (from October 24)	$	25.00	$	17.01

On March 8, 2018, the last sales price of our common stock, as reported on the NYSE, was $13.56 per share.

As of March 8, 2018, there were 25,153,381 shares of common stock outstanding.

Holders

The number of shareholders of record of our common stock was thirteen on March 8, 2018.

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 currently anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Equity Compensation Plan Information

Information regarding securities authorized for issuance under our equity compensation plan is set forth in our definitive proxy statement for our 2017 Annual Meeting of Stockholders, which is incorporated by reference here.

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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 through December 31, 2017, 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.

Issuer Purchases of Equity Securities

The following table provides information regarding the purchase of our common stock made during the fourth quarter of 2017. Shares purchased represent the net settlement on vesting of restricted stock necessary to satisfy the minimum statutory withholding requirements.

Period	Total Number of Shares Purchased	Average Price Paid Per Share
October 1, 2017 October 31, 2017	65,869	$ 14.75
November 1, 2017 November 30, 2017	345	$ 15.95
December 1, 2017 December 31, 2017		$
Total	66,214	$ 14.76

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ITEM 6. SELECTED FINANCIAL DATA

The following tables set forth our selected financial data over the five-year period ended December 31, 2017. 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 year ended December 31, 2017, the Successor Period, the Predecessor Period and the year ended 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 financial data for the years ended December 31, 2014 and 2013 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)	**December 31, 2017**	**For the Period October 21, 2016 through December 31, 2016**	**For the Period January 1, 2016 through October 20, 2016**	**2015(1)**	**December 31, 2014(2)**	**2013(3)**
Income Statement Data						
Total revenues	$ 228,753	$ 48,525	$ 193,228	$ 365,145	$ 794,183	$ 469,506
Net income (loss)	(85,077)	9,930	1,323,079	(1,797,195)	116,929	(343,985)
Net income (loss) attributable to common shareholders(4)	(85,077)	9,650	1,306,557	(1,798,143)	67,271	(359,574)
Net income (loss) per share attributable to common shareholders						
Basic and diluted	$ (3.39)	$ 0.39	$ 122.74	$ (232.74)	$ 10.13	$ (54.68)
Other Financial Data						
Net cash provided by operating activities	$ 119,602	$ 23,644	$ 61,997	$ 213,383	$ 351,544	$ 237,588
Net cash used in investing activities	(125,964)	(23,346)	(133,307)	(294,556)	(404,264)	(1,204,332)
Net cash (used in) provided by financing activities	(1,978)		66,757	150,709	31,114	981,029
Adjusted EBITDA(5)	125,166	26,766	93,465	315,340	474,098	330,759

(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 Disposition), which

closed on May 1, 2014.

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

(4) The years ended December 31, 2015, 2014 and 2013 include the effect of an undeclared Series A Preferred Stock dividend of $0.9 million, $10.4 million and $15.6 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.

(5) 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.

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Presented below is our historical financial data as of the dates indicated. The historical balance sheet data as of December 31, 2017 and December 31, 2016 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, 2015, 2014 and 2013 are derived from our audited financial statements not included in this Annual Report on Form 10-K.

	Successor		Predecessor		
(in thousands, except per share amounts)	**December 31, 2017**	**December 31, 2016**	**2015(1)**	**December 31, 2014(2)**	**2013(3)**
Balance Sheet Data					
Cash and cash equivalents	$ 68,498	$ 76,838	$ 81,093	$ 11,557	$ 33,163
Net property and equipment	574,462	631,595	523,869	2,123,116	2,094,894
Total assets	688,128	760,939	679,167	2,447,175	2,308,637
Total debt, including debt classified as current (4)	128,059	128,059	1,890,944	1,706,532	1,667,680
Stockholders equity (deficit)	485,587	561,814	(1,326,066)	465,862	339,999
Weighted average number of common shares outstanding	25,119	25,009	7,726	6,644	6,576

(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.

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

(4) 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.

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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.

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			
	December 31, 2017	For the Period October 21, 2016 Through December 31, 2016	For the Period January 1, 2016 Through October 20, 2016	2015	December 31, 2014	2013
Adjusted EBITDA reconciliation to net income (loss):						
Net income (loss)	$ (85,077)	$ 9,930	$ 1,323,079	$ (1,797,195)	$ 116,929	$ (343,985)
Depreciation, depletion and amortization	65,832	12,974	62,302	198,643	269,935	250,396
Impairment in carrying value of oil and gas properties	125,300		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	(3,659)			(40,960)	(139,189)	44,284
Net cash received (paid) for commodity	6,891			167,669	(18,332)	(17,585)

derivative contracts not designated as hedging instruments											
Reorganization items, net						(1,594,281)					
Income tax expense (benefit)								(9,641)		6,395		(146,529)
Interest income		(9)				(81)		(115)		(39)		(33)
Interest expense net of amounts capitalized (Predecessor Period excludes interest expense of $89.5 million on senior and secured notes)		5,592		743		66,360		163,148		137,548		83,138
Asset retirement obligation accretion		1,100		210		1,414		1,610		1,706		1,435
Share-based compensation, net of amounts capitalized		9,196		2,909		2,564		4,408		8,618		5,713
Adjusted EBITDA	**$**	**125,166**	**$**	**26,766**	**$**	**93,465**	**$**	**315,340**	**$**	**474,098**	**$**	**330,759**

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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.

As of December 31, 2017, our properties consisted of approximately 190,400 net acres of leasehold, with 843 gross productive wells, 71% of which we operate, and in which we held an average working interest of approximately 86%. As of December 31, 2017, our estimated net proved reserves were 108,947 MMBoe, of which 52% was oil or NGLs and 59% was proved developed. During the year ended December 31, 2017, our properties had aggregate net daily production of approximately 22,148 Boe/d.

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.

Recent Developments

Appointment of David J. Sambrooks as President and Chief Executive Officer

On November 1, 2017, David J. Sambrooks was appointed to the position of President and Chief Executive Officer (CEO), effective immediately upon the resignation of the former President and CEO, Frederic Brace. The Board of Directors of the Company (the Board) also approved an increase in the number of directors, from seven directors to eight directors, and Mr. Sambrooks was appointed to the Board, effective concurrently with his appointment as President and CEO.

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. Further information is set forth in 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.

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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 . On May 4, 2017, our common stock began trading on the NYSE 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 natural 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.

Average market prices for oil and NGLs have historically experienced significant volatility. 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 .

Beginning January 1, 2018, Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) 2014-09 becomes effective for us. See Critical Accounting Policies and Estimates below as well as Recent Accounting Pronouncements in Note 4. Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements set forth in Part IV, Item 15 of this Annual Report on Form 10-K, for year ended December 31, 2017 for further discussion of anticipated updates to our revenues under FASB Accounting Standards Codification (ASC) 606.

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The following table sets forth information regarding our oil, NGLs and natural gas revenues for the year ended December 31, 2017, the Successor Period, the Predecessor Period and the year ended December 31, 2015 (in thousands):

	Crude Oil	Natural Gas	NGLs	Total
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 (October 20, 2016)	$ 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 (December 31, 2016)	$ 25,549	$ 13,635	$ 8,391	$ 47,575
Changes due to volumes	90,180	46,666	34,395	171,241
Changes due to price	1,354	(593)	1,326	2,087
Revenues for the Successor Period (December 31, 2017)	$ 117,083	$ 59,708	$ 44,112	$ 220,903

Oil, NGLs and Natural Gas Pricing

The following table sets forth information regarding average realized sales prices for the year ended December 31, 2017, the Successor Period, the Predecessor Period and the year ended December 31, 2015:

	Successor		Predecessor
		For the Period October 21, 2016	