GOODRICH PETROLEUM CORP
Form 10-K
March 03, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 001-12719

GOODRICH PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	76-0466193
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 Louisiana, Suite 700 Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(Registrant's telephone number, including area code) (713) 780-9494
Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, par value $0.01 per share	OTC Marketplace
(Title of Each Class)	(Name of Each Exchange)

Securities Registered Pursuant to Section 12(g) of the Act:

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No ý
Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý
Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

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 of this Form 10-K or any amendment to this Form 10-K. ¨

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

Large accelerated filer ¨ Accelerated filer o

Non-accelerated filer ¨ Smaller reporting company x

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

The aggregate market value of the Common Stock, par value $0.20 per share, held by non-affiliates (based upon the closing sales price on the OTC Market on June 30, 2016, the last business day of the Predecessor registrant's most recently completed second fiscal quarter) was approximately $2.3 million. The number of shares of the Successor registrant's common stock par value $0.01 per share, outstanding as of February 24, 2017 was 9,108,826.

Indicate by check mark whether the Registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes X No

Documents Incorporated By Reference:

Certain information called for in Items 10, 11, 12, 13 and 14 of Part III is incorporated by reference to the registrant's definitive proxy statement for its annual meeting of stockholders, or will be included in an amendment to this Annual Report on Form 10-K.

GOODRICH PETROLEUM CORPORATION
ANNUAL REPORT ON FORM 10-K
FOR THE FISCAL YEAR ENDED
December 31, 2016

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PART I

Items 1. and 2. Business and Properties

General

Goodrich Petroleum Corporation, a Delaware corporation (together with its subsidiary, "we," "our," or "the Company") formed in 1995, is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in (i) Northwest Louisiana and East Texas, which includes the Haynesville Shale Trend, (ii) Southwest Mississippi and Southeast Louisiana which includes the Tuscaloosa Marine Shale Trend ("TMS"), and (iii) South Texas, which includes the Eagle Ford Shale Trend. We own interests in 156 producing oil and natural gas wells located in 39 fields in eight states. At December 31, 2016, we had estimated proved reserves of approximately 303 Bcfe, comprised of 286 Bcf of natural gas and 2.8 MMBbls of oil and condensate.

We operate as one segment as each of our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined by accounting standards related to disclosures about segments of an enterprise.

Voluntary Reorganization under Chapter 11 of the Bankruptcy Code

On April 15, 2016 (the "Petition Date"), we and our subsidiary Goodrich Petroleum Company, L.L.C. (the "Subsidiary", and together with us, the "Debtors") filed voluntary petitions (the "Bankruptcy Petitions" and, the cases commenced thereby, the "Chapter 11 Cases") seeking relief under Chapter 11 of Title 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (the "Bankruptcy Court"), to pursue a Chapter 11 plan of reorganization. The Company filed a motion with the Bankruptcy Court seeking joint administration of the Chapter 11 Cases under the caption In re Goodrich Petroleum Corporation, et al. (Case No. 16-31975). The Debtors received Bankruptcy Court confirmation of their joint plan of reorganization on September 28, 2016 and subsequently emerged from bankruptcy on October 12, 2016. Although the Company is no longer a debtor-in-possession, the Company was a debtor-in-possession for the entire quarter ended September 30, 2016. As such, aspects of the Company's bankruptcy proceedings and related matters are described below in order to provide context and explain a part of our financial condition and results of operations for the period presented. The Company is accounting for the bankruptcy in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 852, "Reorganizations". The Company filed a series of first day motions with the Bankruptcy Court that allowed it to continue to conduct business without interruption. These motions were designed primarily to minimize the impact on the Company's operations, customers and employees.

Prior to filing the Chapter 11 Cases, on March 28, 2016, the Company entered into a Restructuring Support Agreement (the "Restructuring Support Agreement") with certain holders of the Company's 8.0% Second Lien Senior Secured Notes due 2018 (the "8.0% Second Lien Notes") and 8.875% Second Lien Senior Secured Notes due 2018 (the "8.875% Second Lien Notes" and together with the 8.0% Second Lien Notes, the "Second Lien Notes"). The Restructuring Support Agreement set forth, subject to certain conditions, the commitment to and obligations of, on the one hand, the Debtors, and on the other hand, the certain holders, in connection with the restructuring of the Company's Second Lien Notes, 3.25% Convertible Senior Notes due 2026 (the "2026 Notes"), 5.0% Convertible Senior Notes due 2029 (the "2029 Notes"), 5.0% Convertible Senior Notes due 2032 (the "2032 Notes"), 5.0% Convertible Exchange Senior Notes due 2032 (the "2032 Exchange Notes"), 8.875% Senior Notes due 2019 ("the 2019 Notes"), 5.375% Series B Cumulative Convertible Preferred Stock ("Series B Preferred Stock"), 10% Series C Cumulative Preferred Stock ("Series C Preferred Stock"), 9.75% Series D Cumulative Preferred Stock ("Series D Preferred Stock"), 10% Series E Cumulative Convertible Preferred Stock ("Series E Preferred Stock") and the Company's common stock, par value $0.20 per share, pursuant to the Company's Joint Prepackaged Plan of Reorganization filed under Chapter 11 of the United States Bankruptcy Code on the Petition Date. On May 21, 2016, the Restructuring Support Agreement was terminated automatically pursuant to its terms as an Assumption Order approving the Restructuring Support Agreement was not entered by the Bankruptcy Court within thirty-five days of the Petition Date. See discussion on the Company's Joint Prepackaged Plan of Reorganization below.

The Chapter 11 Cases described above constituted an event of default that accelerated the Company's obligations under all of its outstanding debt instruments. The agreements governing the Company's debt instruments at the time provided that as a result of the Bankruptcy Petitions, the principal and interest due thereunder was immediately due and payable. However, any efforts to enforce such payment obligations under the Company's debt instruments were automatically stayed as a result of the Chapter 11 Cases, and the creditors' rights of enforcement in respect of the debt instruments were subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.

On April 18, 2016, the Bankruptcy Court issued certain additional interim and final orders with respect to the Debtors' first-day motions and other operating motions that allowed the Debtors to operate their businesses in the ordinary course. Subject to certain exceptions under the Bankruptcy Code, the filing of the Bankruptcy Petitions automatically enjoined, or stayed, the continuation of any judicial or administrative proceedings or other actions against the Debtors or their property to recover, collect or secure a claim arising prior to the filing of the Bankruptcy Petitions. Thus, for example, most creditor actions to obtain possession of property from the Debtors, or to create, perfect or enforce any lien against the Debtors' property, or to collect on monies owed or otherwise exercise rights or remedies with respect to a pre-petition claim were enjoined.

During the Chapter 11 Cases, the Company conducted normal business activities and was authorized to continue to pay and has paid (subject to limitations applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders, critical vendors and other third parties, such as royalty holders and partners.

On July 25, 2016 the Company entered into and filed a motion with the Bankruptcy Court to approve a commitment letter (the "Commitment Letter") with a group of investors for the new issuance of 13.50% Convertible Second Lien Senior Secured Notes in the initial aggregate principal amount of $40.0 million (the "Convertible Second Lien Notes"). The Bankruptcy Court approved the motion on August 4, 2016 which allowed the Company to submit a revised plan of organization to the Bankruptcy Court. The approval by the Bankruptcy Court of the Commitment Letter terminated the bid procedures that were previously approved by the Bankruptcy Court on July 1, 2016.

Commitment Letter

The Commitment Letter provided for the issuance of $40.0 million in Convertible Second Lien Notes that mature on the later of August 30, 2019 or six months after the maturity of the Exit Credit Agreement (including all amendments, the "Exit Credit Facility"). Interest on the Convertible Second Lien Notes will accrue at a rate of 13.50% per annum and be paid quarterly in cash or paid in kind by adding to the principal at the option of the issuer. The Convertible Second Lien Notes will convert at the option of the purchaser into a number of common shares equal to 15% of the common shares of the reorganized company. Upon closing, purchasers of the Convertible Second Lien Notes (i)were issued 10-year costless warrants for common stock equal to 20% of the common shares of the reorganized company, (ii) took a second priority lien on all assets of the reorganized company, and (iii) received the right to appoint two members to the Board of Directors (the "Board") of the reorganized company. A total of $20.0 million in proceeds from the issuance of the Convertible Second Lien Notes were used to repay amounts outstanding under the existing Second Amended and Restated Credit Agreement (including all amendments, the "Senior Credit Facility") and $20.0 million in proceeds will be used to fund the Company's Haynesville Shale Trend drilling program.

Plan of Reorganization

The significant features of the Plan of Reorganization (the "Plan of Reorganization") confirmed by the Bankruptcy Court are as follows:

1. Each holder of an allowed priority claim (other than a priority tax claim or administrative claim) received either: (a) cash equal to the full allowed amount of its claim or (b) such other treatment as may otherwise be agreed to by such holder, the Debtors, the holders of at least 50% in principal amount of the Second Lien Notes (the "Majority Consenting Noteholders"), and the purchasers of the new Convertible Second Lien Notes ("New 2L Notes Purchasers");

2. Each holder of a secured claim (other than a priority tax claim, Senior Credit Facility claim, or Second Lien Notes claim) received, at the Debtors' election and with the consent of the Majority Consenting Noteholders, either: (a) cash equal to the full allowed amount of its claim, (b) reinstatement of such holder's claim, (c) the return or abandonment of the collateral securing such claim to such holder, or (d) such other treatment as may otherwise be agreed to by such holder, the Debtors, the Majority Consenting Noteholders, and the New 2L Notes Purchasers;

3. The Senior Credit Facility claims were paid cash in an amount sufficient to reduce the Senior Credit Facility claims to a balance of $20.0 million while the remaining $20.0 million owed was to be refinanced into a new senior secured term loan credit facility;

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4. The Second Lien Notes claims were deemed allowed in the aggregate amount of $175.0 million of principal plus accrued and unpaid interest through the Petition Date. Except to the extent a holder of a Second Lien Note claim agreed in writing to less favorable treatment, in full and final satisfaction, settlement, release, and discharge of, and in exchange for, each Second Lien Notes claim, each holder of a Second Lien Notes claim received their pro rata share of 98% of the new equity interests in the reorganized company (the “New Equity Interests”), subject to dilution on account of (i) the management incentive plan, (ii) the potential conversion of the Convertible Second Lien Notes, (iii) the warrants granted to the New 2L Notes Purchasers, and (iv) the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million;

5. Holders of unsecured notes claims received, pro rata with holders of other general unsecured claims, their pro rata share of the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million; plus its pro rata share of 2% of the New Equity Interests that are subject to dilution on account of (i) the management incentive plan, (ii) the potential conversion of the Convertible Second Lien Notes, (iii) the warrants granted to the New 2L Notes Purchasers, and (iv) the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal of $230.0 million;

6. Holders of allowed general unsecured claims had the option to elect on their ballot to (a) receive, pro rata with holders of unsecured notes claims, its pro rata share of the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million; plus its pro rata share of 2% of the New Equity Interests that are subject to dilution on account of (i) the management incentive plan, (ii) the potential conversion of the Convertible Second Lien Notes, (iii) the warrants granted to the New 2L Notes Purchasers, and (iv) the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million, or (b) treat its allowed general unsecured claim as a convenience class claim by releasing any claims in excess of $10,000;

7. Holders of convenience class claims received either: (a) cash equal to the full allowed amount of such holder’s claim or (b) such lesser treatment as may otherwise be agreed to by such holder, the Debtors, the Majority Consenting Noteholders and the New 2L Notes Purchasers;

8. Equity interests in the Subsidiary were canceled and extinguished without further notice to, approval of, or action by any entity, and each holder of an equity interest in the Subsidiary did not receive any distribution or retain any property on account of such equity interest in the Subsidiary. Equity interests in the Company were canceled and extinguished without further notice to, approval of, or action by any entity, and each holder of an equity interest in the Company did not receive any distribution or retain any property on account of such equity interest in the Company.

The Company's Plan of Reorganization was confirmed by the Bankruptcy Court on September 28, 2016 and we emerged from bankruptcy on October 12, 2016 (the "Effective Date").

All references made to “Successor” or “Successor Company” relate to Goodrich on and subsequent to the Effective Date. References to the “Successor 2016 Period” relate to the period from October 13, 2016 to December 31, 2016. References to “Predecessor” or “Predecessor Company” refer to Goodrich prior to the Effective Date. References to the “Predecessor 2016 Period” relate to the period from January 1, 2016 to October 12, 2016.

Available Information

Our principal executive offices are located at 801 Louisiana Street, Suite 700, Houston, Texas 77002.

Our website address is http://www.goodrichpetroleum.com. We make available, free of charge through the Investor Relations portion of our website, our annual reports on Form 10-K, proxy statement, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission ("SEC"). Reports of beneficial ownership filed pursuant to Section 16(a) of the Exchange Act are also available on our website. Information contained on our website is not part of this report.

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at http://www.sec.gov.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

As used herein, the following terms have specific meanings as set forth below:

Bbls	Barrels of crude oil or other liquid hydrocarbons
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Boe	Barrel of crude oil or other liquid hydrocarbons equivalent
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons
Mboe	Thousand barrels of crude oil equivalent
Mcf	Thousand cubic feet of natural gas
Mcfe	Thousand cubic feet equivalent
MMBbls	Million barrels of crude oil or other liquid hydrocarbons
MMBtu	Million British thermal units
Mmcf	Million cubic feet of natural gas
Mmcfe	Million cubic feet equivalent
MMBoe	Million barrels of crude oil or other liquid hydrocarbons equivalent
NGL	Natural gas liquids
U.S.	United States

Crude oil and other liquid hydrocarbons are converted into cubic feet of natural gas equivalent based on six Mcf of natural gas to one barrel of crude oil or other liquid hydrocarbons.

Developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserves estimates if the extraction is by means not involving a well.

Development well is a well drilled within the proved area of an oil or natural gas field to the depth of a stratigraphic horizon known to be productive.

Dry hole is an exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil-and-natural gas producing activities.

Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well or a stratigraphic test well.

Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and natural gas lease or license assigns the working interest or a portion thereof to another party who desires to drill on the leased or licensed acreage. Generally, the assignee is required to drill one or more wells to earn its interest in the acreage. The assignor (the “farmor”) usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farm-in”, while the interest transferred by the assignor is a “farm-out”.

Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition. The SEC provides a complete definition of field in Rule 4-10 (a) (15).

Gross well or acre is a well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest.

Net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions of whole numbers.

PV-10 is the pre-tax present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying the 12-month average price for the year and holding that price constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions). PV-10 is not a financial measure that is in accordance with US GAAP. The SEC methodology for computing the 12-month average price is discussed in the definition of "Proved reserves" below.

Productive well is an exploratory, development or extension well that is not a dry well.

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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. As used in this definition, "existing economic conditions" include prices and costs at which economic producibility from a reservoir is to be determined. The prices shall be 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 on future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10 (a) (22) of Regulation S-X.

Reasonable certainty means a high degree of confidence that the quantities will be recovered, if deterministic methods are used. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease. The deterministic method of estimating reserves or resources uses a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation. The probabilistic method of estimation of reserves or resources uses the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) to generate a full range of possible outcomes and their associated probabilities of occurrence.

Reserves are 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. In addition, there must exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.

Undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Working interest is the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.
Workover is a series of operations on a producing well to restore or increase production.

Oil and Natural Gas Operations and Properties

As of December 31, 2016, nearly all of our proved oil and natural gas reserves were located in Louisiana, Texas and Mississippi. We spent substantially all of our 2016 capital expenditures of $6.3 million in these areas, with $1.5 million, or 24%, spent on the TMS and $4.1 million, or 65% spent on the Haynesville Shale Trend. Our total capital expenditures, including accrued costs for services performed during 2016, consisted of $5.8 million for drilling and completion costs, and $0.5 million for leasehold acquisitions and extensions.

Beginning in the second half of 2014, commodity prices, particularly oil, began to decline sharply. The decline became precipitous late in the fourth quarter of 2014 and into 2016. The duration and significant magnitude of this price decline has materially and adversely impacted our results of operations and led to substantial changes in our operating and drilling programs for 2016. As a result, during 2016, we focused on managing our balance sheet to reduce leverage and preserve liquidity during this low commodity price environment.

The table below details our acreage positions, average working interest and producing wells as of December 31, 2016.

Field or Area	Acreage As of December 31, 2016 Gross	Net	Average Producing Well Working Interest		Producing wells at December 31, 2016
Tuscaloosa Marine Shale Trend	215,077	155,682	65	%	38
Haynesville Shale Trend	47,731	23,345	35	%	89
Eagle Ford Shale Trend	32,430	14,148	—		—
Other	33,125	7,492	17	%	29

Haynesville Shale Trend

As of December 31, 2016, we have acquired or farmed-in leases totaling approximately 47,700 gross (23,300 net) acres in the Haynesville Shale Trend. During 2016, we added 2 gross (.35 net) wells to production in the Chesapeake operated portion of our acreage position. Our Haynesville Shale Trend drilling activities are located in leasehold areas in East Texas and Northwest Louisiana.

Tuscaloosa Marine Shale Trend

As of December 31, 2016, we have acquired approximately 215,100 gross (155,700 net) lease acres in the TMS, an oil shale play in Southwest Mississippi and Southeast Louisiana. During 2016, we did not conduct any drilling operations and did not add any wells to production. As of December 31, 2016, we had 2 wells waiting on completion operations.

Eagle Ford Shale Trend

As of December 31, 2016, we have acquired or farmed-in leases totaling approximately 32,400 gross (14,100 net) lease acres. As part of our efforts in 2015 to reduce leverage and preserve liquidity, we sold all of our proved reserves in the Eagle Ford Shale Trend and a portion of the associated leasehold. We closed the Eagle Ford Shale Trend sale on September 4, 2015.

Other

As of December 31, 2016, we maintained ownership interests in acreage and/or wells in several additional fields.

See "Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations" in this Annual Report on Form 10-K for additional information on our recent operations in the TMS, Haynesville Shale Trend and Eagle Ford Shale Trend.

Oil and Natural Gas Reserves

The following tables set forth summary information with respect to our proved reserves as of December 31, 2016 and 2015, as estimated by Netherland, Sewell & Associates, Inc. ("NSAI") and by Ryder Scott Company ("RSC") our independent reserve engineers. All of our proved reserves estimates are independently prepared by NSAI and RSC. NSAI prepared the estimates on all our proved reserves as of December 31, 2016 on properties other than those located in the TMS. RSC prepared the estimate of proved reserves as of December 31, 2016 for our TMS properties. Copies of the summary reserve reports of NSAI and RSC as of December 31, 2016 are included as exhibits to this Annual Report on Form 10-K. For additional information see Supplemental Information "Oil and Natural Gas Producing Activities (Unaudited)" to our consolidated financial statements in "Item 8—Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Proved undeveloped reserves were not included in our December 31, 2015 reserve estimates as the sustained decline in oil and natural gas prices raised substantial doubt at the time, about our ability to continue as a going concern and our ability to adequately finance the development of proved undeveloped reserves in the future.

Net proved reserves and the PV10 estimates at December 31, 2016 below, were calculated using flat, twelve month average commodity prices of $42.75 per barrel and $2.48 per Mmbtu.

	Proved Reserves at December 31, 2016			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	1,988	827	—	2,815
Natural Gas (Mmcf)	23,277	4,266	258,495	286,038
Mcf Natural Gas Equivalent (Mcfe) (2)	35,207	9,225	258,495	302,927
Estimated Future Net Cash Flows				$159,824
PV-10 (3)				$57,086
Discounted Future Income Taxes				(164)
Standardized Measure of Discounted Net Cash Flows (3)				$56,922

	Proved Reserves at December 31, 2015			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	3,184	650	—	3,834
Natural Gas (Mmcf)	29,633	2,218	—	31,851
Mcf Natural Gas Equivalent (Mcfe) (2)	48,737	6,118	—	54,855
Estimated Future Net Cash Flows				$94,811
PV-10 (3)				$69,895
Discounted Future Income Taxes				—
Standardized Measure of Discounted Net Cash Flows (3)				$69,895

(1) Includes condensate.

(2) Based on ratio of six Mcf of natural gas per Bbl of oil and per Bbl of NGLs.

(3) PV-10 represents the discounted future net cash flows attributable to our proved oil and natural gas reserves before income tax, discounted at 10%. PV-10 of our total year-end proved reserves is considered a non-US GAAP financial measure as defined by the SEC. We believe that the presentation of the PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. We further believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our reserves to other companies. See the reconciliation of our PV-10 to the standardized measure of discounted future net cash flows in the table above.

(4) The following table presents our reserves by targeted geologic formation in Mmcfe.

Area	December 31, 2016			
	Proved Developed	Proved Undeveloped	Proved Reserves	% of Total
Tuscaloosa Marine Shale Trend	16,796	—	16,796	6 %
Haynesville Shale Trend	27,260	258,495	285,755	94 %
Other	376	—	376	— %
Total	44,432	258,495	302,927	100%

Reserve engineering is a subjective process of estimating underground accumulations of crude oil, condensate and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may differ from those assumed in these estimates. Therefore, the PV-10 amounts shown above should not be construed as the current market value of the oil and natural gas reserves attributable to our properties.

In accordance with the guidelines of the SEC, our independent reserve engineers' estimates of future net revenues from our estimated proved reserves, and the PV-10 and standardized measure thereof, were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price for the period of January 2016 through December 2016, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For reserves at December 31, 2016, the average twelve month prices used were $2.48 per MMBtu of natural gas and $42.75 per Bbl of crude. These prices do not include the impact of hedging transactions, nor do they include the adjustments that are made for applicable transportation and quality differentials, and price differentials between natural gas liquids and oil, which are deducted from or added to the index prices on a well by well basis in estimating our proved reserves and related future net revenues.

Our proved reserve information as of December 31, 2016 included in this Annual Report on Form 10-K was estimated by our independent petroleum engineers, NSAI and RSC, in accordance with petroleum engineering and evaluation principles and definitions and guidelines set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Natural Gas Reserve Information promulgated by the Society of Petroleum Engineers. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Natural Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our principal engineer has over 30 years of experience in the oil and natural gas industry, including over 25 years as a reserve evaluator, trainer or manager. Further professional qualifications of our principal engineer include a degree in petroleum engineering, extensive internal and external reserve training, and experience in asset evaluation and management. In addition, the principal engineer is an active participant in professional industry groups and has been a member of the Society of Petroleum Engineers for over 30 years.

Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria is provided to them. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

We consider providing independent fully engineered third-party estimates of reserves from nationally reputable petroleum engineering firms, such as NSAI and RSC, to be the best control in ensuring compliance with Rule 4-10 of Regulation S-X for reserve estimates.

While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the NSAI and RSC reserve reports are reviewed by our senior management with representatives of NSAI and RSC and our internal technical staff. Additionally, our senior management reviews and approves any internally estimated significant changes to our proved reserves semi-annually.

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. To achieve reasonable certainty, NSAI and RSC 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, well logs, geologic maps, available downhole and production data, seismic data and well test data.

Our total proved reserves at December 31, 2016, as estimated by NSAI and RSC, were 302,927 Mmcfe, consisting of 286 Bcf of natural gas and 2.8 MMBbls of oil and condensate. In 2016 we added approximately 264.2 Mmcfe related to our drilling activities in the Haynesville Shale Trend. We had negative revisions of approximately 7.7 Mmcfe, divestitures of 3.0 Mmcfe and produced 8.4 Mmcfe in 2016. We are employing new completion techniques on our

Haynesville Shale Trend wells which have been proven on the two successful wells we drilled in 2016. These well results in conjunction with our acreage position and our new financial ability to develop our Haynesville Shale Trend properties allowed us to add the Haynesville Shale Reserves as of December 31, 2016.

We did not report any proved undeveloped reserves at December 31, 2015, consequently, we did not have any proved undeveloped reserves to convert to proved developed reserves during 2016.

Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2016:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Tuscaloosa Marine Shale Trend:						
Southeast Louisiana	17	12	—	—	17	12
Southwest Mississippi	21	13	—	—	21	13
Haynesville Shale Trend:						
East Texas	—	—	6	4	6	4
Northwest Louisiana	—	—	83	27	83	27
Other	10	1	19	4	29	5
Total Productive Wells	48	26	108	35	156	61

(1) Royalty and overriding interest wells that have immaterial values are excluded from the above table. As of December 31, 2016, only three wells with royalty-only and overriding interests-only are included.

(2) Net working interest.

Productive wells consist of producing wells and wells capable of production, including wells awaiting pipeline connections. A gross well is a well in which we maintain an ownership interest, while a net well is deemed to exist when the sum of the fractional working interests owned by us equals one. Wells that are completed in more than one producing horizon are counted as one well. Of the gross wells reported above, four wells had completions in multiple producing horizons.

Acreage

The following table summarizes our gross and net developed and undeveloped acreage under lease as of December 31, 2016. Acreage in which our interest is limited to a royalty or overriding royalty interest is excluded from the table.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Tuscaloosa Marine Shale Trend:						
Southwest Mississippi	23,179	19,211	53,235	26,731	76,414	45,942
Southeast Louisiana	27,120	20,305	111,543	89,435	138,663	109,740
Haynesville Shale Trend:						
East Texas	12,578	7,502	292	292	12,870	7,794
Northwest Louisiana	34,861	15,720	—	—	34,861	15,720
Eagle Ford Shale Trend:						
South Texas	—	—	32,430	14,148	32,430	14,148
Other	28,488	6,636	4,637	687	33,125	7,323
Total	126,226	69,374	202,137	131,293	328,363	200,667

Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to the extent that would permit the production of commercial quantities of oil or natural gas, regardless of whether or not such acreage contains proved reserves. As is customary in the oil and natural gas industry, we can retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the remaining primary term of such a lease. The oil and natural gas leases in which we have an interest are for varying primary terms; however, most of our developed lease acreage is beyond the primary term and is held so long as oil or natural gas is produced.

Lease Expirations

We have undeveloped lease acreage, excluding optioned acreage, that will expire during the next four years, unless the leases are converted into producing units or extended prior to lease expiration. The following table sets forth the lease expirations as of December 31, 2016:

Year	Net Acreage
2017	66,634
2018	22,605
2019	3,801
2020	12,835

Operator Activities

We operate a majority of our producing properties by value, and will generally seek to become the operator of record on properties we drill or acquire. Chesapeake Energy Corporation ("Chesapeake") continues to operate a majority of our jointly owned Northwest Louisiana acreage in the Haynesville Shale Trend.

Drilling Activities

The following table sets forth our drilling activities for the last three years. As denoted in the following table, "gross" wells refer to wells in which a working interest is owned, while a "net" well is deemed to exist when the sum of the fractional working interests we own in gross wells equals one.

	Year Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	2	0.4	8	6.7	19	13.0
Non-Productive	—	—	—	—	—	—
Total	2	0.4	8	6.7	19	13.0
Exploratory Wells:						
Productive	—	—	—	—	4	3.2
Non-Productive	—	—	—	—	—	—
Total	—	—	—	—	4	3.2
Total Wells:						
Productive	2	0.4	8	6.7	23	16.2
Non-Productive	—	—	—	—	—	—
Total	2	0.4	8	6.7	23	16.2

At December 31, 2016, we had 2 gross (1.7 net) development wells waiting to be completed.

Net Production, Unit Prices and Costs

The following table presents certain information with respect to oil and natural gas production attributable to our interests in all of our properties (including two fields which have attributed more than 15% of our total proved reserves as of December 31, 2016), the revenue derived from the sale of such production, average sales prices received and average production costs during each of the years in the three-year period ended December 31, 2016.

	Sales Volumes Natural Gas Mmcf	Oil & Condensate MBbls	Total Mmcfe	Average Sales Prices (1) Natural Gas Mcf	Oil & Condensate Per Bbl	Total Per Mcfe	% of Total Revenue		Average Production Cost (2) Per Mcfe
For Year 2016:									
TMS	—	473	2,837	$—	$ 40.81	$6.80	34	%	$ 1.98
Haynesville Shale Trend	5,471	—	5,471	1.44	—	1.44	66	%	0.48
Other	84	3	102	3.00	39.71	3.65	—	%	3.69
Total	5,555	476	8,410	$1.47	$ 40.80	$3.28	100	%	$ 1.02
For Year 2015:									
TMS	—	883	5,298	$—	$ 49.60	$8.27	55	%	$ 1.36
Haynesville Shale Trend	7,018	—	7,018	1.67	—	1.67	15	%	0.39
Eagle Ford Shale Trend (3)	776	453	3,494	2.39	46.30	6.54	29	%	1.37
Other	190	—	190	3.58	—	3.58	1	%	4.55
Total	7,984	1,336	16,000	$1.79	$ 48.50	$4.94	100	%	$ 0.97
For Year 2014:									
TMS	—	738	4,428	$—	$ 90.55	$15.09	32	%	$ 1.07
Haynesville Shale Trend	10,176	1	10,182	3.08	86.36	3.08	15	%	0.44
Eagle Ford Shale Trend (3)	1,321	928	6,889	5.70	89.69	13.31	44	%	1.62
Other	3,483	25	3,633	5.01	90.83	5.72	9	%	2.50
Total	14,980	1,692	25,132	$3.75	$ 90.08	$8.30	100	%	$ 1.18

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.
(3) We sold our Eagle Ford Shale Trend proved reserves and a portion of the associated leasehold on September 4, 2015.

Oil and Natural Gas Marketing and Major Customers

Marketing. Our natural gas production is sold under spot or market-sensitive contracts to various natural gas purchasers on short-term contracts. Our oil production is sold to various purchasers under short-term rollover agreements based on current market prices.

Customers. Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. The revenues compared to our total oil and natural gas revenues from the top purchasers for the years ended December 31, 2016, and 2015 are as follows:

	Year Ended December 31, 2016	2015
Genesis Crude Oil LP	44%	26%
Sunoco, Inc.	30%	17%
Occidental Energy MA	13%	—%
BP Energy Company	—%	31%

Competition

The oil and natural gas industry is highly competitive. Major and independent oil and natural gas companies, drilling and production acquisition programs and individual producers and operators are active bidders for desirable oil and natural gas properties, as well as the equipment and labor required to operate those properties. Many competitors have financial resources substantially greater than ours, and staffs and facilities substantially larger than us.

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Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas. Demand for oil and natural gas is typically higher in the fourth and first quarters resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Employees

At February 24, 2017 we had 43 full-time employees in our Houston administrative office and 4 in our field offices, none of whom is represented by any labor union. We regularly use the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site supervision, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for us, including gauging, maintenance, dispatching, inspection, and well testing.

Regulations

The availability of a ready market for any oil and natural gas production depends upon numerous factors beyond our control. These factors include regulation of oil and natural gas production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be “shut-in” because of an oversupply of natural gas or the lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment.

Environmental and Occupational Health and Safety Matters

General

Our operations are subject to stringent and complex federal, regional, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. Compliance with these laws and regulations may require the acquisition of permits before drilling or other related activity commences, restrict the type, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling and production activities on certain lands lying within wilderness, wetlands and other protected areas, impose specific health and safety criteria addressing worker protection, and impose substantial liabilities for pollution arising from drilling and production operations. Environmental laws and regulations also impose certain plugging and abandonment and site reclamation requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that may limit or prohibit 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. Additionally, the trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and, any changes in environmental laws and regulations that result in more stringent and costly well construction, drilling, waste management or completion activities or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business. Environmental laws and regulations change frequently, and there is no assurance that we will be able to remain in compliance in the future with such existing or any new laws and regulations or that such future compliance will not have a material adverse effect on our business and operating results. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future.

The following is a summary of the more significant existing environmental laws to which our business operations are subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Hazardous Substances and Wastes

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The Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred, and companies that disposed or arranged for the disposal of hazardous substances released at the site. Under CERCLA, these persons may be subject to joint and several, strict liabilities for remediation cost at the site, natural resource damages and for the costs of certain health studies. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. We generate materials in the course of our operations that are regulated as hazardous substances.

We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes that impose stringent requirements related to the handling and disposal of non-hazardous and hazardous wastes. Wastes, including drilling fluids and produced water, generated in the exploration or production of oil and natural gas are exempt from classification as hazardous wastes under RCRA. Proposals have been made from time to time to eliminate this exemption, which, if adopted, would cause some of these wastes to be regulated under the more rigorous RCRA hazardous waste standards. For example, in December 2016, the U.S. Environmental Protection Agency ("EPA") and certain environmental organizations entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. A loss of this RCRA exemption could result in increased costs to us and the oil and gas industry in general to manage and dispose of generated wastes. Moreover, some ordinary industrial wastes which we generate, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous wastes if they have hazardous characteristics.

We currently own or lease, and in the past have owned or leased, properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes and petroleum hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties whose treatment and disposal of hazardous substances, wastes and petroleum hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to undertake costly site investigations, remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges and Subsurface Injections

The Federal Water Pollution Control Act, as amended, ("Clean Water Act"), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into state and federal waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure ("SPCC") plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. In September 2015, new EPA and U.S. Army Corps of Engineers (the "Corps") rules defining the scope of the EPA's and the Corps' jurisdiction became effective. To the extent the rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of CWA programs, and implementation of the rule has been stayed pending resolution of the court challenge. Most recently, in

January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction over the challenge to the rule rests with the federal district or appellate courts. Litigation surrounding the rule is ongoing. The process for obtaining permits has the potential to delay the development of natural gas and oil projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In addition, the Oil Pollution Act of 1990, as amended ("OPA"), imposes a variety of requirements related to the prevention of oil spills into navigable waters as well as liabilities for oil cleanup costs, natural resource damages and a variety of public and private damages that may result from such oil spills.

The disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended ("SDWA"), and analogous state laws. The SDWA's Underground Injection Control Program establishes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities as well as a prohibition against the migration of fluid containing any contaminants into underground sources of drinking water. State programs may have analogous permitting and operational requirements. In response to concerns related to increased seismic activity in the vicinity of injection wells, regulators in some states are considering additional requirements related to seismic safety. For example, the Texas Railroad Commission ("RRC") adopted new oil and gas permit rules in October 2014 for wells used to dispose of saltwater and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to conduct continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position. In addition, any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for property damages and personal injury.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. For example, the EPA has taken the following actions and issued: guidance under the SDWA for hydraulic fracturing activities involving the use of diesel fuel; final regulations under the federal Clean Air Act governing performance standards, including standards for the capture of volatile organic compounds and methane emissions released during hydraulic fracturing; an advanced notice of proposed rulemaking in March 2014 under the Toxic Substances Control Act that would require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the Bureau of Land Management ("BLM") finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision has not yet been issued.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. The EPA has not proposed to take any action in response to the report's findings.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Louisiana and Texas, 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. Moreover, some states and local governments have enacted laws or regulations limiting hydraulic fracturing within their borders or prohibiting the activity altogether. In the event that 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.

Air Emissions

The Clean Air Act ("CAA") and comparable state laws, regulate emissions of various air pollutants from many sources in the United States, including crude oil and natural gas production activities through air emissions standards, construction and operating programs and the imposition of other compliance requirements. These laws and any implementing 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. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. 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 October 2015, the EPA lowered the National Ambient Air Quality Standard (“NAAQS”) for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, in June 2016, the EPA finalized rules under the CAA regarding criteria for aggregating multiple sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities (such as tank batteries), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. Compliance with these requirements could increase our costs of development and production significantly.

Climate Change

The EPA has determined that greenhouse gases present an endangerment to public health and the environment and has issued regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources of greenhouse gas emissions. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from a variety of sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions from completions and workovers from hydraulically fractured oil wells. Also, in June 2016, the EPA finalized rules that establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The BLM finalized similar rules in November 2016 that limit methane emissions from new and existing oil and gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. However, both the U.S. House of Representatives and the Senate have introduced resolutions seeking to repeal the BLM methane rules under the Congressional Review Act and future implementation of the BLM methane rules is uncertain. However, the BLM and the EPA methane rules have substantial similarities with respect to pollution control equipment and leak detection and repair requirements. Compliance with rules to control methane emissions will likely require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks, and the increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third party contractors to assist with and verify compliance. These new and proposed rules could result in increased compliance costs on our operations.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and many states have established greenhouse gas cap and trade programs. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for the oil and natural gas we produce, which could in turn have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases 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. Such climatic events could have an adverse effect on our financial condition and results of operations.

Endangered Species

The Federal Endangered Species Act, as amended ("ESA"), and analogous state laws restrict activities that could have an adverse effect on threatened or endangered species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. Moreover, as a result of a court settlement the U.S. Fish and Wildlife Service is required to make a determination on listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2018 fiscal year. The presence of protected species or the designation of previously unidentified endangered or threatened species could impair our ability to timely complete well drilling and development and could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee Health and Safety

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended, ("OSHA"), and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act, as amended, and implementing regulations and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local governmental authorities and citizens.

Other Laws and Regulations

State statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. In addition, there are state statutes, rules and regulations governing conservation matters, including the unitization or pooling of oil and natural gas properties, establishment of maximum rates of production from oil and natural gas wells and the spacing, plugging and abandonment of such wells. Such statutes and regulations may limit the rate at which oil and natural gas could otherwise be produced from our properties and may restrict the number of wells that may be drilled on a particular lease or in a particular field.

Item 1A. Risk Factors

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

The Company has made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with Company management, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended concerning the Company’s operations, economic performance and financial condition. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and natural gas properties, marketing and midstream activities, and also include those statements accompanied by or that otherwise include the words “may,” “could,” “believes,” “expects,” “anticipates,” “intends,’ “estimates,” “projects,” “predicts,” “target,” “goal,” “plans,” “objective,” “potential,” “should,” or similar expressions or variat such expressions that convey the uncertainty of future events or outcomes. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. The Company has based these forward-looking statements on its current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate under the circumstances. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made; the Company undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company’s expectations include, but are not limited to, the following risk and uncertainties:

- the market prices of oil and natural gas;
- volatility in the commodity-futures market;
- financial market conditions and availability of capital;
- future cash flows, credit availability and borrowings;
- sources of funding for exploration and development;
- our financial condition;
- our ability to repay our debt;
- the securities, capital or credit markets;
- planned capital expenditures;
- future drilling activity;
- uncertainties about the estimated quantities of our oil and natural gas reserves;
- production;
- hedging arrangements;
- litigation matters;
- pursuit of potential future acquisition opportunities;
- general economic conditions, either nationally or in the jurisdictions in which we are doing business;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, hydraulic-fracturing regulation, drilling and permitting regulations, derivatives reform, changes in state and federal corporate taxes, environmental regulation, environmental risks and liability under federal, state and foreign and local environmental laws and regulations;
- the creditworthiness of our financial counterparties and operation partners; and

- other factors discussed below and elsewhere in this Annual Report on Form 10-K and in our other public filings, press releases and discussions with our management.

We recently emerged from bankruptcy, which could adversely affect our business and relationships.

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

- key suppliers could terminate their relationship or require financial assurances or enhanced performance;
- the ability to renew existing contracts and compete for new business may be adversely affected;
- the ability to attract, motivate and/or retain key executives and employees may be adversely affected;
- employees may be distracted from performance of their duties or more easily attracted to other employment opportunities; and
- competitors may take business away from us, and our ability to attract and retain customers may be negatively impacted.

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

Our actual financial results after emergence from bankruptcy may not be comparable to our historical financial information as a result of the implementation of our Plan of Reorganization and the transactions contemplated thereby and our adoption of fresh start accounting.

In connection with the disclosure statement we filed with the Bankruptcy Court, and the hearing to consider confirmation of the Plan of Reorganization, we prepared projected financial information to demonstrate to the Bankruptcy Court the feasibility of the plan of reorganization and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

In addition, upon our emergence from bankruptcy, we adopted fresh start accounting. Accordingly, our future financial conditions and results of operations may not be comparable to the financial condition or results of operations reflected in the Company’s historical financial statements. The lack of comparable historical financial information may discourage investors from purchasing our common stock.

There is a limited trading market for our securities and the market price of our securities is subject to volatility.

Upon our emergence from bankruptcy, our old common stock was canceled and we issued new common stock. Our common stock is now listed on the over-the-counter market. The market price of our common stock could be subject to wide fluctuations in response to, and the level of trading that develops with our common stock may be affected by numerous factors, many of which are beyond our control. These factors include, among other things, our new capital structure as a result of the transactions contemplated by the Plan of Reorganization, our limited trading history subsequent to our emergence from bankruptcy, 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 general economic and market conditions and other factors that may affect our future results, including those described in this Part I, Item 1A of this Annual Report on Form 10-K. No assurance can be given that an active market will develop for the common stock or as to the liquidity of the trading market for the common stock. The common stock may be traded only infrequently in transactions arranged through brokers or otherwise, and reliable market quotations may not be available. Holders of our common stock may experience difficulty in reselling, or an inability to sell, their shares. In addition, if an active trading market does not develop or is not maintained, significant sales of our common stock, or the expectation of these sales, could materially and adversely affect the market price of our common stock.

The Company intends to join a national securities exchange. However, no assurances can be given regarding the Company's ability to do so in a timely manner or at all.

Upon our emergence from bankruptcy, the composition of our Board changed significantly.

Pursuant to our Plan of Reorganization, the composition of the Board changed significantly. Upon emergence, the Board is now made up of seven directors, of which five have not previously served on the Board. The new directors have different backgrounds, experiences and perspectives from those individuals who previously served on the Board and, thus, may have different views on the issues that will determine the future of the Company. There is no guarantee that the new Board will pursue, or will pursue in the same manner, our current strategic plans. As a result, the future strategy and plans of the Company may differ materially from those of the past.

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

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

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

Funds associated with the Majority Second Lien Noteholders (as defined in the Plan of Reorganization) currently own a majority of our outstanding 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. Furthermore, pursuant to our Second Amended and Restated Certificate of Incorporation (the “Charter”), the Majority Second Lien Noteholders have the continuing right to nominate three members of the Board, subject to conditions on share ownership. In addition, our significant concentration of share ownership may adversely affect the trading price of our common stock because investors may perceive disadvantages in owning stock in companies with significant stockholders.

We do not expect to pay dividends in the near future.

We do not anticipate that cash dividends or other distributions will be paid with respect to our common stock in the foreseeable future. In addition, restrictive covenants in certain debt instruments to which we are, or may be, a party, may limit our ability to pay dividends or for us to receive dividends from our operating companies, any of which may negatively impact the trading price of our common stock.

Certain provisions of our Charter and our Bylaws may make it difficult for stockholders to change the composition of our Board and may discourage, delay or prevent a merger or acquisition that some stockholders may consider beneficial.

Certain provisions of our Charter and our Second Amended and Restated Bylaws (the “Bylaws”) may have the effect of delaying or preventing changes in control if our Board determines that such changes in control are not in the best interests of the Company and our stockholders. The provisions in our Charter and Bylaws include, among other things, those that:

- provide for a classified board of directors;
- authorize our Board to issue preferred stock and to determine the price and other terms, including preferences and voting rights, of those shares without stockholder approval;

- establish advance notice procedures for nominating directors or presenting matters at stockholder meetings; and
- limit the persons who may call special meetings of stockholders.

While these provisions have the effect of encouraging persons seeking to acquire control of the Company to negotiate with our Board, they could enable the Board to hinder or frustrate a transaction that some, or a majority, of the stockholders may believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors. These provisions may frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our Board, which is responsible for appointing the members of our management.

Oil prices and natural gas prices have declined substantially from historical highs and may remain depressed for the foreseeable future. Oil and natural gas prices are volatile; a sustained decrease in the price of oil or natural gas would adversely impact our business.

Our success depends on the market prices of oil and natural gas. These market prices tend to fluctuate significantly in response to factors beyond our control. The prices we receive for our crude oil production are based on global market conditions. The general pace of global economic growth, the continued instability in the Middle East and other oil and natural gas producing regions and actions of the Organization of Petroleum Exporting Countries, as well as other economic, political, and environmental factors will continue to affect world supply and prices. Domestic natural gas prices fluctuate significantly in response to numerous factors including U.S. economic conditions, weather patterns, other factors affecting demand such as substitute fuels, the impact of drilling levels on crude oil and natural gas supply, and the environmental and access issues that limit future drilling activities for the industry.

Natural gas and crude oil prices are extremely volatile. High and low spot prices for New York Mercantile Exchange ("NYMEX") West Texas Intermediate crude oil and NYMEX Henry Hub natural gas for were as follows:

	2016	
	High	Low
West Texas Intermediate crude oil price range per barrel	$54.06	$26.21
Henry Hub natural gas price range per MMBtu	3.23	1.70

Average oil and natural gas prices varied substantially during the past few years. Any actual or anticipated reduction in natural gas and crude oil prices may further depress the level of exploration, drilling and production activity. We expect that commodity prices will continue to fluctuate significantly in the future.

Changes in commodity prices significantly affect our capital resources, liquidity and expected operating results. These lower prices, coupled with the slow recovery in financial markets that has significantly limited and increased the cost of capital, have compelled most oil and natural gas producers, including us, to reduce the level of exploration, drilling and production activity. This will have a significant effect on our capital resources, liquidity and expected operating results. Any sustained reductions in oil and natural gas prices will directly affect our revenues and can indirectly impact expected production by changing the amount of funds available to us to reinvest in exploration and development activities. Further reductions in oil and natural gas prices could also reduce the quantities of reserves that are commercially recoverable. Additionally, further or continued declines in prices could result in additional non-cash charges to earnings due to impairment write-downs. Any such write down could have a material adverse effect on our results of operations in the period taken.

Our future revenues are dependent on the ability to successfully complete drilling activity.

Drilling and exploration are the main methods we utilize to replace our reserves. However, drilling and exploration operations may not result in any increases in reserves for various reasons. Exploration activities involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- reductions in oil and natural gas prices;
- inadequate capital resources;
- limitations in the market for oil and natural gas;
- lack of acceptable prospective acreage;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;

- unavailability or high cost of drilling rigs, equipment or labor;

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- title problems;
- compliance with governmental regulations;
- mechanical difficulties; and
- risks associated with horizontal drilling.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain.

In addition, while lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically, higher oil and natural gas prices generally increase the demand for drilling rigs, equipment and crews and can lead to shortages of, and increased costs for, such drilling equipment, services and personnel. Such shortages could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could adversely affect our ability to increase our reserves and production and reduce our revenues.

A sustained depression of oil and natural gas prices can continue to affect our ability to obtain funding on acceptable terms. This may hinder or prevent us from meeting our future capital needs.

We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on more expensive or otherwise unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

Our new common stock is listed on the OTCQX marketplace and is held by a small group of investors.

The lack of market and float of our stock can have an adverse effect on the market liquidity of our common stock and, as a result, the market price for our common stock could become more volatile. If we are unable to become re-listed on a national securities exchange and increase the market value per share of our common stock, it may be difficult to attract the interest of analysts, institutional investors, investment funds and brokers.

There may be future sales or other dilution of our equity, which may adversely affect the market price of our common stock.

We are not restricted from issuing additional common stock, including securities that are convertible into or exchangeable for, or that represent a right to receive, common stock. Any issuance of additional shares of our common stock or convertible securities, including outstanding options, or otherwise will dilute the ownership interest of our common stockholders. Sales of a substantial number of shares of our common stock or other equity-related securities in the public market could depress the market price of our common stock and impair our ability to raise capital through the sale of additional equity securities. We cannot predict the effect that future sales of our common stock or other equity-related securities would have on the market price of our common stock.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material.

The proved oil and natural gas reserve information included in this report are estimates. These estimates are based on reports prepared by NSAI and RSC, our independent reserve engineers, and were calculated using the unweighted average of first-day-of-the-month oil and natural gas prices in 2016. The prices we receive for our production may be lower than those upon which our reserve estimates are based. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing wells;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and natural gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and natural gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material. The discounted future net cash flows included in this document should not be considered as the current market value of the estimated oil and natural gas reserves attributable to our properties. As required by the SEC, the standardized measure of discounted future net cash flows from proved reserves are generally based on 12-month average prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, which is required by the SEC to be used to calculate discounted future net cash flows for reporting purposes, and which we use in calculating our PV-10, is not necessarily 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.

Our operations are subject to governmental risks that may impact our operations.

Our operations have been, and at times in the future may be, affected by political developments and are subject to complex federal, state, tribal, local and other laws and regulations such as restrictions on production, permitting and changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies or price gathering-rate controls. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, tribal and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws, including tax laws, and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

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

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, regional, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of permits, including drilling permits, before conducting regulated activities; plugging and abandonment and site reclamation requirements; the restriction of types, quantities and concentration of materials that can be released into the environment; limiting or prohibiting drilling activities on certain lands lying within wilderness, wetlands and other protected areas, the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition 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 as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liabilities for the removal or remediation of previously released materials or property contamination. Failure to comply with environmental laws and regulations may result in the assessment of civil and criminal fines and penalties, the revocation of permits or the issuance of injunctions restricting or prohibiting our operations in certain areas. Moreover, private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. Changes in environmental laws and regulations occur frequently and the clear trend is to place increasingly stringent limitations on activities that may affect the environment. Any changes in legal requirements related to the protection of the environment could result in more stringent or costly well drilling, construction, completion or water management activities, or waste control, handling, storage, transport, disposal or cleanup requirements. Such changes could also require us to make significant expenditures to attain and maintain compliance, and also have the potential to reduce demand for the oil and gas we produce and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as government reviews of such activity could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and 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. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. For example, the EPA has taken the following actions and issued: guidance under the SDWA for hydraulic fracturing activities involving the use of diesel fuel; final regulations under the federal Clean Air Act governing performance standards, including standards for the capture of volatile organic compounds and methane emissions released during hydraulic fracturing; an advanced notice of proposed rulemaking in March 2014 under the Toxic Substances Control Act that would require companies to disclose information regarding the chemicals used in hydraulic fracturing; and finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming has temporarily stayed implementation of this rule. A final decision has not yet been issued.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. The EPA has not proposed to take any action in response to the report's findings.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Louisiana and Texas, 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. There has also been increased public scrutiny of seismic events in areas where hydraulic fracturing of wastewater disposal activities occur. Moreover, some states and local governments have enacted laws or regulations limiting hydraulic fracturing within their borders or prohibiting the activity altogether. In the event that 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.

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

Certain scientific studies have found that emissions of carbon dioxide, methane and other "greenhouse gases" are contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA determined that greenhouse gases present an endangerment to public health and the environment and has issued regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from a variety of sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis, including greenhouse gas emissions from completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. These changes to EPA's GHG emissions reporting rule could result in increased compliance costs. Also, in June 2016, the EPA finalized rules that establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The BLM finalized similar rules in November 2016 that limit methane emissions from new and existing oil and gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. . However, both the U.S. House of Representatives and the Senate have introduced resolutions seeking to repeal the BLM methane rules under the Congressional Review Act and future implementation of the BLM methane rules is uncertain. However, the BLM and the EPA methane rules have substantial similarities with respect to pollution control equipment and LDAR requirements. Compliance with rules to control methane emissions will likely require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks, and the increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third party contractors to assist with and verify compliance. These new and proposed rules could result in increased compliance costs on our operations.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and many states have established greenhouse gas cap and trade programs. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce, which in turn could have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases 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. Such climatic events could have an adverse effect on our financial condition and results of operations.

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

The Predecessor Company incurred operating losses of $494.5 million and $354.8 million, for the years ended December 31, 2015 and 2014, respectively. Post emergence from bankruptcy in 2016, the Successor company had an operating loss of $2.6 million. Our development 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.

The enactment of derivatives legislation 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.

The Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act") enacted in 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission ("CFTC") and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

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

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from such margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures; therefore reducing our ability to execute hedges to reduce risk and protect cash flow.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and 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, or reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations on us is uncertain.

Certain U.S. federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted into law 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. Such legislative 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. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on the Company's financial position, results of operations and cash flows.

Our use of oil and natural gas price hedging contracts may limit future revenues from price increases and result in significant fluctuations in our net income.

We have historically used hedging transactions with respect to a portion of our oil and natural gas production to achieve more predictable cash flow and to reduce our exposure to price fluctuations. While the use of hedging transactions limits the downside risk of price declines, their use may also limit future revenues from price increases. We had no hedge settlements in 2016 and did not have any hedge contracts at December 31, 2016.

We account for our oil and natural gas derivatives using fair value accounting standards. Each derivative is recorded on the balance sheet as an asset or liability at its fair value. Additionally, changes in a derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is executed. We have elected not to apply hedge accounting treatment to our swap and call derivative contracts and, as such, all changes in the fair value of these instruments are recognized in earnings. Our fixed price physical contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment.

In the future, we will continue to be exposed to volatility in earnings resulting from changes in the fair value of our derivative instruments. See Note 10-"Derivative Activities" in the Notes to Consolidated Financial Statements in "Item 8—Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Oil and natural gas prices are volatile. All of our crude oil hedging contracts expired in 2015. If we choose not to or are unable to replace our hedges, our cash flows from operations will be subjected to increased volatility.

We have historically entered into hedging transactions for our oil and natural gas production revenues to reduce our exposure to fluctuations in the price of oil and natural gas. All of our crude oil hedging contracts expired in 2015. As a result, more of our future production will be sold at market prices, exposing us to the fluctuations in the price of oil and natural gas, unless we enter into additional hedging transactions. We may choose not to or be unable to replace our hedges, which will subject our cash flows from operations to increased volatility.

Because our operations require significant capital expenditures, we may not have the funds available to replace reserves, maintain production or maintain interests in our properties.

We must make a substantial amount of capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. Historically, we have paid for these expenditures with cash from operating activities, proceeds from debt and equity financings and asset sales. Our revenues or cash flows could be reduced because of lower oil and natural gas prices or for other reasons. If our revenues or cash flows decrease, we may not have the funds available to replace reserves or maintain production at current levels. If this occurs, our production will decline over time. Other sources of financing may not be available to us if our cash flows from operations are not sufficient to fund our capital expenditure requirements. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on more expensive or otherwise unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. Where we are not the majority owner or operator of an oil and natural gas property, we may have no control over the timing or amount of capital expenditures associated with the particular property. If we cannot fund such capital expenditures, our interests in some properties may be reduced or forfeited.

If we are unable to replace reserves, we may not be able to sustain production at present levels.

Our future success depends largely upon our ability to find, acquire or develop additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves will decline over time. At December 31, 2016, 85% of our total estimated proved reserves by volume were undeveloped. By their nature, estimates of proved undeveloped reserves and timing of their production are less certain particularly because we may chose not to develop such reserves on anticipated schedules in future adverse oil or natural gas price environments. Recovery of such reserves will require significant capital expenditures and successful drilling operations. The lack of availability of sufficient capital to fund such future operations could materially hinder or delay our replacement of produced reserves. We may not be able to successfully find and produce reserves economically in the future. In addition, we may not be able to acquire proved reserves at acceptable costs.

We may incur substantial impairment writedowns.

If management’s estimates of the recoverable proved reserves on a property are revised downward or if oil and natural gas prices decline, we may be required to record additional non-cash impairment writedowns in the future, which would result in a negative impact to our financial position. Furthermore, any sustained decline in oil and natural gas prices may require us to make further impairments. Prior to emerging from bankruptcy we accounted for our Oil and Gas properties using the Successful Efforts Method of Accounting. We reviewed our proved oil and natural gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management’s estimates of future oil and natural gas prices to the estimated future production of oil and natural gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers’ estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units’ estimated reserves, future cash flows and fair value. For the years ended December 31, 2015, we recorded impairment related to oil and natural gas properties of $452.0 million. The decline in oil and natural gas prices precipitated the loss of estimated proved reserves for our oil and natural gas producing properties. Additionally, the prospect of lower future prices raised substantial doubt about our ability to continue as a going concern and consequently all estimated proved undeveloped reserves were excluded from our estimated total proved reserves as of December 31, 2015 and the carrying cost of the related undeveloped leasehold was impaired.

Upon emerging from bankruptcy we implemented Fresh Start Reporting and changed to the Full Cost Method of accounting for our Oil and Natural Gas Properties. The Full Cost Method requires a ceiling test be performed each quarter to determine impairment. The reserve value basis used in the Ceiling Test is the SEC calculated reserves. The SEC value of reserves utilizes a look back at the last twelve month commodity prices. The Ceiling Test performed on December 31, 2016 resulted in an impairment of $2.5 million.

A majority of our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Essentially all of our estimated proved reserves at December 31, 2016 were associated with our Louisiana, Texas and Mississippi properties which include the Haynesville Shale and TMS Trend. Accordingly, if the level of production from these properties substantially declines or is otherwise subject to a disruption in our operations resulting from operational problems, government intervention (including potential regulation or limitation of the use of high pressure fracture stimulation techniques in these formations) or natural disasters, it could have a material adverse effect on our overall production level and our revenue.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. For example, Chesapeake operates certain properties in the Haynesville Shale Trend. As of December 31, 2016, approximately 73% of our reserves and approximately 40% of our sales volumes were attributable to non-operated properties. We have less ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them versus those fields in which we are the operator. Our dependence on the operator and other working interest owners for these projects and our reduced influence or ability to control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital and lead to unexpected future costs.

Our ability to sell natural gas and receive market prices for our natural gas may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

We operate primarily in (i) Northwest Louisiana and East Texas, which includes the Haynesville Shale Trend and (ii) Southwest Mississippi and Southeast Louisiana which includes the TMS Trend. A number of companies are currently operating in the Haynesville Shale Trend. If drilling in these areas continues to be successful, the amount of natural gas being produced could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in this region. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for Northwest Louisiana and East Texas may not occur or may be substantially delayed for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our natural gas to interstate pipelines. In such an event, we might have to shut in our wells awaiting a pipeline connection or capacity or sell natural gas production at significantly lower prices than those quoted on NYMEX or that we currently project, which would adversely affect our results of operations.

A portion of our oil and natural gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, the interruption could temporarily adversely affect our cash flow.

We may be unable to identify liabilities associated with the properties that we acquire or obtain protection from sellers against them.

The acquisition of properties requires us to assess a number of factors, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well, facility or pipeline. We cannot necessarily observe structural and environmental problems, such as pipeline corrosion or subsurface groundwater contamination, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities relating to the acquired assets and indemnities are unlikely to cover liabilities relating to the time periods after closing. We may be required to assume any risk relating to the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. The incurrence of an unexpected liability could have a material adverse effect on our financial position and results of operations.

Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. The loss of, or material nonpayment or nonperformance by, any one or more of these customers could materially adversely affect our financial condition, results of operations and cash flows.

Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. Revenues from the largest of these sources as a percent of oil and natural gas revenues for the year ended December 31, 2016, and 2015 were 87%, and 74%, respectively. Some of our customers may have material financial and liquidity issues or may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better-capitalized companies. Any material nonpayment or nonperformance by any of our key customers could have a material adverse effect on our financial condition, results of operations and cash flows. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our revenue.

Customer credit risks could result in losses.

Our exposure to non-payment or non-performance by our customers and counterparties presents a credit risk. Generally, non-payment or non-performance results from a customer's or counterparty's inability to satisfy obligations. We monitor the creditworthiness of our customers and counterparties and established credit limits according to our credit policies and guidelines, but cannot assure that any losses will be consistent with our expectations. Furthermore, the concentration of our customers in the energy industry may impact our overall exposure to credit risk as customers may be similarly affected by prolonged changes in economic and industry conditions. The revenues compared to our total oil and natural gas revenues from the top purchasers for the years ended December 31, 2016 and 2015 are as follows:

	Year Ended December 31, 2016	2015
Genesis Crude Oil LP	44 %	26 %
Sunoco, Inc.	30 %	17 %
Occidental Energy MA	13 %	— %
BP Energy Company	— %	31 %

Competition in the oil and natural gas industry is intense, and we are smaller and have a more limited operating history than some of our competitors.

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to operate and to develop these properties. Some of our competitors have substantially greater financial and other resources than us. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for oil and natural gas properties and may be able to define, evaluate, bid for and acquire a greater number of properties than we can. Our ability to acquire additional properties and develop new and existing properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Our success depends on our management team and other key personnel, the loss of any of whom could disrupt our business operations.

Our success will depend on our ability to retain and attract experienced engineers, geoscientists and other professional staff. We depend to a large extent on the efforts, technical expertise and continued employment of these personnel and members of our management team. If a significant number of them resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

The oil and natural gas exploration and production business involves many uncertainties, economic risks and operating risks that can prevent us from realizing profits and can cause substantial losses.

The nature of the oil and natural gas exploration and production business involves certain operating hazards such as:

- well blowouts;
- cratering;
- explosions;
- uncontrollable flows of oil, natural gas, brine or well fluids;
- fires;
- formations with abnormal pressures;
- shortages of, or delays in, obtaining water for hydraulic fracturing operations;
- environmental hazards such as crude oil spills;
- natural gas leaks;
- pipeline and tank ruptures;
- unauthorized discharges of brine, well stimulation and completion fluids or toxic gases into the environment;
- encountering naturally occurring radioactive materials;
- other pollution; and
- other hazards and risks.

Any of these operating hazards could result in substantial losses to us. As a result, substantial liabilities to third parties or governmental entities may be incurred. The payment of these amounts could reduce or eliminate the funds available for exploration, development or acquisitions. These reductions in funds could result in a loss of our properties.
Additionally, some of our oil and natural gas operations are located in areas that are subject to weather disturbances such as hurricanes. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production.
We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.
We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position and results of operations.
There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future. A loss in connection with our oil and natural gas properties could have a materially adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies cover only a portion of any such loss.
We may be unable to maintain compliance with the financial maintenance or other covenants in the Exit Credit Facility, which could result in an event of default under the Exit Credit Facility that, if not cured or waived, would have a material adverse effect on our business, financial condition and results of operations.
Under the Exit Credit Facility, the Company and the Subsidiary are required to maintain certain financial covenants including the maintenance of (i) a Total Proved Asset Coverage Ratio (as defined in the Exit Credit Agreement) not to be less than 1.5 to 1.0 initially, and increasing to 2.0 to 1.0 or after December 31, 2018, (ii) Secured Debt Asset Coverage Ratio (as defined in the Exit Credit Agreement) not to be less than 1.10 to 1.00 initially, and increasing to 1.35 to 1.00 and 1.50 to 1.00 after March 31, 2017 and September 30, 2017, respectively, in the case of clauses (i) and (ii), to be determined as of January 1 and July 1 each year and as of the date of any Material Acquisition (as defined in the Exit Credit Agreement) or Material Disposition (as defined in the Exit Credit Agreement), (iii) commencing with the fiscal quarter ending March 31, 2018, a ratio of Debt (as defined in the Exit Credit Agreement) as of the end of each fiscal quarter to EBITDAX for the twelve months ending on the last day of such fiscal quarter, not to exceed 4.00 to 1.00, (iv) limitations on Consolidated Cash Balance (as defined in the Exit Credit Agreement), (v) limitations on general and administrative expenses and (vi) minimum liquidity requirements.
The Exit Credit Facility also contains certain covenants which, among other things, and subject to certain exceptions, restrict the Company’s and certain of its subsidiaries’ ability to incur additional debt or liens, pay dividends, repurchase equity interests, prepay other indebtedness, sell, transfer, lease or dispose of assets, and make investments in or merge with another company.
If the Company were to violate any of the covenants under the Exit Credit Facility and were unable to obtain a waiver, it would be considered a default after the expiration of any applicable grace period. If the Company were in default under the Exit Credit Facility, then the lenders thereunder may exercise remedies in accordance with the terms thereof, including declaring all outstanding borrowings immediately due and payable. This could adversely affect our operations and our ability to satisfy our obligations as they come due.

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Restrictive covenants in our Exit Credit Facility may restrict our ability to pursue our business strategies.
The Exit Credit Facility limits our ability, among other things, to:
- incur additional indebtedness;
- incur additional liens;
- pay dividends or make other distributions;
- make investments;
- sell or discount of receivables;
- enter into mergers;
- sell properties;
- terminate swap agreements;
- enter into transactions with affiliates;
- maintain gas imbalances;
- enter into take-or-pay contracts or make other prepayments;
- enter into swap agreements; and
- make capital expenditures.

The Exit Credit Facility also requires us to comply with certain financial maintenance covenants as discussed above. A breach of any of these restrictive covenants could result in a default under the in Exit Credit Facility. If a default occurs, the lenders may elect to declare all borrowings thereunder outstanding, together with accrued interest and other fees, to be immediately due and payable. 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.
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.
As of the date of filing this Annual Report, we have outstanding (i) costless warrants granted to the New 2L Notes Purchasers representing 2.5 million shares of our common stock, (ii) out-of-the-money 1.3 million warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million and (iii) 1.9 million restricted stock awards. 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 warrants in the future.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

A discussion of our current legal proceedings is set forth in Note 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements in “Item 8—Financial Statements and Supplementary Data” of this Annual Report on Form 10-K.
For a discussion of our Chapter 11 Cases, please see “Items 1. and 2. Business and Properties” under the headings “Voluntary Reorganization under Chapter 11 of the Bankruptcy Code,” “Commitment Letter” and “Plan of Reorganization” of this Annual Report on Form 10-K.

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Price of Our Common Stock

The Predecessor Company's common stock was traded on the New York Stock Exchange (“NYSE”) under the symbol “GDP” throughout 2015. The New York Stock Exchange (the "NYSE") delisted our common stock due to our abnormally low trading price in January 2016. Our common stock subsequently traded on the OTC Pink marketplace under the symbol "GDPMQ" until its cancellation on October 12, 2016, pursuant to the bankruptcy court's confirmation of our Plan of Reorganization. Upon our bankruptcy emergence, we issued 6.8 million shares of our new common stock, and commenced trading on the OTCQX marketplace under the symbol "GDPP" on December 8, 2016. At February 9, 2016, the number of holders of record of our common stock was 709 and 9,108,826 shares were outstanding. High and low sales prices for our common stock for each quarter during 2016 and 2015 were as follows:

	2016		2015	
	High	Low	High	Low
First Quarter	$0.28	$0.05	$4.76	$2.35
Second Quarter	0.08	0.02	4.45	1.55
Third Quarter	0.05	0.01	1.86	0.54
Fourth Quarter (Successor Company December, 2016)	14.00	10.75	0.90	0.20

The over-the-counter market quotations for 2016 reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not necessarily represent actual transactions.

Dividends

We do not anticipate declaring any dividends on the Successor Company common stock in the foreseeable future.

Issuer Repurchases of Equity Securities

No private or open market repurchases of our common stock were made by or on our behalf or any that of any affiliated purchaser for the year ended December 31, 2016.

For information on securities authorized for issuance under our equity compensation plans, see “Item 12—Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.”

Unregistered Sales of Equity Securities

None that have not been previously reported by us on a Current Report on Form 8-K.

Performance

The following performance graph and related information shall not be deemed “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the company specifically incorporates it by reference into such filing.

The following graph compares the cumulative five-year total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 Index and the Russell 2000 Index. An investment of $100 is assumed to have been made in our common stock and the indexes on December 31, 2010 and its relative performance is tracked through December 31, 2016.

Item 6. Selected Financial Data

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this item.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read together with the Consolidated Financial Statements and the Notes to Consolidated Financial Statements, which are included in this Annual Report on Form 10-K in "Item 8—Financial Statements and Supplementary Data", and the information set forth in "Item 1A—Risk Factors".

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of properties primarily in (i) Northwest Louisiana and East Texas, which includes the Haynesville Shale Trend (ii) Southwest Mississippi and Southeast Louisiana, which includes the Tuscaloosa Marine Shale Trend (“TMS”), and (iii) South Texas, which includes the Eagle Ford Shale Trend.

We seek to increase shareholder value by growing our oil and natural gas reserves, production, revenues and cash flow from operating activities (“operating cash flow”). In our opinion, on a long term basis, growth in oil and natural gas reserves, cash flow and production on a cost-effective basis are the most important indicators of performance success for an independent oil and natural gas company.

Management strives to increase our oil and natural gas reserves, production and cash flow through exploration and development activities. We develop an annual capital expenditure budget, which is reviewed and approved by our board of directors on a quarterly basis and revised throughout the year as circumstances warrant. We take into consideration our projected operating cash flow and externally available sources of financing, such as bank debt, asset divestures, issuance of debt and equity securities and strategic joint-ventures, when establishing our capital expenditure budget.

We place primary emphasis on our operating cash flow in managing our business. Management considers operating cash flow a more important indicator of our financial success than other traditional performance measures such as net income because operating cash flow considers only the cash expenses incurred during the period and excludes the non-cash impact of unrealized hedging gains (losses), non-cash general and administrative expenses and impairments.

Our revenues and operating cash flow depend on the successful development of our inventory of capital projects with available capital, the volume and timing of our production, as well as commodity prices for oil and natural gas. Such pricing factors are largely beyond our control; however, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Key Developments

The following general economic developments and corporate actions in 2015 and 2016 had and may continue to have a significant impact on our financial position and results of operations:

The Current, Sustained Low Commodity Price Environment

Beginning in the second half of 2014, commodity prices, particularly crude oil, began to decline sharply. The decline became precipitous late in the fourth quarter of 2014 and into 2015. Crude oil prices declined from a high of over $105 per barrel in June 2014 to less than $27 per barrel in February 2016. Natural gas prices faced similar downward pressure during the same period, dropping below $1.70 per MMBtu in December 2015. As an exploration and production company with interests in unconventional oil and natural gas shale properties that require large investments of capital to develop, the significant magnitude of this price decline has had a particularly material and adverse impact on our results of operations and led to substantial changes in our operating and drilling programs.

In response to the decline in commodity prices, we focused on managing our balance sheet to reduce leverage and preserve liquidity during this extended low commodity price environment. Specifically, we took the following steps in 2016 and 2015 to mitigate the effects of lower crude oil prices on our operations and conserve capital:

- Reduced our capital expenditures for 2016 to $6.3 million as compared to $85.5 million in 2015;
- Generated savings by negotiating cost reductions from service providers in both 2015 and 2016;
- Froze salaries at 2014 levels initially and subsequently materially reduced the salaries of our management team;
- Reduced our staff headcount over 50% from year-end 2014 levels;
- Reduced discretionary expenditures.

Despite having taken these measures, with the continued low commodity price environment, our cash flow from operations substantially declined and the stock price of our common stock declined significantly. On January 13, 2016, the NYSE formally commenced delisting procedures for our common stock due to our abnormally low trading price. On January 21, 2016, the NYSE filed a Form 25 with the SEC, notifying us of the removal of our common stock from listing.

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In addition to the previously mentioned measures taken to reduce costs and increase liquidity, in January 2016, we launched a comprehensive plan (the "Recapitalization Plan") to exchange our notes and preferred stock for common stock in an effort to reduce our dividend and debt service cost. The Recapitalization Plan was unsuccessful and the financial condition of the Company became unsustainable.

Chapter 11 Bankruptcy

On April 15, 2016 (the "Petition Date"), we and our subsidiary Goodrich Petroleum Company, L.L.C. filed voluntary Bankruptcy petitions seeking relief under Chapter 11 of Title 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas, Houston Division, to pursue a Chapter 11 plan of reorganization. We filed a motion with the Bankruptcy Court seeking joint administration of the Chapter 11 Cases under the caption In re Goodrich Petroleum Corporation, et al. (Case No. 16-31975). The Chapter 11 Cases constituted an event of default that accelerated our obligations under all our outstanding debt instruments. The agreements governing our debt instruments at the time provided that as a result of the Bankruptcy Petitions, the principal and interest due thereunder was immediately due and payable. However, any efforts to enforce such payment obligations under the debt instruments were automatically stayed as a result of the Chapter 11 Cases, and the creditors' rights of enforcement in respect of the debt instruments was subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. We subsequently operated the company as a debtor-in-possession.

We received Bankruptcy Court confirmation of our joint plan of reorganization on September 28, 2016 and subsequently emerged from bankruptcy on October 12, 2016. Although we are no longer a debtor-in-possession, we were a debtor-in-possession through October 12, 2016. As such, aspects of our bankruptcy proceedings and related matters are described below in order to provide context and explain a part of our financial condition and results of operations for the period presented. We are accounting for the bankruptcy in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 852, "Reorganizations". We filed a series of first day motions with the Bankruptcy Court that allowed us to continue to conduct business without interruption. These motions are designed primarily to minimize the impact on our operations, customers and employees.

On April 18, 2016, the Bankruptcy Court issued certain additional interim and final orders with respect to our first-day motions and other operating motions that allowed us to operate their businesses in the ordinary course. Subject to certain exceptions under the Bankruptcy Code, the filing of the Bankruptcy Petitions automatically enjoined, or stayed, the continuation of any judicial or administrative proceedings or other actions against the us or their property to recover, collect or secure a claim arising prior to the filing of the Bankruptcy Petitions. Thus, for example, most creditor actions to obtain possession of property from us, or to create, perfect or enforce any lien against the our properties, or to collect on monies owed or otherwise exercise rights or remedies with respect to a pre-petition claim were enjoined.

During the Chapter 11 Cases, we conducted normal business activities and were authorized to continue to pay and have paid (subject to limitations applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders, critical vendors and other third parties, such as royalty holders and partners.

On July 25, 2016 we entered into and filed a motion with the Bankruptcy Court to approve a commitment letter (the "Commitment Letter") with a group of investors for the new issuance of 13.50% Convertible Senior Secured Second Lien Notes in the initial aggregate principal amount of $40.0 million (the "Convertible Second Lien Notes"). The Bankruptcy Court approved the motion on August 4, 2016 which allowed us to submit a revised plan of organization to the Bankruptcy Court.

Emergence from Bankruptcy

The Company's joint plan of reorganization (the "Plan of Reorganization") was confirmed by the Bankruptcy Court on September 28, 2016 and we emerged from bankruptcy on October 12, 2016 (the "Effective Date").

On October 12, 2016, we entered into an Exit Credit Agreement (including all amendments, the "Exit Credit Facility") by which various lenders have agreed to provide us with a $20.0 million senior secured term loan credit facility, with an outstanding principal amount of $20.0 million. The Commitment Letter provided for the issuance of $40.0 million in Convertible Second Lien Notes that mature on the later of August 30, 2019 or six months after the maturity of the

Exit Credit Agreement. A total of $20.0 million in proceeds from the issuance of the Convertible Second Lien Notes were used to repay amounts outstanding under the existing Second Amended and Restated Credit Agreement (including all amendments, the “Senior Credit Facility”) and $20.0 million in proceeds will be used to fund the Company’s Haynesville Shale Trend drilling program.

Plan of Reorganization

The significant features of the Plan of Reorganization confirmed by the Bankruptcy Court are as follows:

1. Each holder of an allowed priority claim (other than a priority tax claim or administrative claim) received either: (a) cash equal to the full allowed amount of its claim or (b) such other treatment as may otherwise be agreed to by such holder, the Debtors, the holders of at least 50% in principal amount of the Second Lien Notes (the “Majority Consenting Noteholders”), and the purchasers of the new Convertible Second Lien Notes (“New 2L Notes Purchasers”);

2. Each holder of a secured claim (other than a priority tax claim, Senior Credit Facility claim, or Second Lien Notes claim) received, at the Debtors’ election and with the consent of the Majority Consenting Noteholders, either: (a) cash equal to the full allowed amount of its claim, (b) reinstatement of such holder’s claim, (c) the return or abandonment of the collateral securing such claim to such holder, or (d) such other treatment as may otherwise be agreed to by such holder, the Debtors, the Majority Consenting Noteholders, and the New 2L Notes Purchasers;

3. The Senior Credit Facility claims were paid cash in an amount sufficient to reduce the Senior Credit Facility claims to a balance of $20.0 million while the remaining $20.0 million owed was refinanced into a new senior secured term loan credit facility;

4. The Second Lien Notes claims were deemed allowed in the aggregate amount of $175.0 million of principal plus accrued and unpaid interest through the Petition Date. Except to the extent a holder of a Second Lien Note claim agreed in writing to less favorable treatment, in full and final satisfaction, settlement, release, and discharge of, and in exchange for, each Second Lien Notes claim, each holder of a Second Lien Notes claim received their pro rata share of 98% of the new equity interests in the reorganized company (the “New Equity Interests”), subject to dilution on account of (i) the management incentive plan, (ii) the potential conversion of the Convertible Second Lien Notes, (iii) the warrants granted to the New 2L Notes Purchasers, and (iv) the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million;

5. Holders of unsecured notes claims received, pro rata with holders of other general unsecured claims, their pro rata share of the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million; plus its pro rata share of 2% of the New Equity Interests that are subject to dilution on account of (i) the management incentive plan, (ii) the potential conversion of the Convertible Second Lien Notes, (iii) the warrants granted to the New 2L Notes Purchasers, and (iv) the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal of $230.0 million;

6. Holders of allowed general unsecured claims had the option to elect on their ballot to (a) receive, pro rata with holders of unsecured notes claims, its pro rata share of the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million; plus its pro rata share of 2% of the New Equity Interests that are subject to dilution on account of (i) the management incentive plan, (ii) the potential conversion of the Convertible Second Lien Notes, (iii) the warrants granted to the New 2L Notes Purchasers, and (iv) the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million, or (b) treat its allowed general unsecured claim as a convenience class claim by releasing any claims in excess of $10,000;

7. Holders of convenience class claims received either: (a) cash equal to the full allowed amount of such holder's claim or (b) such lesser treatment as may otherwise be agreed to by such holder, the Debtors, the Majority Consenting Noteholders and the New 2L Notes Purchasers;

8. Equity interests in the Subsidiary were canceled and extinguished without further notice to, approval of, or action by any entity, and each holder of an equity interest in the Subsidiary did not receive any distribution or retain any property on account of such equity interest in the Subsidiary. Equity interests in the Company were canceled and extinguished without further notice to, approval of, or action by any entity, and each holder of an equity interest in the Company did not receive any distribution or retain any property on account of such equity interest in the Company.

Fresh Start and Full Cost Accounting

Upon our emergence from bankruptcy, we adopted Fresh Start Accounting in accordance with the requirements of FASB ASC 852, "Reorganizations". This resulted in our becoming a new entity for financial reporting purposes. At that time, our assets and liabilities were recorded at their fair values as of the Effective Date. The effects of the Plan of Reorganization and our application of fresh start accounting are reflected in our consolidated financial statements as of December 31, 2016. The related adjustments were recorded in our consolidated statement of operations as reorganization items for the year to date period ending October 12, 2016.

The application of fresh start accounting and the effects of the implementation of our Plan of Reorganization resulted in our Consolidated Financial Statements on or after October 12, 2016 not being comparable with the Consolidated Financial Statements prior to that date. Our financial results for future periods following our application of fresh start accounting will be different from historical trends and the differences may be material.

All references made to "Successor" or "Successor Company" relate to the Company on and subsequent to the Effective Date. References to the “Successor 2016 Period” relate to the period from October 13, 2016 to December 31, 2016. References to "Predecessor" or “Predecessor Company” refer to the Company prior to the Effective Date. References to the “Predecessor 2016 Period” relate to the period from January 1, 2016 to October 12, 2016. The consolidated financial statements of the Successor have been prepared with the assumption that the Company will continue as a going concern and contemplate the realization of assets and the satisfaction of liabilities in the normal course of business. Additional information pertaining to our adoption, application, and effects of fresh start accounting is contained in Note 2 to these Consolidated Financial Statements.

On October 12, 2016, to better reflect the true economics of our exploration and development of oil and gas reserves, we transitioned from the Successful Efforts Method of Accounting for Oil and Gas Activities to the Full Cost Method.

Financial Statement Classification of Liabilities Subject to Compromise

The Predecessor financial statements included amounts classified as liabilities subject to compromise, the majority of which were equitized on October 12, 2016, upon our emergence from bankruptcy. See Note 3 to these Consolidated Financial Statements for additional information.
2016 Financial and Operating Results included:

- We emerged from bankruptcy as a reorganized Company with $30 million in equity and $60 million in debt;
- We ended the year with 303 Bcfe of proved oil and natural gas reserves;
- We ended the year with $36.9 million in cash;
- We restarted our drilling program by participating in two successful wells in the Haynesville Shale Trend;
- We realized cash proceeds of $23.8 million from the issuance of 2.3 million share of common stock in a private placement.

Tuscaloosa Marine Shale Trend

We held approximately 215,000 gross (156,000 net) acres in the TMS as of December 31, 2016. During 2016, we did not conduct any drilling operations in the TMS; however, we had 2 gross (1.7 net) wells drilled in 2015 still waiting on completion. Our net production volumes from our TMS wells represented approximately 35% of our total equivalent production on a Mcfe basis and approximately 99% of our total oil production for the year ended December 31, 2016. During 2016, we spent $1.5 million in the TMS, which included $0.2 million for leasehold costs.

Haynesville Shale Trend

Our relatively low risk development acreage in this trend is primarily centered in and around Angelina and Nacogdoches counties, Texas and DeSoto and Caddo parishes, Louisiana. We hold approximately 48,000 gross (24,000 net) acres as of December 31, 2016 producing from or prospective for the Haynesville Shale. We drilled 2 gross (0.4 net) wells in 2016 spending $4.1 million of which $0.3 million was leasehold cost. Our net production volumes from our Haynesville Shale Trend wells represented approximately 62% of our total equivalent production on a Mcfe basis for 2016.

Eagle Ford Shale Trend

We sold our Eagle Ford Shale Trend proved reserves and a portion of the associated leasehold on September 4, 2015. We have retained as of December 31, 2016 approximately 14,000 net acres of undeveloped leasehold in Frio County, Texas, which is prospective for future development or sale.

Results of Operations

In addition to adopting Fresh Start Accounting , the Successor also adopted the Full Cost Method of Accounting as of October 12, 2016. Prior to October 12, 2016, the Predecessor used the Successful Efforts Method of Accounting. The results of operations of the Successor and the Predecessor are not generally comparable in 2016 nor are they individually comparable with prior periods. We believe however, that production volumes, oil and natural gas revenues, lease operating expenses and production and other taxes are generally comparable consequently, unless otherwise indicated the tables and discussions below include pro forma results of the Predecessor and the Successor together for the periods in 2016 for these operational items. We believe this pro forma presentation gives the reader a better understanding of our operational results in 2016.

The Predecessor 2016 Period results of operation reflects the period from January 1, 2016 to October 12, 2016. The Net income of $369.9 million was primarily the result of the $399.4 million gain on the implementation of the Plan of Reorganization. Under the Plan of Reorganization, we experienced gains from the cancellation of our then outstanding Second Lien Notes and unsecured senior notes with the related accrued interest offset by the expenses incurred in the reorganization and the fair value of the Successor Company equity received by the senior note holders pursuant to the Plan of Reorganization.

The Successor 2016 Period results of operations reflects the period from October 13, 2016 to December 31, 2016. The net loss of $4.3 is primarily the result of the $2.5 million impairment expense recorded on our oil and gas properties. The Successor adopted the Full Cost Method of Accounting which requires a quarterly Full Cost Ceiling Test. The fair value assigned to the Successor's oil and gas assets upon adoption of Fresh Start Accounting was based upon a market participant fair value while the Full Cost Ceiling Test is based upon the value of oil and gas properties using SEC reserve pricing. The SEC pricing reflects a look back of 12 months and as of December 31, 2016, oil and gas prices were lower than the prospective prices used by a market participant fair value resulting in a Full Cost Ceiling write down.

The following table reflects our summary operating information for the periods presented in thousands except for price and volume data. Because of normal production declines, increased or decreased drilling activity and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as indicative of future results.

	October 13, to December 31, 2016	January 1, 2016 to October 12, 2016	Year Ended December 31,			
	Successor	Predecessor	Pro forma 2016	Predecessor 2015	Variance	
Summary Operating Information:						
Revenues:						
Natural gas	$ 2,327	$ 5,817	$8,144	$ 14,282	$(6,138)	(43)%
Oil and condensate	4,210	15,210	19,420	64,795	(45,375)	(70)%
Natural gas, oil and condensate	6,537	21,027	27,564	79,077	(51,513)	(65)%
Net Production:						
Natural gas (Mmcf)	1,198	4,357	5,555	7,984	(2,429)	(30)%
Oil and condensate (MBbls)	88	388	476	1,336	(860)	(64)%
Total (Mmcfe)	1,723	6,687	8,410	16,000	(7,590)	(47)%
Average daily production (Mcfe/d)	21,538	23,381	22,979	43,836	(20,857)	(48)%
Average Realized Sales Price Per Unit:						
Natural gas (per Mcf)	$ 1.94	$ 1.34	$1.47	$ 1.79	$(0.32)	(18)%
Oil and condensate (per Bbl)	$ 47.84	$ 39.20	$40.80	$ 48.50	$(7.70)	(16)%
Oil and condensate (per Bbl) including the effect of realized gains/losses on derivatives	$ 47.84	$ 39.20	$40.80	$ 89.13	$(48.33)	(54)%

Average realized price (per Mcfe)	$ 3.79	$ 3.14	$3.28	$ 4.94	$(1.66)	(34)%

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Oil and Natural Gas Revenue

Natural gas, oil and condensate revenues on a pro forma basis decreased in 2016 compared to 2015 reflecting a decrease in our average realized sales prices for natural gas, oil and condensate and a reduction in natural gas, oil and condensate production. The decreases in natural gas, oil and condensate realized sales prices compared to 2015 contributed approximately $12.8 million to the decrease in natural gas, oil and condensate revenue, and the decrease in natural gas, oil and condensate production contributed approximately $38.7 million to the decrease in natural gas, oil and condensate revenue. The sale of our Eagle Ford Shale Trend properties in September 2015 contributed $22.9 million to the decrease in revenues attributed to decreased in volumes.

The difference on a pro forma basis between our average realized prices inclusive of net cash derivative settlements in the years ended December 31, 2016 and 2015 relates to our oil contracts. We had no natural gas derivative contract settlements during 2016 or 2015. We had no oil derivative settlements in 2016 while in 2015, we had oil derivative settlements on an average of 3,500 Bbls per day at an average fixed price of $96.11 per Bbl.

Operating Expenses

(in thousands)	October 13, to December 31, 2016	January 1, 2016 to October 12, 2016	Year Ended December 31,			
	Successor	Predecessor	Pro forma	Predecessor		
			2016	2015	Variance	
Lease operating expenses	$2,109	$ 6,504	$8,613	$ 15,522	$(6,909)	(45)%
Production and other taxes	619	1,946	2,565	4,639	(2,074)	(45)%
Transportation and processing	228	1,265	*	4,663	—	— %
Exploration	—	577	*	41,783	—	— %

Per Mcfe	October 13, to December 31, 2016	January 1, 2016 to October 12, 2016	Year Ended December 31,			
	Successor	Predecessor	Pro forma	Predecessor		
			2016	2015	Variance	
Lease operating expenses	$1.22	0.97	$1.02	$ 0.97	$0.05	5 %
Production and other taxes	$0.36	$ 0.29	$0.30	$ 0.29	$0.01	3 %
Transportation and processing	$0.13	$ 0.19	*	$ 0.29	—	— %
Exploration	—	$ 0.09	*	$ 2.61	—	— %

* Not comparable

Lease Operating Expense

Our lease operating expense (“LOE”) during 2016 on a pro forma basis decreased compared to 2015. The decrease was the result of a $4.8 million decrease from our Eagle Ford Shale Trend properties that were sold in September 2015 and lower operating costs for our TMS properties. Workover expense in 2016 for the Successor Company period was $0.4 million and for the Predecessor Company period was $0.8 million which added $0.23 and $0.12 per Mcfe respectively to unit expense compared to workover expense of $1.3 million in 2015 which added $0.08 per Mcfe to unit expense.

Production and Other Taxes

Production and other taxes for the year ended 2016 on a pro forma basis included production tax of $1.0 million and ad valorem tax of $1.6 million. Production and other taxes decreased in 2016 compared to 2015 mainly due to the sale of our Eagle Ford Shale Trend properties in September 2015. Lower production rates and lower commodity prices have been offset by a number of wells reaching their exemption maturity. The State of Mississippi has enacted an exemption from the existing 6.0% severance tax for horizontal wells drilled after July 1, 2013 with production commencing before July 1, 2018, which will be partially offset by a 1.3% local severance tax on such wells. The exemption is applicable until the earlier of (i) 30 months from the date of first sale of production or (ii) until payout of the well cost is achieved. The State of Louisiana has also enacted an exemption from the existing 12.5% severance tax for horizontal wells with production commencing after July 31, 1994. The exemption is applicable until the earlier of (i) 24 months from the date of first sale of production or (ii) until payout of the well cost is achieved. The net revenues from our wells drilled in our TMS acreage in Southwestern Mississippi and Southeast Louisiana have been favorably impacted by these exemptions.

Transportation and Processing

Transportation and processing expense for the 2016 Successor period reflects the restructuring of the marketing of our outside operated natural gas volumes in an effort to reduce transportation and processing cost.

Transportation and processing expense for the 2016 Predecessor period was generally lower due to lower produced natural gas volumes. Our natural gas production incurs substantially all of our transportation and processing cost.

Transportation and processing expense for the Predecessor in 2015 included $2.7 million in cost related to the Eagle Ford Shale properties sold in September 2015 which did not impact 2016 results.

Exploration

The Successor Company adopted the Full Cost Method of accounting as of October 12, 2016 resulting in Exploration Cost being capitalized to the full cost pool rather than expensed.

The Exploration expense in the Predecessor 2016 period was lower as result of the Leasehold impairments taken in in 2015.

The Exploration expense in the 2015 Predecessor period included leasehold impairments taken as result of our deemed financial inability to develop or extend the leases.

(in thousands)	October 13, to December 31, 2016	January 1, 2016 to October 12, 2016	For the Year Ended December 31, 2015
	Successor	Predecessor	Predecessor
Depreciation, depletion & amortization	$1,556	$ 8,276	$ 79,339
Impairment	2,486	1,583	452,037
General & administrative	2,200	14,474	27,702
Gain on sale of assets	(2)	(840)	(53,451)

Per Mcfe	October 13, to December 31, 2016	January 1, 2016 to October 12, 2016	For the Year Ended December 31, 2015
	Successor	Predecessor	Predecessor
Depreciation, depletion & amortization	$0.90	$ 1.24	$ 4.96
Impairment	$1.44	0.24	$ 28.25
General & administrative	1.28	2.16	$ 1.73
Gain on sale of assets	—	(0.13)	$ (3.34)

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

DD&A expense in the 2016 Successor period were calculated on the Full Cost Method of Accounting adopted upon our emergence from bankruptcy based upon asset values as of October 12, 2016 established by Fresh Start Accounting.

DD&A expense in the 2016 Predecessor Period reflects reduced rates due to the impairment taken in 2015, in addition to lower production.

DD&A expense in the 2015 Predecessor period reflects higher DD&A rates calculated before having taken $452 million impairment at the end of 2015 as discussed below. Additionally, the 2015 expense reflected the DD&A on the Eagle Ford Shale properties that were sold in September 2015.

Impairment

The Successor Company recorded a $2.5 million impairment on oil and gas properties as a result of the Full Cost Ceiling Test performed on December 31, 2016.

The Predecessor Company recorded a $1.6 million impairment on the value of materials inventory during the Predecessor 2016 Period.

We recorded a $452.0 million impairment in 2015, comprised of $135.6 million for our Haynesville Shale Trend properties, $310.2 million for our TMS properties and $7.0 million for other properties. The decline in oil and natural gas prices precipitated the loss of estimated proved reserves for our oil and natural gas producing properties. Additionally, the prospect of lower future prices had raised substantial doubt about our ability to continue as a going concern. Consequently all estimated proved undeveloped reserves had been excluded from our estimated total proved reserves as of December 31, 2015 and the carrying cost of the related undeveloped leasehold was impaired.

General and Administrative Expense (“G&A”)

The Successor Company recorded $2.2 million in G&A expense in 2016 which includes $0.2 million of share based compensation. As a result of adopting the Full Cost Method of Accounting, $0.5 million of G&A cost directly attributed to our capital development program was capitalized to the the full cost pool.

The Predecessor Company recorded $14.5 million in G&A expense in 2016 which includes $3.3 million in share based compensation. During the Predecessor 2016 period, we reduced our staff headcount by more than 30% from year-end 2015 levels. The higher rate per Mcfe for 2016 compared to 2015 reflects a 47% reduction in oil and natural gas production which increased per unit expenses.

The Predecessor Company recorded $27.7 million in G&A expenses which includes $6.7 million in share based compensation.

Gain on Sale of Assets

In 2015 the Predecessor recognized a $53.5 million gain on sale of assets. The 2015 gain is almost entirely associated with the sale of our proved reserves and a portion of the associated leasehold in the Eagle Ford Shale Trend located in La Salle and Frio counties in south Texas. In 2016, the Predecessor recognized $0.8 million gain on the settlement of the Eagle Ford Shale property escrow account.

No gain or loss was recognized for properties sold during the Successor period.

Other Income (Expense)

(In thousands)	October 13, to December 31, 2016 Successor	January 1, 2016 to October 12, 2016 Predecessor	Year Ended December 31, 2015 Predecessor
Other Income (Expense):			
Interest expense	$ (1,824)	$ (11,398)	$ (54,807)
Interest income and other	1	117	—
Gain (loss) on derivatives not designated as hedges	—	30	7,367
Gain on extinguishment of debt	—	—	62,555
Restructuring	—	(5,128)	—
Average funded borrowings adjusted for debt discount	26,399	*	579,393
Average funded borrowings	59,503	*	579,722

* - Not Meaningful

Interest Expense

Interest expense in the 2016 Predecessor period reflects interest only through April 15, 2016. which was our Bankruptcy Petition Date. We ceased accruing interest on the Second Lien Notes and unsecured senior notes on the Petition Date.

Interest expense in the Successor period reflects the interest incurred on the Exit Credit Facility and the Paid-in-Kind interest on the 13.50% Convertible Second Lien Notes due 2019.

Interest expense for the Predecessor year ended December 31, 2015 reflects interest on average outstanding borrowing of $579.7 million for the entire year.

Gain on Derivatives Not Designated as Hedges

The gain on derivatives was less than $0.03 million in 2016 Predecessor Period. We had no derivatives in the 2016 Successor period.
Gain on derivatives was $7.4 million for 2015. The gain includes net cash receipts of $54.3 million off set by the decrease in the fair value of $46.9 million. There were no natural gas derivative contract settlements during 2015. The decrease in the fair value consists of a $0.5 million gain on our natural gas derivatives and a $47.4 million loss on our oil derivatives. The decrease in fair value of our oil derivatives reflects settled contracts and the ultimate expiration of all of our oil derivative contracts in December 2015. The gain on our the natural gas derivative contracts is reflective of the portion of such contracts that expired during 2016 and the decline in natural gas futures prices in the latter half of 2015.

Restructuring

As a result of the efforts to restructure the Company outside of bankruptcy during the first quarter of 2016 and the subsequent preparation involved in filing the Chapter 11 Cases, we incurred significant professional fees and other costs. Restructuring costs during the first and second quarters of 2016 totaled $4.3 million and $0.8 million, respectively.

Reorganization items, net

The Predecessor Company realized a gain on reorganization in 2016 of $399.4 million as a result of implementing the Plan of Reorganization and adopting Fresh Start Accounting on October 12, 2016. The gain on the settlement of liabilities subject to compromise was $395.9 million and the gain on fresh start adjustments of $19.5 million was reduced by a net $16.0 million related to professional fees and adjustments to debt. Reorganization costs incurred for professional fees as of October 12, 2016 was $11.0 million. In addition to the costs of professional fees, reorganization cost was affected by various non-cash adjustments to the carrying amounts of our Second Lien Notes and senior notes, including a $5.5 million charge for the unwinding of an embedded derivative related to the Second Lien Notes. See Note 3- "Fresh Start Accounting" in the Notes to Consolidated Financial Statements in Item 8- "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Gain(loss) on Extinguishment of Debt

On October 1, 2015 the Predecessor exchanged $158.2 million of 2020 Notes for $75.0 million of new 8.875% Second Lien Notes. The transaction was accounted for as a troubled debt restructure and recognized a gain on extinguishment of debt of $62.6 million.

Income Tax Benefit

We recorded no income tax benefit for the years 2016 and 2015. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed and as a result, we continue to maintain a full valuation allowance for our net deferred asset as of December 31, 2016.

We elected to early adopt the provisions of ASU 2015-17, "Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes" in 2016 on a retrospective basis. The amendments in this update seek to simplify the presentation of deferred income taxes and require that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. The implementation did not have a material impact on the Company's consolidated statement of operations, balance sheet or statement of cash flows. As the noncurrent deferred tax amounts net to zero, they are no longer presented on the Consolidated Balance Sheets.

Adjusted EBITDA/EBITDAX

Adjusted EBITDA/EBITDAX is a supplemental non-US 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. EBITDA reflects the absence of exploration expense in the Full Cost Method of Accounting. We define Adjusted EBITDAX as earnings before interest expense, income tax, DD&A, exploration expense, share based compensation and impairment of oil and natural gas properties. In calculating Adjusted EBITDA/EBITDAX, gains/losses on derivatives, less net cash received or paid in settlement of commodity derivatives, gain on reorganization and gain on extinguishment of debt are excluded from Adjusted EBITDA/EBITDAX. Other excluded items include Interest income and other, Gain/loss on sale of assets, Gain/loss on early extinguishment of debt and Other expense. Adjusted EBITDA/EBITDAX is not a measure of net income (loss) as determined by US GAAP. Adjusted EBITDA/EBITDAX should not be considered an alternative to net income (loss), as defined by US GAAP. The following table presents a reconciliation of the non-US GAAP measure of Adjusted EBITDA/EBITDAX to the US GAAP measure of net income (loss), its most directly comparable measure presented in accordance with US GAAP.

	October 13, to December 31, 2016 Successor	January 1, 2016 to October 12, 2016 Predecessor	Year Ended December 31, 2015 Predecessor
(In thousands)			
Net gain (loss) (US GAAP)	$ (4,307)	$ 369,944	$ (479,424)
Depreciation, depletion and amortization	1,556	8,276	79,339
Exploration Expense	—	577	41,783
Impairment	2,486	1,583	452,037
(Gain) loss on extinguishment of debt	—	—	(62,555)
Stock based compensation	240	3,307	6,689
Interest expense	1,824	11,398	54,807
Gain on reorganization	(130)	(399,422)	—
(Gain) on derivatives not designated as hedges	—	(30)	(7,367)
Net cash received (paid) in settlement of derivative instruments	—	—	54,274
Other items (1)	(3)	(957)	(52,327)
Adjusted EBITDA/EBITDAX	$ 1,666	$ (5,324)	$ 87,256

(1) Other items include interest income and other, gain/loss on sale of assets, income taxes and other expense.

Management believes that this non-US GAAP financial measure provides useful information to investors because it is monitored and used by our management and widely used by professional research analysts in the valuation and investment recommendations of companies within the oil and natural gas exploration and production industry. Our computations of Adjusted EBITDA/EBITDAX may not be comparable to other similarly totaled measures of other companies.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Predecessor Company (January 1, 2016 to October 12, 2016)

Our primary sources of cash were cash on hand, cash from operating activities, cash proceeds from borrowings under our Senior Credit Facility and cash proceeds from the settlement of the escrow account associated with the our Eagle Ford Shale Trend producing properties sold in 2015. We used cash in 2016 to fund our capital spending, pay interest on amounts outstanding on the Senior Credit Facility and pay expenses associated with the bankruptcy.

On April 15, 2016 we filed a voluntary petition seeking relief under Chapter 11 of Title 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas, to pursue a Chapter 11 plan of reorganization. Our bankruptcy and subsequent emergence therefrom had a significant impact on our financial condition and operating results, including the extinguishment of approximately $426.2 in indebtedness related to the cancellation of our unsecured senior notes and other unsecured claims. We also incurred one-time costs that are associated with our reorganization, primarily professional fees, that affected our results of operations.

On August 4, 2016, the Bankruptcy Court approved a commitment letter (the “Commitment Letter”) between the Company and a group of investors for the issuance of 13.50% Convertible Senior Secured Second Lien Notes in the initial aggregate principal amount of $40.0 million (the “Convertible Second Lien Notes”).

On October 12, 2016, we entered into an Exit Credit Agreement by which various lenders agreed to provide us with a $20.0 million senior secured term loan credit facility, with an outstanding principal amount of $20.0 million. The Commitment Letter provided for the issuance of $40.0 million in Convertible Second Lien Notes that mature on the later of August 30, 2019 or six months after the maturity of the Exit Credit Agreement. A total of $20.0 million in proceeds from the issuance of the Convertible Second Lien Notes were used to repay amounts outstanding under the existing Second Amended and Restated Credit Agreement (including all amendments, the “Senior Credit Facility”) and $20.0 million in proceeds was and will be used to fund the Company’s Haynesville Shale Trend drilling program.

Successor Company (October 13, 2016 to December 31, 2016)

Our primary sources of cash on and after our emergence from bankruptcy on October 12, 2016 were cash on hand, cash flow from operating activities, proceeds from the sale of the Convertible Second Lien Notes, proceeds from the private placement of our common stock and proceeds from the sale of non-core oil and gas properties. We used cash to fund our capital expenditures, to pay interest on and pay down amounts outstanding on the Exit Credit Facility and to pay professional fees related to the reorganization.

Capital Resources

We have emerged from bankruptcy a much stronger company. We have $36.9 million cash on hand as of December 31, 2016. We believe that the cash on hand and the cash flows we are generating are sufficient to meet our investing, financing and working capital requirements in 2017. We believe the results of the capital investments we are making in 2017 will generate additional cash flows and additional value which will allow us to raise capital to continue our capital development into 2018 and beyond.

The table below summarizes our cash flows for the periods indicated (in thousands):

	October 13, to December 31, 2016	January 1, 2016 to October 12, 2016	For Year Ended December 31, 2015
Cash flow statement information:	Successor	Predecessor	Predecessor
Net Cash:			

Used in operating activities	$ (4,327)	$ (16,684)	$ (17,011)
Used in investing activities	(2,383)	(3,495)	(4,874)
Provided by financing activities	39,880	12,077	33,659
Increase (decrease) in cash and cash equivalents	$ 33,170	$ (8,102)	$ 11,774

At December 31, 2016, we had positive working capital of $28.6 million and $47.2 in long-term debt.

Cash Flows

For the Period October 13, 2016 to December 31, 2016

Operating activities: Production from our wells, the price of oil and natural gas and operating costs represent the main drivers of our cash flow from operations. Changes in working capital also impact cash flows. Net cash used in operating activities for the 2016 Successor period totaled $4.3 million impacted by the payment of $6.7 million of professional fees incurred and accrued in the prior period.

Investing activities: Net cash used in investing activities was $2.4 million for the 2016 Successor period. While we booked capital expenditures of approximately $4.3 million, we paid out cash amounts totaling $3.2 million in the period. The difference is attributed to utilizing $0.4 million of net cash calls and a net $0.5 million increased in the capital expenditure accrual. The Successor period also reflects the receipt of $0.8 million in proceeds from the December 2016 sale of the shallow rights in our Longwood properties located in Louisiana. We conducted drilling and completion operations on two gross wells in in the Successor period.

Financing activities: Net cash provided in financing activities for Successor period consisted of net proceeds from the issuance of 13.5% Second Lien Notes of $40.0 million and net proceeds from the sale of common stock of $23.6 million partially offset by net repayments of borrowings under the our Senior Credit and Exit Credit Facilities of $23.7 million.

Debt consisted of the following balances as of the dates indicated (in thousands):

	Successor December 31, 2016			Predecessor December 31, 2015		
	Principal	Carrying Amount	Fair Value	Principal	Carrying Amount (5)	Fair Value (1)
Exit Credit Facility (7)	$16,651	$16,651	16,651	$—	$—	$—
13.50% Convertible Second Lien Notes (8)	41,170	30,554	29,036	—	—	—
Senior Credit Facility	—	—	—	27,000	25,387	27,000
8.0% Second Lien Senior Secured Notes due 2018 (2) (6)	—	—	—	100,000	87,529	14,512
8.875% Second Lien Senior Secured Notes due 2018 (6)	—	—	—	75,000	91,364	7,586
8.875% Senior Notes due 2019 (6)	—	—	—	116,828	115,599	9,346
3.25% Convertible Senior Notes due 2026 (6)	—	—	—	429	429	64
5.0% Convertible Senior Notes due 2029 (3) (6)	—	—	—	6,692	6,692	67
5.0% Convertible Senior Notes due 2032 (4) (6)	—	—	—	98,664	95,882	6,923
5.0% Convertible Exchange Senior Notes due 2032 (6)	—	—	—	26,849	42,625	26,649
Total debt	$57,821	$47,205	$45,687	$451,462	$465,507	$92,147

(1) The carrying amount for the Senior Credit Facility represents fair value as it was fully secured. The fair values of the notes were obtained by direct market quotes within Level 1 of the fair value hierarchy. The fair value of our Second Lien Notes and 2032 Exchange Notes were obtained using a discounted cash flow model within Level 3 of the fair value hierarchy. Level 1 and Level 3 of the fair value hierarchy are defined in "Item 8 - Financial Statements and Supplementary Data."

(2) The debt discount was being amortized using the effective interest rate method based upon a two and a half year term through September 1, 2017, the first repurchase date applicable to the 8.0% Second Lien Notes. The $13.1 debt discount that existed when the Bankruptcy Petitions were filed on the Petition Date was written off to Reorganization items, net during the second quarter of 2016. The debt discount as of December 31, 2015 was $11.0

million.

(3) The debt discount was amortized using the effective interest rate method based upon an original five year term through October 1, 2014. The debt discount was fully amortized as of December 31, 2014.

(4) The debt discount was being amortized using the effective interest rate method based upon a four year term through October 1, 2017, the first repurchase date applicable to the 2032 Notes. The $1.7 million debt discount that existed when the Bankruptcy Petitions were filed on April 15, 2016 was written off to Reorganization items, net during the second quarter of 2016. The debt discount was $2.0 million as of December 31, 2015.

(5) The carrying amount of debt is net of deferred loan costs of $5.1 million as of December 31, 2015. Deferred financing costs were amortized using the straight-line method through the contractual maturity dates for the Senior Credit Facility and the 2019 Notes, through the first put date of September 1, 2017 for the 8.0% Second Lien Notes and through the first put date of October 1, 2017 for the 2032 Notes. The $3.0 million of deferred loan costs for the 2019 Notes, 8.0% Second Lien Notes and 2032 Notes that existed when the Bankruptcy Petitions were filed on the Petition date was written off to Reorganization items, net during the second quarter of 2016.

(6) Classified as Liability subject to compromise as of October 12, 2016.

(7) The carrying amount for the Exit Credit Facility represents fair value as it was fully secured.

(8) The debt discount is being amortized using the effective interest rate method based upon a maturity date of August 30, 2019. The principal includes $1.2 million of accrued Paid-In-Kind (PIK) interest. The carrying value includes $10.6 million of unamortized debt discount. The fair value of the notes was obtained by using a Binomial Lattice Model within Level 3 of the fair value hierarchy.

The following table summarizes the total interest expense (contractual interest expense, amortization of debt discount, accretion and financing costs) and the effective interest rate on the liability component of the debt (amounts in thousands, except effective interest rates) for the years ended:

	Period from October 13, 2016 through December 31, 2016			Period from January 1, 2016 through October 12, 2016		For the Year Ended December 31, 2015		
	Interest Expense	Effective Interest Rate		Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate	
Senior Credit Facility	$—	—		$3,342	—	$4,308	5.1	%
Exit Credit Facility	306	7.3	%	—	—	—	—	%
13.50% Convertible Second Lien Notes	1,518	24.7	%	—	—	—	—	%
8.0% Second Lien Senior Secured Notes due 2018	—	—		936	*	11,515	16.4	%
8.875% Second Lien Senior Secured Notes due 2018	—	—		—	—	2,333	*	
8.875% Senior Notes due 2019	—	—		3,107	*	21,668	9.2	%
3.25% Convertible Senior Notes due 2026	—	—		4	*	13	3.3	%
5.0% Convertible Senior Notes due 2029	—	—		97	*	335	5.0	%
5.0% Convertible Senior Notes due 2032	—	—		2,382	*	12,495	8.6	%
5.0% Convertible Exchange Senior Notes due 2032	—	—		1,484	*	2,088	*	
Other	—	—		46	*	52	*	
Total	$1,824			$11,398		$54,807		

* - Not meaningful

The Chapter 11 Cases constituted an event of default that accelerated the Company’s obligations under all of its outstanding debt instruments. The agreements governing the Company’s debt instruments provided that as a result of the Bankruptcy Petitions, the principal and interest due thereunder was immediately due and payable. However, any efforts to enforce such payment obligations under the Company’s debt instruments were automatically stayed as a result of the Chapter 11 Cases, and the creditors’ rights of enforcement in respect of the debt instruments were subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. On October 12, 2016, upon the Company's emergence from bankruptcy, the Second Lien Notes due 2018 were exchanged for 98% of the common stock of the reorganized Company and all the unsecured senior notes along with certain other unsecured claims were exchanged for 2% of the common stock of the reorganized company. The $40.4 million outstanding under the Senior Credit Facility was paid down $20.0 million with proceeds from the sale of the 13.5% Convertible Second Lien Notes due 2019 and cash on hand at closing.

Senior Credit Facility

On October 12, 2016, we had $40.4 million outstanding under the Senior Credit Facility inclusive of the accrued default penalty. Following the reduction of the borrowing base to $20.0 million after the April 1, 2016 borrowing base redetermination, the Company had a borrowing base deficiency of $20.2 million. Pursuant to the terms of a cash collateral order entered in the bankruptcy proceeding on the Petition Date, interest was accrued and paid monthly based on a 2.25% margin which calculated to 5.75% per annum. Additionally, a post-default rate of 2.00% was accreted on the outstanding balance. Substantially all of our assets were pledged as collateral to secure the Senior Credit Facility. The Senior Credit Facility had a maturity date of February 24, 2017.

The commencement of the Chapter 11 Cases on the Petition Date constituted an event of default that accelerated the Company's obligations under the Senior Credit Facility. Additionally, other events of default existed which included, but were not limited to, the presence of an explanatory paragraph regarding the substantial doubt about our ability to continue as a going concern in the report of our independent registered public accounting firm that accompanied our audited consolidated financial statements for the year ended December 31, 2015. We were also not in compliance with the certain financial covenants under the terms of the Senior Credit Facility as of September 30, 2016, June 30, 2016, March 31, 2016 and December 31, 2015. On October 12, 2016, in connection with the consummation of the Plan, the Senior Credit Facility was terminated.

Exit Credit Facility

On October 12, 2016, upon consummation of the Plan of Reorganization, the Company entered into an Exit Credit Agreement (the "Exit Credit Agreement") with the Subsidiary, as borrower (the "Borrower"), and Wells Fargo Bank, National Association, as administrative agent ("the Administrative Agent"), and certain other lenders party thereto. Pursuant to the Exit Credit Agreement, the lenders agreed to provide the Borrower with a $20.0 million senior secured term loan credit facility, with an outstanding principal amount of $20.0 million.

The maturity date of the Exit Credit Agreement is September 30, 2018, unless the Borrower notifies the Administrative Agent that it intends to extend the maturity date to September 30, 2019, subject to certain conditions and the payment of a fee.

Until such maturity date, the Loans (as defined in the Exit Credit Agreement) under the Exit Credit Agreement shall bear interest at a rate per annum equal to (i) the alternative base rate plus an applicable margin of 4.50% or (ii) adjusted LIBOR plus an applicable margin of 5.50%.

The Borrower may elect, at its option, to prepay any borrowing outstanding under the Exit Credit Agreement without premium or penalty (except with respect to any break funding payments which may be payable pursuant to the terms of the Exit Credit Agreement).

The Borrower may be required to make mandatory prepayments of the Loans under the Exit Credit Agreement if the total borrowings exceed the aggregate credit amounts, and if the Borrower is not in compliance with the Total Proved Asset Coverage Ratio (as defined in the Exit Credit Agreement) or the Secured Debt Asset Coverage Ratio (as defined in the Exit Credit Agreement).

Additionally, if the Borrower has outstanding borrowings and the Consolidated Cash Balance (as defined in the Exit Credit Agreement) and First Amendment and Consent to Exit Credit Agreement dated December 2016) exceeds (i) the sum of $27.5 million plus $21.3 million, which is calculated as the Equity Issuance Net Proceeds from the December 19, 2016 private placement of equity less $2.5 million as of the close of business on the most recently ended business day on or before March 31, 2018 or (ii) $7.5 million as of the close of business on the most recently ended business day on or after April 1, 2018, the Borrower may also be required to make mandatory prepayments in an aggregate principal amount equal to such excess.

Furthermore, the Borrower is required to make certain mandatory prepayments within one business day of (i) the issuance of any Equity Interests (as defined in the Exit Credit Agreement) of the Company, (ii) the consummation of any sale or other disposition of Property (as defined in the Exit Credit Agreement) and (iii) the assignment, termination or unwinding of any Swap Agreements (as defined in the Exit Credit Agreement).

Amounts outstanding under the Exit Credit Agreement are guaranteed by the Company and secured by a security interest in substantially all of the assets of the Company and the Borrower.

The Exit Credit Agreement contains certain customary representations and warranties, including organization; powers; authority; enforceability; approvals; no conflicts; financial condition; no material adverse change; litigation; environmental matters; compliance with laws and agreements; no defaults; Investment Company Act; taxes; ERISA; disclosure; no material misstatements; insurance; restrictions on liens; subsidiaries; location of business and offices; properties; titles, etc.; maintenance of properties; gas imbalances, prepayments; marketing of production; swap agreements; use of loans; solvency; sanctions laws and regulations; foreign corrupt practices; money laundering laws; and embargoed persons.

The Exit Credit Agreement also contains certain affirmative and negative covenants, including delivery of financial statements; conduct of business; reserve reports; title information; collateral and guarantee requirements; indebtedness; liens; dividends and distributions; investments; sale or discount of receivables; mergers; sale of properties; termination of swap agreements; transactions with affiliates; negative pledges; dividend restrictions; gas imbalances; take-or-pay or other prepayments; and swap agreements.

The Exit Credit Agreement also contains certain financial covenants, including the maintenance of (i) a Total Proved Asset Coverage Ratio (as defined in the Exit Credit Agreement) not to be less than 1.5 to 1.0 initially, and increasing to 2.0 to 1.0 or after December 31, 2018, (ii) Secured Debt Asset Coverage Ratio (as defined in the Exit Credit Agreement) not to be less than 1.10 to 1.00 initially, and increasing to 1.35 to 1.00 and 1.50 to 1.00 after March 31, 2017 and September 30, 2017, respectively, in the case of clauses (i) and (ii), to be determined as of January 1 and July 1 each year and as of the date of any Material Acquisition (as defined in the Exit Credit Agreement) or Material Disposition (as defined in the Exit Credit Agreement), (iii) commencing with the fiscal quarter ending March 31, 2018, a ratio of Debt (as defined in the Exit Credit Agreement) as of the end of each fiscal quarter to EBITDAX for the twelve months ending on the last day of such fiscal quarter, not to exceed 4.00 to 1.00, (iv) limitations on Consolidated Cash Balance, (v) limitations on general and administrative expenses and (vi) minimum liquidity requirements.

The Exit Credit Agreement also contains certain events of default, including non-payment; breaches of representations and warranties; non-compliance with covenants or other agreements; cross-default to material indebtedness; voluntary and involuntary bankruptcy; judgments; and change of control.

8.0% Second Lien Senior Secured Notes due 2018

On March 12, 2015, we sold 100,000 units (the "Units"), each consisting of a $1,000 aggregate principal amount at maturity of our 8.0% Second Lien Notes and one warrant to purchase 48.84 shares of our $0.20 par value common stock. The 8.0% Second Lien Notes were guaranteed by our subsidiary that also guaranteed our Senior Credit Facility. The 8.0% Second Lien Notes are secured on a senior second-priority basis by liens on certain assets of the Company and its subsidiary that secured our Senior Credit Facility, which liens were subject to an inter-creditor agreement in favor of the lenders under the Senior Credit Facility. The 8.0% Second Lien Notes were to mature on March 15, 2018 or on September 1, 2017, if certain conditions were not met. Interest on the 8.0% Second Lien Notes was payable semi-annually in arrears on March 15 and September 15 of each year, beginning on September 15, 2015.

The 8.0% Second Lien Notes and the warrants became separately transferable on June 4, 2015 when a registration statement related to the resale of the warrants was declared effective by the SEC. The warrants were exercisable upon payment of the exercise price of $4.664 or convertible on a cashless basis as set forth in the agreement governing the warrants.

We separately accounted for the liability and equity components of our 8.0% Second Lien Notes in a manner that reflected our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. We measured the debt component of the 8.0% Second Lien Notes using a discount rate of 32% on the date of issuance. We attributed $78.7 million of the 8.0% Second Lien Notes relative fair value to the debt component, which compared to the face value results in a debt discount of $21.3 million. Additionally, we recorded $15.8 million within additional paid-in capital representing the equity component of the 8.0% Second Lien Notes. The debt discount had been amortized using the effective interest rate method. The $13.1 million unamortized debt discount that remained when the

Bankruptcy Petitions were filed on the Petition Date was written off to Reorganization items, net during the second quarter of 2016. We also identified an embedded derivative associated with the 8.0% Second Lien Notes stemming from the length of time between the maturity date of March 15, 2018 and the put date of September 1, 2017. We valued the embedded derivative at $5.9 million using the discounted cash flow method on the date of issuance. The embedded derivative feature was recorded at fair value each reporting period with changes in fair value being reported as interest expense in the consolidated statements of operations. The $0.9 million fair value of the embedded derivative that existed when the Bankruptcy Petitions were filed on April 15, 2016 was reduced to zero during the second quarter of 2016. On October 12, 2016, the obligations of the Company with respect to the 8.0% Second Lien Notes were canceled.

8.875% Second Lien Senior Secured Notes due 2018

On October 1, 2015, we closed on a privately-negotiated exchange agreement under which we retired, in two tranches, \$158.2 million in principal of our 2019 Notes for \$75.0 million in principal of 8.875% Second Lien Notes. The first tranche exchanged \$81.7 million of 2019 Notes for \$36.8 million of 8.875% Second Lien Notes. The second tranche exchanged \$76.5 million of 2019 Notes for \$38.2 million of 8.875% Second Lien Notes which also included the issuance of 38,250 warrants. Each warrant was entitled to purchase approximately 156.9 shares of our \$0.20 par value common stock for \$1.00 per share. The 8.875% Second Lien Notes are secured on a senior second-priority basis by liens on certain assets of the Company and its subsidiary that secures our Senior Credit Facility, which liens are subject to an inter-creditor agreement in favor of the lenders under the Senior Credit Facility. The new 8.875% Second Lien Notes had a maturity date of March 15, 2018 or earlier on August 1, 2017 if certain conditions were not met. Interest on the 8.875% Second Lien Notes was payable semi-annually in arrears on March 15 and September 15 of each year, beginning on March 15, 2016.

We accounted for this transaction as a troubled debt transaction pursuant to guidance provided by FASB ASC section 470-60 “Troubled Debt Restructurings by Debtors”. We have determined that the prospective undiscounted cash flows from the 8.875% Second Lien Notes through their maturity did not exceed the adjusted carrying amount of the retired 2019 Notes, consequently a gain of \$62.6 million was recognized for this exchange in 2015. Accordingly, on the date of the exchange, a carrying amount of \$91.4 million was recorded as a liability and we recorded \$2.5 million in additional paid in capital representing the fair value of the warrants issued. On a basic and diluted loss per share basis the \$62.6 million gain was \$1.11 per share for the year ended December 31, 2015. The carrying amount of the 8.875% Second Lien Notes was adjusted downward from \$91.4 million to the \$75.0 million principal amount when the Bankruptcy Petitions were filed on the Petition Date, with the \$16.4 million gain recognized in Reorganization items, net on the Consolidated Statements of Operations for the three and nine months ended September 30, 2016. On October 12, 2016, the obligations of the Company with respect to the 8.875% Second Lien Notes were canceled.

8.875% Senior Notes due 2019

On March 2, 2011, we sold \$275 million of our 2019 Notes. The 2019 Notes were to mature on March 15, 2019, unless earlier redeemed or repurchased. The 2019 Notes were our senior unsecured obligations and ranked equally in right of payment to all of our other existing and future unsecured indebtedness. The 2019 Notes accrued interest at a rate of 8.875% annually, and interest was paid semi-annually in arrears on March 15 and September 15. The 2019 Notes were guaranteed by our subsidiary that also guarantees our Senior Credit Facility.

As described above, on October 1, 2015, we closed a privately-negotiated exchange under which we retired, in two tranches, \$158.2 million in aggregate original principal amount of our outstanding 2019 Notes in exchange for the issuance of \$75.0 million in aggregate original principal amount of our 8.875% Second Lien Notes and 38,250 warrants. Each warrant is entitled to purchase approximately 156.9 shares of our \$0.20 par value common stock for \$1.00 per share. On October 12, 2016, the obligations of the Company with respect to the 2019 Notes were canceled.

5.0% Convertible Senior Notes due 2029

In September 2009, we sold \$218.5 million of our 2029 Notes. The 2029 Notes were to mature on October 1, 2029, unless earlier converted, redeemed or repurchased. We exchanged \$166.7 million of the 2029 Notes for the 2032 Notes in 2013. On October 1, 2014, we repurchased \$45.1 million of the 2029 Notes using restricted cash held in escrow for that purpose.

The 2029 Notes were our senior unsecured obligations and rank equally in right of payment to all of our other existing and future unsecured indebtedness. The 2029 Notes accrued interest at a rate of 5.0% annually, and interest was paid semi-annually in arrears on April 1 and October 1 of each year. On October 12, 2016, the obligations of the Company with respect to the 2029 Notes were canceled.

5.0% Convertible Senior Notes due 2032

As described above, we entered into separate, privately negotiated exchange agreements in which we retired \$166.7 million in aggregate principal amount of our outstanding 2029 Notes in exchange for the issuance of the 2032 Notes in an aggregate principal amount of \$166.3 million. The 2032 Notes had a maturity date of October 1, 2032.

On September 8, 2015, we closed a privately-negotiated exchange under which we retired $55.0 million in aggregate original principal amount of our outstanding 2032 Notes in exchange for our issuance of a new series of 2032 Exchange Notes in an aggregate original principal amount of approximately $27.5 million. On October 14, 2015, we closed an additional privately-negotiated exchange under which we retired approximately $17.1 million in aggregate original principal amount of our outstanding 2032 Notes in exchange for our issuance of additional 2032 Exchange Notes in an aggregate original principal amount of approximately $8.5 million. As of September 30, 2016, $94.2 million in aggregate principal amount of the 2032 Notes remained outstanding.

Unlike the 2029 Notes, the principal amount of the 2032 Notes accreted at a rate of 2% per year compounded semi-annually which commenced on August 26, 2013. The accreted portion of the principal was payable in cash upon maturity but did not bear cash interest and was not convertible into our common stock. Holders had the option to require us to purchase any outstanding 2032 Notes on each of October 1, 2017, 2022 and 2027, at a price equal to 100% of the principal amount plus the accretion thereon. No accretion expense has been recognized on the 2032 Notes subsequent to the Bankruptcy Petitions being filed on the Petition Date. We recorded $0.1 million and $0.7 million of accretion in the three and nine months ended September 30, 2016, respectively, while we recorded $0.8 million and $2.5 million of accretion in the three and nine months ended September 30, 2015, respectively.

We separately accounted for the liability and equity components of our 2032 Notes in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. We measured the debt component of the 2032 Notes using an effective interest rate of 8%. We attributed $158.8 million of the fair value to the 2032 Note debt component which compared to the face results in a debt discount of $7.5 million which was being amortized through the first put date of October 1, 2017. Additionally, we recorded $24.4 million within additional paid-in capital representing the equity component of the 2032 Notes. The $1.7 million debt discount that existed when the Bankruptcy Petitions were filed on the Petition Date was written off to Reorganization items, net during the second quarter of 2016. On October 12, 2016, the obligations of the Company with respect to the 2032 Notes were canceled.

5.0% Convertible Senior Exchange Notes due 2032

On September 8, 2015, we closed a privately-negotiated exchange under which we retired $55.0 million in principal amount of outstanding 2032 Notes in exchange for our issuance of approximately $27.5 million in aggregate original principal amount of 2032 Exchange Notes. On October 14, 2015, we closed an additional privately-negotiated exchange under which we retired approximately $17.1 million in aggregate original principal amount of our outstanding 2032 Notes in exchange for our issuance of additional 2032 Exchange Notes in an aggregate original principal amount of approximately $8.5 million. Many terms of the 2032 Exchange Notes remain the same as the 2032 Notes they replaced, including the 5.0% annual cash interest rate and the final maturity date of October 1, 2032.

Like the 2032 Notes, the principal amount of the 2032 Exchange Notes accreted at a rate of 2% per year from August 26, 2013, compounding on a semi-annual basis. The accreted portion of the principal was payable in cash upon maturity but did not bear cash interest and was not convertible into our common stock.

We accounted for these exchange transactions as troubled debt restructuring transactions pursuant to guidance provided by FASB ASC section 470-60 “Troubled Debt Restructurings by Debtors”. We have determined that the prospective undiscounted cash flows from the 2032 Exchange Notes through their maturity exceed the adjusted carrying amount of the retired 2032 Notes, consequently a gain on extinguishment of debt was not recognized for these exchanges. Accordingly, on the date of the September 8, 2015 exchange, a carrying amount of $45.2 million remained as a liability and we recorded $10.1 million to additional paid in capital representing the net fair value of the convert feature. On the date of the October 14, 2015 exchange, a carrying amount of $14.8 million remained as a liability and we recorded $2.5 million to additional paid in capital representing the net fair value of the convert feature. An annual discount rate of 1.3% and 1.4%, respectively, was being used to amortize the liability until maturity on October 1, 2032. During 2016, holders converted an aggregate amount of $32.4 million of 2032 Exchange Notes into our common stock. The carrying amount of the 2032 Exchange Notes was adjusted downward from $10.2 million to the $6.3 million principal amount when the Bankruptcy Petitions were filed on April 15, 2016, with the $3.9 million gain recognized in Reorganization items, net on the Consolidated Statements of Operations for the three and nine months ended September 30, 2016. On October 12, 2016, the obligations of the Company with respect to the 2032 Exchange Notes were canceled.

3.25% Convertible Senior Notes Due 2026

On October 12, 2016, the obligations of the Company with respect to the 2026 Notes were canceled.

Interest Expense on Notes

There was no interest expense recognized on the Second Lien Notes or unsecured senior notes after the Bankruptcy Petitions were filed. The unrecorded interest expense on the Second Lien Notes and unsecured senior notes totaled $5.9 million and $13.5 million. On October 12, 2016, the obligations of the Company with respect to interest expense were canceled.

13.50% Convertible Second Lien Senior Secured Notes Due 2019

On October 12, 2016, the Company and the Subsidiary, entered into a purchase agreement (the “Purchase Agreement”) with each entity identified as a Shenkman Purchaser on Appendix A to the Purchase Agreement (collectively, the “Shenkman Purchasers”), CVC Capital Partners (acting through such of its affiliates to managed funds as it deems appropriate), J.P. Morgan Securities LLC (acting through such of its affiliates or managed funds as it deems appropriate), Franklin Advisers, Inc. (as investment manager on behalf of certain funds and accounts), O’Connor Global Multi-Strategy Alpha Master Limited and Nineteen 77 Global Multi-Strategy Alpha (Levered) Master Limited (collectively, and together with each of their successors and assigns, the “Purchasers”), in connection with the issuance of $40.0 million aggregate principal amount of the Company’s Convertible Second Lien Notes.

The aggregate principal amount of the Convertible Second Lien Notes will be convertible at the option of the Purchasers at any time prior to the scheduled maturity date into an amount of the Company’s common stock, par value $0.01 per share (the “New Common Stock”) equal to 15% of the New Common Stock of the reorganized Company on a fully diluted basis. Upon closing, the Purchasers will be issued 10-year costless warrants for common stock equal to 20% of the New Common Stock of the reorganized Company on a fully diluted basis, will take a second priority lien on all assets of the Debtors, and will have the right to appoint two members to the Board.

The Convertible Second Lien Notes will mature on August 30, 2019, or such later date as set forth in the Convertible Second Lien Notes, but in no event later than March 30, 2020. The Convertible Second Lien Notes bear interest at the rate of 13.50% per annum, payable quarterly in arrears on January 15, April 15, July 15 and October 15 of each year. The Company may elect to pay all or any portion of interest in kind on the then outstanding principal amount of the Convertible Second Lien Notes by increasing the principal amount of the outstanding Convertible Second Lien Notes or by issuing additional Second Lien Notes (“PIK Interest Notes”). The PIK Interest Notes will not be convertible. During such time as the Exit Credit Agreement (but not any refinancing or replacement thereof) is in effect, interest on the Convertible Second Lien Notes must be paid in-kind.

Cancellation of Preferred Stock

Beginning in the third quarter of 2015 all preferred stock dividend declarations and payments were suspended. If we failed to pay dividends on our Series B Preferred Stock on any six dividend payment dates, whether or not consecutive, the dividend rate per annum would have been increased by 1.0% until we had paid all dividends on our Series B Preferred Stock for all dividend periods up to and including the dividend payment date on which the accumulated and unpaid dividends are paid in full. If we failed to pay dividends for six or more quarterly periods, whether or not consecutive, on our Series C Preferred Stock or Series D Preferred Stock the holders would have received limited voting rights. In aggregate there were $25.8 million and $10.5 million of dividends in arrears as of September 30, 2016 and December 31, 2015, respectively, for the outstanding shares of our Series B, C and D Preferred Stock. On October 12, 2016, the obligations of the Company with respect to the Series B, C and D Preferred Stock were canceled.

Conversions to Common Stock

In 2016, we issued 9.8 million shares of our common stock to holders that exercised their conversion rights on $19.6 million face amount of the 2032 Exchange Notes. We recorded the $32.4 million carrying amount of the converted 2032 Exchange Notes to stockholders’ equity. See Note 3.

Additionally, in 2016, we issued 2.5 million shares of our common stock to Series E Preferred Stock holders that exercised their conversion rights on approximately 1,032,610 depositary shares of Series E Preferred Stock. On

October 12, 2016, the obligations of the Company with respect to the Series E Preferred Stock were canceled.
$25 Million Common Stock Private Placement
On December 19, 2016, we entered into an agreement to sell 2,272,727 shares of our common stock at $11.00 per share in a private placement realizing gross proceeds of $25 million. The shares were sold to selected institutional and accredited investors. We plan to use the net proceeds from the offering to fund our 2017 Haynesville Shale Trend development drilling program and for general corporate purposes, including working capital.

For additional information on our debt and equity instruments, see Note 6—Debt and Note 9—Stockholders' Equity in the Notes to Consolidated Financial Statements in "Item 8—Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Future Commitments

The table below (in thousands) provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2016. In addition to the contractual obligations presented in the table below, our Consolidated Balance Sheet at December 31, 2016 reflects accrued interest on our bank debt of $0.3 million payable in the first half of 2017. For additional information see Note 6—Debt and Note 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements in "Item 8—Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

	Payment due by Period						
	Note	Total	2017	2018	2019	2020	2020 and After
Debt	6	$75,315	$—	$16,651	$58,664	$—	$—
Office space leases		5,919	816	1,510	1,540	1,540	513
Office equipment leases		77	77	—	—	—	—
Operations contracts		855	799	20	20	16	—
Total contractual obligations (1)		$82,166	$1,692	$18,181	$60,224	$1,556	$513

(1) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $2.9 million as of December 31, 2016. We record a separate liability for the asset retirement obligations. See Note 5—Asset Retirement Obligation in the Notes to Consolidated Financial Statements in "Item 8—Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

2017 Outlook

On February 22, 2017, a 2017 capital expenditure budget of $40.0 million to $50.0 million, subject to market conditions, was approved by the Board of Directors. The budget's planned focus is on the Haynesville Shale play in North Louisiana, and contemplates 12 - 16 gross (3 - 4 net) wells utilizing new completion techniques.

Summary of Critical Accounting Policies and Estimates

The following summarizes several of our critical accounting policies. See a complete list in Note 1—Description of Business and Accounting Policies in the Notes to Consolidated Financial Statements in "Item 8—Financial Statements and Supplementary Data" of this Annual Report on Form 10-K.

Proved Oil and Natural Gas Reserves

Proved reserves are defined by the SEC as 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 regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserves estimates if the extraction is by means not involving a well. Although our external engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates used by us. We cannot predict the types of reserve revisions that will be required in future periods.

While the estimates of our proved reserves at December 31, 2016 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the SEC rules, those estimates could differ materially from our actual results.

Fresh Start Accounting

In connection with the Company’s emergence from bankruptcy, the Company is required to apply fresh start accounting to its financial statements because (i) the holders of existing voting shares of the Company prior to its emergence received less than 50% of the voting shares of the Company outstanding following its emergence from bankruptcy and (ii) the reorganization value of the Company’s assets immediately prior to confirmation of the Plan of Organization was less than the post-petition liabilities and allowed claims. Fresh start accounting will be applied to the Company’s consolidated financial statements as of October 12, 2016, the date on which the Company emerged from bankruptcy. Under the principles of fresh start accounting, a new reporting entity was considered to be created, and, as a result, the Company will allocate the reorganization value of the Company to its individual assets based on their estimated fair values. As a result of the application of fresh start accounting and the effects of the implementation of the Plan of Reorganization, the financial statements on or after October 12, 2016 will not be comparable with the financial statements prior to that date. For additional information on fresh start accounting and its effects on our financial statements, see Note 3 "Fresh Start Accounting" to our consolidated financial statements.

Transition from Successful Efforts Method to Full Cost Accounting Method

Under U.S. Generally Accepted Accounting Principles ("GAAP"), two acceptable methods of accounting for oil and gas properties are allowed. These are the Successful Efforts Method and the Full Cost Method. Entities engaged in the production of oil and gas have the option of selecting either method for application in the accounting for their properties. The principal differences between the two methods are in the treatment of exploration costs, the computation of DD&A expense and the assessment of impairment of oil and gas properties.

Prior to October 12, 2016, we followed the Successful Efforts Method of Accounting for exploration and development expenditures. Under this method, costs of acquiring unproved and proved oil and natural gas leasehold acreage are capitalized. When proved reserves are found on an unproved property, the associated leasehold cost is transferred to proved properties. Significant unproved leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Costs of all other unproved leases are amortized over the estimated average holding period of the leases. Development costs are capitalized, including the costs of unsuccessful development wells. Additionally, oil and gas properties are assessed for impairment in accordance with Accounting Standards Codification 360.

Because a new entity has been created at the Effective Date, and there is no comparability to the predecessor company financial statements, upon emergence from bankruptcy we elected to adopt the Full Cost Method of Accounting. We believe that the true cost of developing a “portfolio” of reserves should reflect both successful and unsuccessful attempts at exploration and production. Application of the Full Cost method of accounting will better reflect the true economics of exploring for and developing our oil and gas reserves. Therefore, as of October 12, 2016, we have used the Full Cost method to account for our investment in oil and gas properties in the reorganized company.

Under the Full Cost Method, we will capitalize all costs associated with acquisitions, exploration, development and estimated abandonment costs. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, but do not include any costs related to production, general corporate overhead or similar activities. Unevaluated property costs are excluded from the amortization base until we make a determination as to the existence of proved reserves on the respective property. We now review our unevaluated properties at the end of each quarter to determine whether the costs should be reclassified to proved oil and gas properties and thereby subject to DD&A. Our sales of oil and gas properties are now accounted for as adjustments to net proved oil and gas properties with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves. Additionally, we capitalize a portion of the costs of interest incurred on our debt based upon the balance of our unevaluated property costs and our weighted-average borrowing rate.

All exploratory costs are now capitalized, and DD&A expense is now computed on cost centers represented by entire countries. Our oil and gas properties are subject to a "ceiling test" to assess for impairment, as discussed below, under the Full Cost Method.

We amortize our investment in oil and gas properties through DD&A expense using the units of production (the “UOP”) method. This entails the provision for DD&A expense being computed by dividing production volumes for the period by the total proved reserves as of the beginning of the period (beginning of period reserves being determined by adding production to the end of period reserves), and applying the respective rate to the net cost of proved oil and gas properties and future development costs.

Full Cost Ceiling Test

The Full Cost Method requires that at the conclusion of each financial reporting period, the present value of estimated future net cash flows from proved reserves (adjusted for hedges and excluding cash flows related to estimated abandonment costs), be compared to the net capitalized costs of proved oil and gas properties, net of related deferred taxes. This comparison is referred to as a "ceiling test". If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows. Estimated future net cash flows from proved reserves are calculated based on a 12-month average pricing assumption.

Fair Value Measurement

Fair value is defined by Accounting Standards Codification (“ASC”) 820 as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. We carry our derivative instruments at fair value and measure their fair value by applying the income approach provided for ASC 820, using Level 2 inputs based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our credit worthiness or that of our counterparties. We carry our oil and natural gas properties held for use at historical cost or their estimated fair value if an impairment has been identified. We use Level 3 inputs, which are unobservable data such as discounted cash flow models or valuations, based on our various assumptions and future commodity prices to determine the fair value of our oil and natural gas properties in determining impairment. We carry cash and cash equivalents, account receivables and payables at carrying value which represent fair value because of the short-term nature of these instruments. For definitions for Level 1, Level 2 and Level 3 inputs see Note 2—summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements in “Item 8—Financial Statements and Supplementary Data” of this Annual Report on Form 10-K.

Impairment of Properties (Under Successful Efforts)

We monitor our long-lived assets recorded in oil and natural gas properties in the Consolidated Balance Sheets to ensure that they are not overstated. We must evaluate our properties for potential impairment when certain indicators or circumstances indicate that the carrying value of an asset may not be recoverable from future cash flows. Performing these evaluations requires a significant amount of judgment since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable proved and probable oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, the availability of capital to develop proved undeveloped reserves and future inflation levels. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserves or other changes to contracts, environmental regulations or tax laws. We cannot predict the amount of impairment charges that may be recorded in the future.

Asset Retirement Obligations

We make estimates of the future costs of the retirement obligations of our producing oil and natural gas properties in order to record the liability as required by the applicable accounting standard. This requirement necessitates us to make estimates of our property abandonment costs that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to significant revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.

Income Taxes

We are subject to income and other related taxes in areas in which we operate. When recording income tax expense, certain estimates are required by management due to timing and the impact of future events on when income tax expenses and benefits are recognized by us. We periodically evaluate our tax operating loss and other carry-forwards to determine whether a gross deferred tax asset, as well as a related valuation allowance, should be recognized in our financial statements.
Accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. See Note 1—Description of Business and Accounting Policies—Income Taxes and Note 8—Income Taxes in the Notes to Consolidated Financial Statements in “Item 8— Financial Statements and Supplementary Data” of this Annual Report on Form 10-K.

Share-Based Compensation Plans

For all new, modified and unvested share-based payment transactions with employees, we measure the fair value on the grant date and recognize it as compensation expense over the requisite period. Our common stock does not pay dividends therefore, the dividend yield is zero. The fair value of restricted stock is measured using the closing stock price on the day of the award.

New Accounting Pronouncements

See Note 2—Summary of Significant Accounting Policies—New Accounting Pronouncements in the Notes to Consolidated Financial Statements in “Item 8—Financial Statements and Supplementary Data” of this Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

We do not currently have any off-balance sheet arrangements for any purpose.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our primary market risks are attributable to fluctuations in commodity prices and interest rates. These fluctuations can affect revenues and cash flow from operating, investing and financing activities. Our risk-management policies provide for the use of derivative instruments to manage these risks. The types of derivative instruments utilized by us include futures, swaps, options and fixed-price physical-delivery contracts. The volume of commodity derivative instruments utilized by us may vary from year to year and is governed by risk-management policies with levels of authority delegated by the Board of Directors. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin deposit requirements, and we may be required from time to time to deposit cash or provide letters of credit with exchange brokers or its counterparties in order to satisfy these margin requirements.

For information regarding our accounting policies and additional information related to our derivative and financial instruments, see Note 1—Description of Business and Management Plan, Note 10—Derivative Activities and Note 6—Debt in the Notes to Consolidated Financial Statements in “Item 8— Financial Statements and Supplementary Data” of this Annual Report on Form 10-K.

Commodity Price Risk

Our most significant market risk relates to fluctuations in natural gas and crude oil prices. Management expects the prices of these commodities to remain volatile and unpredictable. As these prices decline or rise significantly, revenues and cash flow will also decline or rise significantly. Furthermore, additional non-cash write-downs of our oil and natural gas properties may be required if future commodity prices experience further sustained and significant declines. During 2015, we utilized derivatives to manage commodity price risk for a portion of our production. As of December 31, 2016, we did not have any outstanding derivative contracts. Below is a sensitivity analysis of our commodity-price-related derivative instruments at December 31, 2015.

We had derivative instruments in place to reduce the price risk associated with production in 2015 of approximately 3,500 Bbls per day of crude oil which expired on December 31, 2015. At December 31, 2015, we had a de minimis liability derivative position related to natural gas derivative instruments. We did not enter into derivatives instruments for trading purposes. Utilizing actual derivative contractual volumes, a hypothetical 10% increase in underlying commodity prices would have increased the derivative liability position, while a hypothetical 10% decrease in underlying commodity prices would have decreased the derivative liability. The aforementioned decrease and increase in the derivative liability position would have been de minimis to our consolidated financial statements as of December 31, 2015. Furthermore, a gain or loss would have been substantially offset by an increase or decrease, respectively, in the actual sales value of production covered by the derivative instruments.

Interest Rate Risk

As of December 31, 2016, we had $16.7 million outstanding variable-rate debt and $41.2 million of principal fixed-rate debt. In the past, we have entered into interest rate swaps to help reduce our exposure to interest rate risk, and we may seek to do so in the future if we deem appropriate. As of December 31, 2016 and 2015, we had no interest rate swaps.

Credit Risks

Our exposure to non-payment or non-performance by our customers and counterparties presents a credit risk. Generally, non-payment or non-performance results from a customer’s or counterparty’s inability to satisfy obligations. We monitor the creditworthiness of our customers and counterparties and established credit limits according to our credit policies and guidelines. We have the ability to require cash collateral as well as letters of credit from our financial counterparties to mitigate our exposure above assigned credit thresholds. We routinely exercise our contractual right to net realized gains against realized losses when settling with our financial counterparties. We may also be exposed to credit risk due to the concentration of our customers in the energy industry, as our customers may be similarly affected by prolonged changes in economic and industry conditions, or by the sale our oil and natural gas production to a limited number of purchasers.

Item 8. Financial Statements and Supplementary Data

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT’S ANNUAL REPORT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States. Our internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles in the United States, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and board of directors of the Company and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

We assessed the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (COSO). Based on our evaluation under the framework in Internal Control—Integrated Framework, we have concluded that our internal control over financial reporting was effective as of December 31, 2016.

Management of Goodrich Petroleum Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Goodrich Petroleum Corporation

We have audited the accompanying consolidated balance sheet of Goodrich Petroleum Corporation and subsidiary (the “Company”) as of December 31, 2016 (Successor) and the related consolidated statements of operations, stockholders’ equity and cash flows for the periods from October 13, 2016 through December 31, 2016 (Successor), and January 1, 2016 through October 12, 2016 (Predecessor). These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Goodrich Petroleum Corporation and subsidiary as of December 31, 2016 (Successor) and the results of their operations and their cash flows for the periods from October 13, 2016 through December 31, 2016 (Successor) and January 1, 2016 through October 12, 2016 (Predecessor), in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, the Company emerged from bankruptcy on October 12, 2016. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification 852-10, Reorganizations, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods as described in Note 2.

/s/ Hein & Associates LLP

Houston, Texas
March 3, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Goodrich Petroleum Corporation

We have audited the accompanying consolidated balance sheet of Goodrich Petroleum Corporation and subsidiary as of December 31, 2015 and the related consolidated statements of operations, cash flows, and stockholders' equity/(deficit) for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Goodrich Petroleum Corporation and subsidiary at December 31, 2015, and the consolidated results of their operations and their cash flows for the year ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas
March 30, 2016

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
(In Thousands)

	Successor December 31, 2016	Predecessor December 31, 2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$36,850	$ 11,782
Accounts receivable, trade and other, net of allowance	1,998	1,255
Accrued oil and natural gas revenue	3,142	3,421
Inventory	4,125	5,652
Prepaid expenses and other	755	1,119
Total current assets	46,870	23,229
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties (successful efforts method)	—	974,012
Unevaluated properties	24,206	—
Oil and gas properties (full cost method)	60,936	—
Furniture, fixtures and equipment	984	7,592
	86,126	981,604
Less: Accumulated depletion, depreciation and amortization	(4,006)	(911,072)
Net property and equipment	82,120	70,532
Other	$322	90
TOTAL ASSETS	$129,312	$ 93,851
LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable	$14,392	$ 19,673
Accrued liabilities	3,882	12,508
Accrued abandonment costs	—	83
Fair value of oil and natural gas derivatives	—	30
Current portion of debt	—	465,507
Total current liabilities	18,274	497,801
Long term debt, net	47,205	—
Accrued abandonment cost	2,933	3,645
Other non-current liability	—	490
Total liabilities	68,412	501,936
Commitments and contingencies (See Note 11)		
STOCKHOLDERS' EQUITY/(DEFICIT):		
Predecessor Preferred stock: 10,000,000 shares $1.00 par value authorized:		
Predecessor Series B cumulative convertible preferred stock, issued and outstanding zero and 1,491,459 shares, respectively	—	1,491
Predecessor Series C cumulative preferred stock, issued and outstanding zero and 3,125 shares, respectively	—	3
Predecessor Series D cumulative preferred stock, issued and outstanding zero and 3,736 shares, respectively	—	4
Predecessor Series E cumulative preferred stock, issued and outstanding zero and 3,553 shares, respectively	—	4

Predecessor Common stock: $0.20 par value, 150,000,000 shares authorized, issued and outstanding zero and 63,910,300 shares, respectively	—	12,782
Predecessor Treasury stock (zero and 173,641 shares, respectively)	—	(41)
Successor Preferred stock: 10,000,000 shares $1.00 par value authorized, and none issued and outstanding	—	—
Successor Common stock: $0.01 par value, 75,000,000 shares authorized, and 9,108,826 shares issued and outstanding	91	—
Additional paid in capital	65,116	1,069,673
Retained earnings (accumulated deficit)	(4,307)	(1,492,001)
Total stockholders' equity/(deficit)	60,900	(408,085)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)	$ 129,312	$ 93,851

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, Except Per Share Amounts)

	Successor Period from October 13, 2016 to December 31, 2016	Predecessor Period from January 1, 2016 to October 12, 2016	Predecessor Year ended December 31, 2015
REVENUES:			
Oil and natural gas revenues	$ 6,537	$ 21,027	$ 79,077
Other	45	(341)	(1,427)
	6,582	20,686	77,650
OPERATING EXPENSES:			
Lease operating expense	2,109	6,504	15,522
Production and other taxes	619	1,946	4,639
Transportation and processing	228	1,265	4,663
Depreciation, depletion and amortization	1,556	8,276	79,339
Exploration	—	577	41,783
Impairment	2,486	1,583	452,037
General and administrative	2,200	14,474	27,702
(Gain) loss on sale of assets	(2)	(840)	(53,451)
Other	—	—	(45)
	9,196	33,785	572,189
Operating loss	(2,614)	(13,099)	(494,539)
OTHER INCOME (EXPENSE):			
Interest expense	(1,824)	(11,398)	(54,807)
Interest income and other	1	117	—
Gain on derivatives not designated as hedges	—	30	7,367
Gain on extinguishment of debt	—	—	62,555
Restructuring	—	(5,128)	—
	(1,823)	(16,379)	15,115
Reorganization items, net	130	399,422	—
Income (loss) before income taxes	(4,307)	369,944	(479,424)
Income tax provision	—	—	—
Net income (loss)	(4,307)	369,944	(479,424)
Preferred stock, net	—	11,237	(69,544)
Net income (loss) applicable to common stock	$ (4,307)	$ 358,707	$ (409,880)
PER COMMON SHARE			
Net income (loss) applicable to common stock—basic	$ (0.60)	$ 4.64	$ (7.28)
Net income (loss) applicable to common stock—diluted	$ (0.60)	$ 3.69	$ (7.28)
Weighted average common shares outstanding—basic	7,184	77,236	56,315
Weighted average common shares outstanding—diluted	7,184	98,369	56,315

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

	Successor	Predecessor	
	October 13, to December 31, 2016	January 1, 2016 to October 12, 2016	Year Ended December 31, 2015
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(4,307)	$369,944	$(479,424)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	1,556	8,276	79,339
(Gain) on derivatives not designated as hedges	—	(30)	(7,367)
Net cash received in settlement of derivative instruments	—	—	54,274
Impairment	2,486	1,583	452,037
Exploration costs	—	—	7,404
Embedded derivative	—	(5,538)	—
Amortization of leasehold costs	—	67	32,209
Share based compensation (non-cash)	240	3,307	6,689
Gain on sale of assets	—	(840)	(53,451)
Gain on extinguishment of debt	—	—	(62,555)
Amortization of finance cost and debt discount	1,518	7,425	12,415
Reorganization items	(6,658)	(410,875)	—
Material inventory write-down	—	—	1,168
Amortization of transportation obligation	—	156	469
Change in assets and liabilities:			
Accounts receivable, trade and other, net of allowance	(1,408)	724	11,573
Accrued oil and natural gas revenue	1,065	(786)	11,707
Inventory	—	(265)	(5,822)
Prepaid expenses and other	(66)	811	785
Accounts payable	1,631	(4,332)	(70,993)
Accrued liabilities	(384)	13,689	(7,468)
Net cash used in operating activities	(4,327)	(16,684)	(17,011)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(3,232)	(3,789)	(118,407)
Proceeds from sale of assets	849	294	113,533
Net cash used in investing activities	(2,383)	(3,495)	(4,874)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments of bank borrowings	(23,742)	—	(332,500)
Proceeds from bank borrowings	—	13,000	238,500
Proceeds from equity offering, net of issuance costs	23,622	—	47,480
Proceeds from Second Lien Notes	40,000	—	100,000
Note conversions	—	(804)	(434)
Debt issuance costs	—	(114)	(4,027)
Preferred stock dividends	—	—	(14,861)
Other	—	(5)	(499)
Net cash provided by financing activities	39,880	12,077	33,659

Increase (decrease) in cash and cash equivalents	33,170	(8,102)	11,774
Cash and cash equivalents, beginning of period	3,680	11,782	8
Cash and cash equivalents, end of period	$36,850	$3,680	$11,782
Supplemental disclosures of cash flow information:			
Cash paid during the year for interest	$498	$1,656	$22,279
Cash paid during the year for taxes	$—	$—	$—

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY/(DEFICIT)
(In Thousands)

Predecessor Company	Preferred Stock Shares	Preferred Stock Value	Common Stock Shares	Common Stock Value	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Value	Retained Earnings/ (Deficit)	Total Stockholders' Equity/(Deficit)
Balance at January 1, 2015	2,259	$2,259	45,105	$9,021	$1,066,770	—	$—	$(1,093,824)	$ (15,774)
Net loss	—	—	—	—	—	—	—	(479,424)	(479,424)
Employee stock plans	—	—	870	174	6,515	—	—	—	6,689
Note conversions	—	—	5,209	1,042	15,595	—	—	—	16,637
Preferred stock exchange	(757)	(757)	—	—	(94,923)	—	—	—	(95,680)
Director stock grants	—	—	249	50	635	—	—	—	685
Repurchases of stock	—	—	—	—	—	(173)	(41)	—	(41)
Equity offering	—	—	12,000	2,400	45,080	—	—	—	47,480
Preferred stock conversions	—	—	477	95	(149)	—	—	—	(54)
Warrant issuance	—	—	—	—	17,473	—	—	—	17,473
Convertible note issuance	—	—	—	—	12,677	—	—	—	12,677
Dividends	—	—	—	—	—	—	—	81,247	81,247
Balance at December 31, 2015	1,502	1,502	63,910	12,782	1,069,673	(173)	(41)	(1,492,001)	(408,085)
Net loss	—	—	—	—	—	—	—	369,944	369,944
Preferred stock dividends	—	—	—	—	—	—	—	4,112	4,112
Preferred stock conversion	(9)	(9)	6,102	1,220	(5,322)	—	—	—	(4,111)
Share based compensation	—	—	—	—	6,115	—	—	—	6,115
Warrant issuance	—	—	—	—	403	—	—	—	403
Equity offering	—	—	—	—	—	—	—	—	—
Director shares issued	—	—	—	—	—	—	—	—	—
Treasury stock activity	—	—	146	29	(29)	(47)	(5)	—	(5)
Convertible note issuance	—	—	—	—	—	—	—	—	—
Note conversions	—	—	9,818	1,964	29,663	—	—	—	31,627
Balance at October 12, 2016	1,493	$1,493	79,976	$15,995	$1,100,503	(220)	$(46)	$(1,117,945)	$ —
Cancellation of predecessor equity	(1,493)	(1,493)	(79,976)	(15,995)	(1,100,503)	221	46	1,117,945	—
Balance at October 12, 2016 Predecessor	—	—	—	—	—	—	—	—	—
Successor Company									
Issuance of common stock and warrants	—	—	6,836	68	30,312	—	—	—	30,380
Net Loss	—	—	—	—	—	—	—	(4,307)	(4,307)

Share based compensation	—	—	—	—	240	—	—	—	240
Second Lien Warrants and Conversion	—	—	—	—	10,964	—	—	—	10,964
Equity offering	—	—	2,273	23	23,727	—	—	—	23,750
Issuance Cost	—	—	—	—	(127)	—	—	—	(127)
Balance at December 31, 2016 Successor	—	$—	9,109	$91	$65,116	—	$—	$(4,307)	$ 60,900

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
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NOTE 1—Description of Business and Management Plan

Goodrich Petroleum Corporation (together with its subsidiary, “we,” “our,” or the “Company”) is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in (i) Southwest Mississippi and Southeast Louisiana, which includes the Tuscaloosa Marine Shale Trend (“TMS”), (ii) Northwest Louisiana and East Texas, which includes the Haynesville Shale, and (iii) South Texas, which includes the Eagle Ford Shale Trend.

Emergence from Voluntary Reorganization under Chapter 11 of the Bankruptcy Code

On April 15, 2016 (the “Petition Date”), Goodrich Petroleum Corporation and its subsidiary Goodrich Petroleum Company, L.L.C. (the “Subsidiary”, and together with the Company, the “Debtors”) filed voluntary petitions (the “Bankruptcy Petitions” and, the cases commenced thereby, the “Chapter 11 Cases”) seeking relief under Chapter 11 of Title 11 of the United States Bankruptcy Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the Southern District of Texas, Houston Division (the “Bankruptcy Court”), to pursue a Chapter 11 plan of reorganization. The Company filed a motion with the Bankruptcy Court seeking joint administration of the Chapter 11 Cases under the caption In re Goodrich Petroleum Corporation, et al. (Case No. 16-31975). The Debtors received Bankruptcy Court confirmation of their joint plan of reorganization (the "Plan of Organization") on September 28, 2016 (the "Approval Date") and subsequently emerged from bankruptcy on October 12, 2016 (the "Effective Date"). Although the Company is no longer a debtor-in-possession, the Company was a debtor-in-possession until emergence on October 12, 2016. As such, aspects of the Company’s bankruptcy proceedings and related matters are described below in order to provide context and explain a part of our financial condition and results of operations for the period presented. The Company is accounting for the bankruptcy in accordance with Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 852, “Reorganizations. The Company filed a series of first day motions with the Bankruptcy Court that allowed it to continue to conduct business without interruption. These motions were signed primarily to minimize the impact on the Company’s operations, customers and employees.

Prior to filing the Chapter 11 Cases, on March 28, 2016, the Company entered into a Restructuring Support Agreement (the “Restructuring Support Agreement”) with certain holders of the Company’s 8.0% Second Lien Senior Secured Notes due 2018 (the “8.0% Second Lien Notes”) and 8.875% Second Lien Senior Secured Notes due 2018 (the “8.875% Second Lien Notes” and together with the 8.0% Second Lien Notes, the “Second Lien Notes”). The Restructuring Support Agreement set forth, subject to certain conditions, the commitment to and obligations of, on the one hand, the Debtors, and on the other hand, the certain holders, in connection with the restructuring of the Company’s Second Lien Notes, 3.25% Convertible Senior Notes due 2026 (the “2026 Notes”), 5.0% Convertible Senior Notes due 2029 (the “2029 Notes”), 5.0% Convertible Senior Notes due 2032 (the “2032 Notes”), 5.0% Convertible Exchange Senior Notes due 2032 (the “2032 Exchange Notes”), 8.875% Senior Notes due 2019 (“the 2019 Notes”), 5.375% Series B Cumulative Convertible Preferred Stock (“Series B Preferred Stock”), 10% Series C Cumulative Preferred Stock (“Series C Preferred Stock”), 9.75% Series D Cumulative Preferred Stock (“Series D Preferred Stock”), 10% Series E Cumulative Convertible Preferred Stock (“Series E Preferred Stock”) and the Company’s common stock, par value $0.20 per share, pursuant to the Company’s Joint Prepackaged Plan of Reorganization filed under Chapter 11 of the United States Bankruptcy Code on the Petition Date. On May 21, 2016, the Restructuring Support Agreement was terminated automatically pursuant to its terms as an Assumption Order approving the Restructuring Support Agreement was not entered by the Bankruptcy Court within thirty-five days of the Petition Date. See discussion on the Plan of Reorganization below.

As discussed above, during the pendency of the Chapter 11 Cases, we operated our business as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. On October 12, 2016, we completed our financial restructuring and emerged from Chapter 11 bankruptcy proceedings after completing all required actions and satisfying all remaining conditions as required by the Bankruptcy Court. Our financial statements reflect material adjustments related to our Plan of

Reorganization and the application of fresh start accounting guidance upon emergence.

Effects of the Bankruptcy Proceedings

The Chapter 11 Cases described above constituted an event of default that accelerated the Company's obligations under all of its outstanding debt instruments. The agreements governing the Company's debt instruments at the time provided that as a result of the Bankruptcy Petitions, the principal and interest due thereunder was immediately due and payable. However, any efforts to enforce such payment obligations under the Company's debt instruments were automatically stayed as a result of the

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Chapter 11 Cases, and the creditors' rights of enforcement in respect of the debt instruments was subject to the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court.
On April 18, 2016, the Bankruptcy Court issued certain additional interim and final orders with respect to the Debtors' first-day motions and other operating motions that allowed the Debtors to operate their businesses in the ordinary course. Subject to certain exceptions under the Bankruptcy Code, the filing of the Bankruptcy Petitions automatically enjoined, or stayed, the continuation of any judicial or administrative proceedings or other actions against the Debtors or their property to recover, collect or secure a claim arising prior to the filing of the Bankruptcy Petitions. Thus, for example, most creditor actions to obtain possession of property from the Debtors, or to create, perfect or enforce any lien against the Debtors' property, or to collect on monies owed or otherwise exercise rights or remedies with respect to a pre-petition claim were enjoined.
During the Chapter 11 Cases, the Company conducted normal business activities and was authorized to continue to pay and has paid (subject to limitations applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders, critical vendors and other third parties, such as royalty holders and partners.

On July 25, 2016 the Company entered into and filed a motion with the Bankruptcy Court to approve a commitment letter (the "Commitment Letter") with a group of investors for the new issuance of 13.50% Convertible Senior Secured Second Lien Notes in the initial aggregate principal amount of $40.0 million (the "Convertible Second Lien Notes"). The Bankruptcy Court approved the motion on August 4, 2016 which allowed the Company to submit a revised plan of organization to the Bankruptcy Court. The approval by the Bankruptcy Court of the Commitment Letter terminated the bid procedures that were previously approved by the Bankruptcy Court on July 1, 2016.

The Commitment Letter provided for the issuance of $40.0 million in Convertible Second Lien Notes that mature on the later of August 30, 2019 or six months after the maturity of the Exit Credit Agreement (including all amendments, the "Exit Credit Facility"), discussed below. Interest on the Convertible Second Lien Notes will accrue at a rate of 13.50% per annum and be paid quarterly in cash or paid in kind by adding to the principal at the option of the issuer. The Convertible Second Lien Notes will convert at the option of the purchaser into a number of common shares equal to 15% of the common stock of the reorganized company. Upon closing, purchasers of the Convertible Second Lien Notes (i) were issued 10-year costless warrants for common stock equal to 20% of the new common stock of the reorganized company, (ii) took a second priority lien on all assets of the reorganized company, and (iii) received the right to appoint two members to the Board of Directors (the "Board") of the reorganized company. A total of $20.0 million in proceeds from the issuance of the Convertible Second Lien Notes were used to repay amounts outstanding under the existing Second Amended and Restated Credit Agreement (including all amendments, the "Senior Credit Facility") and $20.0 million in proceeds will be used to fund the Company's Haynesville Shale Trend drilling program.
On the Effective Date, upon consummation of the Plan of Organization, the Company entered into an Exit Credit Agreement (the "Exit Credit Agreement") with the Subsidiary, as borrower (the "Borrower"), and Wells Fargo Bank, National Association, as administrative agent ("the Administrative Agent"), and certain other lenders party thereto. Pursuant to the Exit Credit Agreement, the lenders party thereto have agreed to provide the Borrower with a $20.0 million senior secured term loan credit facility, with an outstanding principal amount of $20.0 million.

Plan of Reorganization
The significant features of the Plan of Reorganization confirmed by the Bankruptcy Court are as follows:

1. Each holder of an allowed priority claim (other than a priority tax claim or administrative claim) received either: (a) cash equal to the full allowed amount of its claim or (b) such other treatment as may otherwise be agreed to by such holder, the Debtors, the holders of at least 50% in principal amount of the Second Lien Notes (the "Majority

Consenting Noteholders”), and the purchasers of the new Convertible Second Lien Notes (“New 2L Notes Purchasers”);

2. Each holder of a secured claim (other than a priority tax claim, Senior Credit Facility claim, or Second Lien Notes claim) received, at the Debtors’ election and with the consent of the Majority Consenting Noteholders, either: (a) cash equal to the full allowed amount of its claim, (b) reinstatement of such holder’s claim, (c) the return or abandonment of the collateral securing such claim to such holder, or (d) such other treatment as may otherwise be agreed to by such holder, the Debtors, the Majority Consenting Noteholders, and the New 2L Notes Purchasers;

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3. The Senior Credit Facility claims were paid cash in an amount sufficient to reduce the Senior Credit Facility claims to a balance of $20.0 million while the remaining $20.0 million owed was to be refinanced into a new senior secured term loan credit facility;

4. The Second Lien Notes claims were deemed allowed in the aggregate amount of $175.0 million of principal plus accrued and unpaid interest through the Petition Date. Except to the extent a holder of a Second Lien Note claim agreed in writing to less favorable treatment, in full and final satisfaction, settlement, release, and discharge of, and in exchange for, each Second Lien Notes claim, each holder of a Second Lien Notes claim received their pro rata share of 98% of the new equity interests in the reorganized company (the “New Equity Interests”), subject to dilution on account of (i) the management incentive plan, (ii) the potential conversion of the Convertible Second Lien Notes, (iii) the warrants granted to the New 2L Notes Purchasers, and (iv) the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million;

5. Holders of unsecured notes claims received, pro rata with holders of other general unsecured claims, their pro rata share of the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million; plus its pro rata share of 2% of the New Equity Interests that are subject to dilution on account of (i) the management incentive plan, (ii) the potential conversion of the Convertible Second Lien Notes, (iii) the warrants granted to the New 2L Notes Purchasers, and (iv) the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal of $230.0 million;

6. Holders of allowed general unsecured claims had the option to elect on their ballot to (a) receive, pro rata with holders of unsecured notes claims, its pro rata share of the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million; plus its pro rata share of 2% of the New Equity Interests that are subject to dilution on account of (i) the management incentive plan, (ii) the potential conversion of the Convertible Second Lien Notes, (iii) the warrants granted to the New 2L Notes Purchasers, and (iv) the out-of-the-money warrants equal to an aggregate of up to 10% of the New Equity Interests with a maturity of 10 years and an equity strike price equal to $230.0 million, or (b) treat its allowed general unsecured claim as a convenience class claim by releasing any claims in excess of $10,000;

7. Holders of convenience class claims received either: (a) cash equal to the full allowed amount of such holder’s claim or (b) such lesser treatment as may otherwise be agreed to by such holder, the Debtors, the Majority Consenting Noteholders and the New 2L Notes Purchasers;

8. Equity interests in the Subsidiary were canceled and extinguished without further notice to, approval of, or action by any entity, and each holder of an equity interest in the Subsidiary did not receive any distribution or retain any property on account of such equity interest in the Subsidiary. Equity interests in the Company were canceled and extinguished without further notice to, approval of, or action by any entity, and each holder of an equity interest in the Company did not receive any distribution or retain any property on account of such equity interest in the Company.

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NOTE 2—Summary of Significant Accounting Policies

Basis of Presentation

During the pendency of the Chapter 11 Cases, we operated our business as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. ASC 852-10 applies to entities that have filed a petition for bankruptcy under Chapter 11 of the Bankruptcy Code. The guidance requires that transactions and events directly associated with the reorganization be distinguished from the ongoing operations of the business. In addition, the guidance provides for changes in the accounting and presentation of liabilities, as well as expenses and income directly associated with the Chapter 11 Cases.

In accordance with accounting principles generally accepted in the United States (“US GAAP”), we have applied ASC 852 “Reorganizations”, in preparing our consolidated financial statements. ASC 852 requires that the financial statements, for periods subsequent to the filing of the Bankruptcy Petitions, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain expenses, realized gains and losses and provisions for losses that are realized or incurred in the Chapter 11 Cases are recorded in “Reorganization items, net” in the accompanying Consolidated Statements of Operations.

While operating as debtors-in-possession under Chapter 11 of the Bankruptcy Code, we could sell or otherwise dispose of or liquidate assets or settle liabilities in amounts other than those reflected in our consolidated financial statements, subject to the approval of the Bankruptcy Court or otherwise as permitted in the ordinary course of business. Further, the Plan of Reorganization materially changed the amounts and classifications in our historical consolidated financial statements.

Fresh Start Accounting—We applied fresh start accounting upon emergence from bankruptcy on the Effective Date. This resulted in the Company becoming a new entity for financial reporting purposes. Upon adoption of fresh start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date. The Effective Date fair values of our assets and liabilities differed from the recorded values of our assets and liabilities as reflected in our consolidated financial statements as of October 12, 2016. The related adjustments were recorded in our consolidated statement of operations as reorganization items for the period April 15, 2016 to October 12, 2016 (Predecessor Company).

As a result, our consolidated balance sheets and consolidated statement of operations subsequent to the Effective Date will not be comparable to our consolidated balance sheets and statements of operations prior to the Effective Date. Our consolidated financial statements and related footnotes are presented in a format that illustrates the lack of comparability between amounts presented on or after October 12, 2016 and dates prior. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material.

References to the Successor relate to the Company on and subsequent to the Effective Date. References to the Predecessor refer to the Company prior to the Effective Date. The consolidated financial statements of the Successor have been prepared assuming that the Company will continue as a going concern and contemplate the realization of assets and the satisfaction of liabilities in the normal course of business.

Principles of Consolidation—The consolidated financial statements of the Company included in this Annual Report on Form 10-K have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC") and in accordance with US GAAP. The consolidated financial statements include the financial statements of Goodrich Petroleum Corporation and its wholly-owned subsidiary. Intercompany balances and transactions have been eliminated in consolidation. The consolidated financial statements reflect all normal recurring adjustments that, in the opinion of management, are necessary for a fair presentation. Certain data in prior period financial statements have been adjusted to conform to the presentation of the current period. We have evaluated subsequent events through the date of this filing.

Use of Estimates—Our Management has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with US GAAP.

Cash and Cash Equivalents—Cash and cash equivalents include cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at date of purchase.

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Accounts Payable—Accounts payable consists of $2.0 million in trade accounts payable for amounts due vendors, $10.9 million in revenue payable for amounts due to royalty and working interest owners, $1.3 million due to joint interest owners and $0.2 million due on severance taxes and other.
We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated.

Inventory –Inventory consists of casing and tubulars that are expected to be used in our capital drilling program and oil in storage tanks. Inventory is carried on the Consolidated Balance Sheets at the lower of cost or market.

Property and Equipment--Transition from Successful Efforts Method to Full Cost Accounting Method--Under U.S. Generally Accepted Accounting Principles ("GAAP"), two acceptable methods of accounting for oil and gas properties are allowed. These are the Successful Efforts Method and the Full Cost Method. Entities engaged in the production of oil and gas have the option of selecting either method for application in the accounting for their properties. The principal differences between the two methods are in the treatment of exploration costs, the computation of DD&A expense and the assessment of impairment of oil and gas properties.

Prior to October 12, 2016, we followed the Successful Efforts Method of Accounting for exploration and development expenditures. Under this method, costs of acquiring unproved and proved oil and natural gas leasehold acreage are capitalized. When proved reserves are found on an unproved property, the associated leasehold cost is transferred to proved properties. Significant unproved leases are reviewed periodically, and a valuation allowance is provided for any estimated decline in value. Costs of all other unproved leases are amortized over the estimated average holding period of the leases. Development costs are capitalized, including the costs of unsuccessful development wells. Additionally, oil and gas properties are assessed for impairment in accordance with Accounting Standards Codification 360.

Because a new entity has been created at the Effective Date, and there is no comparability to the predecessor company financial statements (see Note 3), upon emergence from bankruptcy we elected to adopt the Full Cost Method of Accounting. We believe that the true cost of developing a “portfolio” of reserves should reflect both successful and unsuccessful attempts at exploration and production. Application of the Full Cost Method of accounting will better reflect the true economics of exploring for and developing our oil and gas reserves. Therefore, as of October 12, 2016, we have used the Full Cost Method to account for our investment in oil and gas properties in the reorganized company.
Under the Full Cost Method, we will capitalize all costs associated with acquisitions, exploration, development and estimated abandonment costs. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, but do not include any costs related to production, general corporate overhead or similar activities. Unevaluated property costs are excluded from the amortization base until we make a determination as to the existence of proved reserves on the respective property or impairment. We review our unevaluated properties at the end of each quarter to determine whether the costs should be reclassified to proved oil and gas properties and thereby subject to DD&A and the full cost ceiling test. Our sales of oil and gas properties are accounted for as adjustments to net proved oil and gas properties with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.
We amortize our investment in oil and gas properties through DD&A expense using the units of production (the “UOP”) method. This entails the quarterly provision for DD&A expense being computed by dividing production volumes for the period by the total proved reserves as of the beginning of the period (beginning of period reserves being determined by adding production to the end of period reserves), and applying the respective rate to the net cost of

proved oil and gas properties and future development costs.

Full Cost Ceiling Test--The Full Cost Method requires that at the conclusion of each financial reporting period, the present value of estimated future net cash flows from proved reserves (adjusted for hedges and excluding cash flows related to estimated abandonment costs), be compared to the net capitalized costs of proved oil and gas properties, net of related deferred taxes. This comparison is referred to as a "ceiling test". If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows. Estimated future net cash flows from proved reserves are calculated based on a 12-month average pricing assumption.

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The Full Cost Ceiling Test performed as of December 31, 2016 resulted in recording a $2.5 million write-down of the Successor oil and gas properties.

Exploration- Prior to October 12, 2016, we followed the Successful Efforts Method of Accounting. Under Successful Efforts Method of Accounting exploration expenditures, including geological and geophysical costs, delay rentals and exploratory dry hole costs were expensed as incurred. Costs of drilling exploratory wells were initially capitalized pending determination of whether proved reserves can be attributed to the discovery. If management determined that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells were expensed. We had no capitalized exploratory well costs that were pending the determination of proved reserves as of December 31, 2015.

Fair Value Measurement— Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset should reflect its highest and best use by market participants, whether in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of nonperformance, which includes, among other things, our credit risk.

We use various methods, including the income approach and market approach, to determine the fair values of our financial instruments that are measured at fair value on a recurring basis, which depend on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. For some of our instruments, the fair value is calculated based on directly observable market data or data available for similar instruments in similar markets. For other instruments, the fair value may be calculated based on these inputs as well as other assumptions related to estimates of future settlements of these instruments. We separate our financial instruments into three levels (levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the fair value of our instruments. Our assessment of an instrument can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of the instruments between levels.

Each of these levels and our corresponding instruments classified by level are further described below:

- Level 1 Inputs— unadjusted quoted market prices in active markets for identical assets or liabilities. Included in this level is our senior notes;
- Level 2 Inputs—quotes which are derived principally from or corroborated by observable market data. Included in this level are our Senior Credit Facility and commodity derivatives whose fair values are based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our creditworthiness or that of our counterparties; and
- Level 3 Inputs—unobservable inputs for the asset or liability, such as discounted cash flow models or valuations, based on our various assumptions and future commodity prices. Included in this level would be acquisitions and impairments of oil and natural gas properties, our 2032 Exchange Notes, 8.0% Second Lien Notes, the embedded derivative associated with the 8.0% Second Lien Notes and 8.875% Second Lien Notes.

As of December 31, 2016, the carrying amounts of our cash and cash equivalents, trade receivables and payables represented fair value because of the short-term nature of these instruments.

Impairment — Prior to October 12, 2016 under the Successful Efforts Method of Accounting, we periodically assess our long-lived assets recorded in oil and natural gas properties on the Consolidated Balance Sheets to ensure that they were not overstated or carried in excess of fair value, which was computed using level 3 inputs such as discounted cash flow models or valuations. Significant level 3 assumptions associated with discounted cash flow models or valuations used in the impairment evaluation include estimates of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. An evaluation is performed on a field-by-field basis at least annually or whenever changes in facts and circumstances indicate that our oil and natural gas properties may be impaired.

To determine if a field is impaired, we compared the carrying value of the field to the undiscounted future net cash flows by applying management's estimates of proved reserves, future oil and natural gas prices, future production of oil and natural gas reserves and future operating costs over the economic life of the property. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions and the availability of capital to develop

proved undeveloped reserves. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the field.
Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depletion, depreciation and amortization to reduce the carrying value of the field. Each part of this calculation is subject to a large degree of judgment, including the determination of the fields' estimated reserves, future cash flows and fair value.

As of October 12, 2016, we had interests in oil and natural gas properties totaling $63.8 million, net of accumulated depletion, which we had accounted for under the successful efforts method. The expected future cash flows used for impairment reviews and related fair-value calculations are based on judgmental assessments of future production volumes, prices, and costs, considering all available information at the date of review. Due to the uncertainty inherent in these factors, we cannot predict when or if additional future impairment charges will be recorded. We estimate future net cash flows generated from our oil and natural gas properties using forecasted oil and natural gas prices published by the New York Mercantile Exchange ("NYMEX").

In the third and fourth quarters of 2015, the average NYMEX 5-year forward strip pricing for oil and natural gas had significantly decreased compared to year end 2014. The declines in commodity prices was an indication that the carrying amount of certain of our oil and natural gas properties may not be recoverable from future cash flows. Our impairment analysis in the third quarter of 2015 resulted in the recording a $32.5 million impairment on certain of our natural gas properties, which reduced the impaired fields' carrying value to an estimated fair value of $7.8 million at the end of the third quarter. During the fourth quarter of 2015, NYMEX forward 5-year strip oil prices continued to decline by an average of 16% and natural gas strip prices continued to decline by an average of 6%. The price declines in the fourth quarter of 2015 resulted in recording an additional impairment of $419.6 million on both our oil and natural gas properties. The $419.6 million impairment recognized in the fourth quarter of 2015 reduced the carrying value of the impaired fields to an estimated fair value of $63.4 million as of December 31, 2015. In the aggregate we recorded $452.0 million of impairments during 2015. We recorded a $1.6 million impairment on the carrying value of our materials inventory on October 12, 2016 reducing our carrying value to $4.1 million on October 12, 2016.

Depreciation —Depreciation and depletion of producing oil and natural gas properties is calculated using the units-of-production method. Proved developed reserves are used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves are used for unamortized leasehold costs.

Depreciation of furniture, fixtures and equipment, consisting of office furniture, computer hardware and software and leasehold improvements, is computed using the straight-line method over their estimated useful lives, which vary from three to five years.

Asset Retirement Obligations—Asset retirement obligations are related to the abandonment and site restoration requirements that result from the exploration and development of our oil and gas properties. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Accretion expense is included in "Depreciation, depletion and amortization" on our Consolidated Statements of Operations.

The estimated fair value of the Company's asset retirement obligations at inception is determined by utilizing the income approach by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the measurement of the asset retirement obligations was classified as Level 3 in the fair value hierarchy.

Revenue Recognition—Oil and natural gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Revenues from the production of crude oil and natural gas properties in which we have an interest with other producers are recognized using the entitlements method. We record a liability or an asset for natural gas balancing when we have sold more or less than our working interest share of natural gas production, respectively. At December 31, 2016 and 2015, the net liability for natural gas balancing was immaterial. Differences between actual production and net working interest volumes are routinely adjusted.

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Derivative Instruments—We use derivative instruments such as futures, forwards, options, collars and swaps for purposes of hedging our exposure to fluctuations in the price of crude oil and natural gas and to hedge our exposure to changing interest rates. Accounting standards related to derivative instruments and hedging activities require that all derivative instruments subject to the requirements of those standards be measured at fair value and recognized as assets or liabilities in the balance sheet. We offset the fair value of our asset and liability positions with the same counterparty for each commodity type. Changes in fair value are required to be recognized in earnings unless specific hedge accounting criteria are met. We have not designated any of our derivative contracts as hedges; accordingly, changes in fair value are reflected in earnings.

Income Taxes—We account for income taxes, as required, under the liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We recognize, as required, the financial statement benefit of an uncertain tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority.

Earnings Per Share—Basic income or loss per common share is computed by dividing net income or loss available to common stockholders for each reporting period by the weighted-average number of common shares outstanding during the period. Diluted income or loss per common share is computed by dividing net income or loss available to common stockholders for each reporting period by the weighted average number of common shares outstanding during the period, plus the effects of potentially dilutive stock options and restricted stock calculated using the Treasury Stock method and the potential dilutive effect of the conversion of shares associated with Series B Preferred Stock, Series E Preferred Stock, 2026 Notes, 2029 Notes, 2032 Notes and the 2032 Exchange Notes.

Commitments and Contingencies—Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties, and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. Recoveries from third parties, when probable of realization, are separately recorded and are not offset against the related environmental liability.

Concentration of Credit Risk—Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. The revenues compared to our total oil and natural gas revenues from the top purchasers for the years ended December 31, 2016, and 2015 are as follows:

	Year Ended December 31,

	2016	2015
Genesis Crude Oil LP	44 %	26 %
Sunoco, Inc.	30 %	17 %
Occidental Energy MA	13 %	— %
BP Energy Company	— %	31 %

Share-Based Compensation—We account for our share-based transactions using the fair value as of the grant date and recognize compensation expense over the requisite service period. The fair value of each restricted stock award is measured using the closing price of our common stock on the day of the award.

Guarantee- As of the December 31, 2015 Goodrich Petroleum Company LLC, the wholly owned subsidiary of Goodrich Petroleum Corporation was the Subsidiary Guarantor of all our outstanding notes which included, the 8.875% Senior Notes due

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2019, the 3.25% Convertible Senior Notes due 2026, the 5.0% Convertible Senior Notes due 2029, the 5.0% Convertible Senior Notes due 2032. the 5.0% Convertible Exchange Notes due 2032, the 8.0% Second Lien Senior Secured Notes due 2018 and the 8.875% Second Lien Senior Secured Notes due 2018. On October 12, 2016, the obligations of the Company with respect to the all the notes listed above were canceled and the holders receive common stock of the reorganized company pursuant to the Plan of Reorganization. See Note 6.

New Accounting Pronouncements

On March 30, 2016, the FASB issued ASU 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. The amendments in this ASU are intended to improve the accounting for employee share-based payments and affect all organizations that issue share-based payment awards to their employees. Several aspects of the accounting for share-based payment award transactions are simplified, including: (a) income tax consequences; (b) classification of awards as either equity or liabilities; and (c) classification on the statement of cash flows. For public entities, the amendments are effective for annual periods beginning after December 15, 2016. Our adoption of this ASU will be effective in January 2017. We do not anticipate an impact on our financial statements until the fourth quarter of 2017, as that is when the initial vestings of restricted stock issued under our Management Incentive Plan occur.

On February 25, 2016 the FASB issued ASU 2016-02, Leases (Topic 842). The key difference between the existing standards and ASU 2016-02 is the requirement for lessees to recognize on their balance sheet all lease contracts with lease terms greater than 12 months, including operating leases. Specifically, lessees are required to recognize on the balance sheet at lease commencement, both: (i) a right-of-use asset, representing the lessee’s right to use the leased asset over the term of the lease; and, (ii) a lease liability, representing the lessee’s contractual obligation to make lease payments over the term of the lease. For lessees, ASU 2016-02 requires classification of leases as either operating or finance leases, which are similar to the current operating and capital lease classifications. However, the distinction between these two classifications under the ASU does not relate to balance sheet treatment, but relates to treatment and recognition in the statements of income and cash flows. Lessor accounting is largely unchanged from current US GAAP. The amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, for public entities. Early application is permitted. We are currently evaluating the provisions of this ASU and assessing the impact it may have on our consolidated financial statements.

In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update (“ASU”) 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes, which seeks to simplify the presentation of deferred income taxes. The amendments in this update require that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. For public business entities, the amendments in this update are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted as of the beginning of an interim or annual reporting period. The amendments in this update may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. We adopted this standard in 2016 with no material impact on our financial statements. Prior period presentations have been adjusted to conform to the application of the standard.

In April 2015, the FASB issued ASU 2015-03, Interest-Imputation of Interest, which seeks to simplify presentation of debt issuance costs. The ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. Entities should apply the amendments in this ASU on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance. For public entities, this ASU is effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period. We adopted the provisions of this ASU in 2016. As a result, we reclassified prior year amounts within our Consolidated Balance Sheets to conform to the current year presentation.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers . ASU 2014-09 will supersede most of the existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which it expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires disclosures that are sufficient to enable users to understand an entity's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In March 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus

Net) . This update provides clarifications in the assessment of principal versus agent considerations in the new revenue standard. In May 2016, the FASB issued ASU 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow Scope Improvements and Practical Expedients. The update reduces the potential for diversity in practice at initial application of Topic 606 and the cost and complexity of applying Topic 606. In May 2016, the FASB issued ASU 2016-11, Revenue Recognition and Derivatives and Hedging: Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting. This update rescinds certain SEC Staff Observer comments that are codified in Topic 605, Revenue Recognition, and Topic 932, Extractive Activities-Oil and Gas, effective upon adoption of Topic 606. These ASUs are effective for annual and interim periods beginning after December 15, 2017. We are assessing the impact that the adoption of these standards will have on our consolidated financial statements.

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NOTE 3—Fresh Start Accounting

Our Plan of Reorganization was approved by the Bankruptcy Court on September 28, 2016. Subsequently, we emerged from Chapter 11 bankruptcy on October 12, 2016. Upon our bankruptcy emergence, we were subject to the requirements of FASB ASC 852, "Reorganizations". This included evaluating our ability to adopt "Fresh Start Accounting" and determining the reorganization value of our post-emergence company. Additional information pertaining to our Plan of Reorganization and bankruptcy emergence is contained in Note 1 to these Consolidated Financial Statements.

We qualified for the adoption of Fresh-Start Accounting because (1) the holders of existing voting shares of the pre-emergence debtor-in-possession, referred to herein as the "Predecessor" or "Predecessor Company" received less than 50% of the voting shares of the post-emergence successor entity, referred to herein as the "Successor" or "Successor Company", that were outstanding after our bankruptcy emergence and (2) immediately prior to the approval of our reorganization plan, the reorganization value of the "Predecessor"Company's assets was less than the allowed claims and post-petition liabilities. Our adoption of fresh start reporting resulted in our becoming a new reporting entity for financial reporting purposes, with no beginning retained earnings or deficit. On October 13, 2016, we began to apply fresh start accounting as a new entity. Our post emergence financial statements are therefore presented on this basis. Upon our application of fresh start accounting, we allocated our reorganization value to our individual assets based on their estimated fair values. Reorganization value represents the fair value of the Successor Company's assets before considering liabilities. Application of fresh start accounting and the effects of the implementation of our Plan of Reorganization resulted in our Consolidated Financial Statements on or after October 12, 2016 not being comparable with the Consolidated Financial Statements prior to that date. All references made regarding "Successor" or "Successor Company" relate to the financial position and results of operations of our reorganized entity subsequent to October 12, 2016. References to "Predecessor" or "Predecessor Company" refer to the financial position and results of operations of our entity prior to October 12, 2016.

Reorganization Value

Reorganization value was determined at our emergence date of October 12, 2016. It represents the fair value of the Successor Company's total assets and is intended to approximate the amount a willing buyer would pay for assets immediately after restructuring. We estimated the Successor Company asset value to be approximately $115 million inclusive of the $20 million net cash effect of the proceeds from the 2nd Lien Note. The valuation analysis was prepared with standard valuation techniques, which included a development plan, pricing models and discounting methods, and various other analytics. Information pertaining to reserves, inventory, fixed assets and other financial projections and information were used in the valuation analysis.

Proved Reserves

The Company determined the fair value of its proved producing oil and gas properties based upon the discounted cash flows expected to be generated from the properties. The valuation used New York Mercantile Exchange ("NYMEX ") WTI pricing for oil and Henry Hub pricing for natural gas. The after tax cash flows were discounted at 10.2%. This discount factor was derived from a weighted average cost of capital computation which utilized a blended expected cost of debt and expected returns on equity for similar industry participants. The cash flows were not risked since the properties consisted only proved producing properties.

Undeveloped Acreage

The Company owns undeveloped lease acreage in three major shale trends. The acreage is valued on a per acre basis reflecting recent acreage transactions within each trend.

Materials Inventory

The Company maintains an inventory of mostly tubular which is valued by market quote.

Asset Retirement Obligation

The Company has asset retirement obligations to plug and abandon wells at the end of their life. The company determines the Fair value of the obligation from quotes obtained from vendors for plug and abandonment cost which is escalated using 2.4% inflation factor and discounted using a credit adjusted risk free rate of 7.5%. The fair value is initially recorded as an asset and liability.

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Tangible Personal and Real Property

The company owns furniture, fixtures, computer equipment, software and fee land which is valued using the direct cost approach.

Current Assets

The company valued the current assets at book value due to their short term nature and includes the net cash effect of the 2nd Lien Note proceeds.

The following table reconciles the estimated fair value of the Successors Company assets at October 12, 2016 (in thousands):

	October 12, 2016
Current assets	$28,216
Oil & gas properties	
Proved Reserves	37,200
Undeveloped acreage	41,570
Asset Retirement Obligation	2,896
Materials inventory	4,125
Tangible personal & real property	984
Goodwill	9
Total asset value	$115,000
Balance sheet reclass (current assets)	18,201
Total successor assets	$96,799

Consolidated Balance Sheet

The information and adjustments set forth in the following consolidated balance sheet reflect our recent financial progression, beginning with that of our pre-emergence (Predecessor Company) and concluding with our current entity position (Successor Company). The completion of transactions as provided in our Plan of Reorganization are presented as "Reorganization Adjustments" and the fair value adjustments which resulted from our application of Fresh Start Accounting are specified as being "Fresh Start Adjustments." The explanatory notes emphasize methods used to determine fair values or other amounts of the assets and liabilities as well as significant assumptions.

The following table reflects the reorganization and application of ASC 852 on our consolidated Balance Sheet as of October 12, 2016 (in thousands):

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	Predecessor Company October 12, 2016	Reorganization Adjustments		Fresh Start Adjustments		Successor Company October 13, 2016
ASSETS						
Current assets:						
Cash and cash equivalents	$ 3,680	$ —		$ —		$ 3,680
Accounts receivable, trade and other, net of allowance	590	—		—		590
Accrued oil and gas revenue	4,207	—		—		4,207
Inventory	4,178	—		—		4,178
Prepaid expenses and other	1,161	—		—		1,161
Total current assets	13,816	—		—		13,816
Property and equipment						
Unevaluated oil & gas properties (Full Cost Method)	—	—		41,570	(5)	41,570
Evaluated oil & gas properties (Full Cost Method)	—	—		40,104	(5)	40,104
Oil and gas properties (successful efforts method)	976,021	—		(976,021)	(5)	—
Furniture, fixtures and equipment	7,302	—		(6,318)	(5)	984
	983,323	—		(900,665)		82,658
Less: Accumulated depletion, depreciation and amortization	(919,121)			919,121	(5)	—
Net property and equipment	64,202	—		18,456		82,658
Other	325	—		—		325
	325	—		—		325
Total Assets	78,343	$ —		$ 18,456		96,799
LIABILITIES AND STOCKHOLDERS' EQUITY						
Current liabilities:						
Accounts payable	12,761	—		—		12,761
Accrued liabilities	10,368	—		—		10,368
Accrued abandonment costs	83	—		(83)	(6)	—
Current portion of debt	40,393	—		—		40,393
Total current liabilities	63,605	—		(83)		63,522
Long-term debt	—	—		—		—
Accrued abandonment cost	3,861	—		(965)	(6)	2,896
Liabilities subject to compromise	426,249	(426,249)	(1)	—		—
Total liabilities	493,715	(426,249)		(1,048)		66,418
Stockholders' equity:						
Preferred stock, Series E	3	(3)	(2)	—		—
Preferred stock, Series D	4	(4)	(2)	—		—
Preferred stock, Series C	3	(3)	(2)	—		—
Preferred stock, Series B	1,483	(1,483)	(2)	—		—
Common stock (Predecessor)	15,995	(15,995)	(2)	—		—
Common stock (Successor)	—	68	(3)	—		68
Treasury Stock	(46)	46	(2)	—		—

Additional paid in capital (Predeccessor)	1,100,504	(1,100,504)	(2)	—		—
Additional paid in capital (Successor)		30,313	(3)	—		30,313
Retained earnings (Accumulated deficit)	(1,533,318)	1,513,814	(4)	19,504	(7)	—
Accumulated other comprehensive loss	—	—		—		—
Unamortized restricted stock awards	—	—		—		—
Total stockholders' equity (deficit)	(415,372)	426,249		19,504		30,381
Total Liabilities and Stockholders' Equity	78,343	—		18,456		96,799

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1. Liabilities subject to compromise were settled as follows in accordance with the Plan of Reorganization (in thousands):

8.0% Second Lien Senior Secured Notes due 2018	$100,000
8.875% Second Lien Senior Secured Notes due 2018	75,000
8.875% Senior Notes due 2019	116,828
3.25% Convertible Senior Notes due 2026	429
5.0% Convertible Senior Notes due 2029	6,692
5.0% Convertible Senior Notes due 2032	99,238
5.0% Convertible Exchange Senior Notes due 2032	6,305
Accrued interest	17,161
Accounts payable and accrued liabilities	4,596
Liabilities Subject to compromise at October 12, 2016	426,249
Fair value of equity in Successor Company	30,381
Gain on settlement of Liabilities subject to compromise	$395,868

2. Reflects the cancellation of the Predecessor Company Preferred and Common Stock and associated Additional Paid in Capital.

3. Reflects the issuance of 5.8 million shares of common stock to the Second Lien Noteholders, 0.1 million shares of common stock to the unsecured debt holders, and an issued 1.0 million common shares under the Management Incentive Plan. Additionally, the unsecured debt holders were issued warrants to purchase 1.3 million shares of common stock valued at $2.5 million.

4. Reflects the cumulative impact of the reorganization adjustments discussed above (in thousands):

Gain on settlement of Liabilities subject to compromise	$395,868
Cancellation of Predecessor Company equity	(1,513,814)
Net impact to accumulated deficit	$(1,117,946)

5. The following table summarizes the fair value adjustment on our oil and gas properties and accumulated depletion, depreciation and amortization (in thousands):

	Predecessor Company October 12 2016	Fresh Start Adjustments	Successor Company October 13, 2016
Oil and Gas Properties			
Oil & gas properties (successful efforts method)	$ 868,703	$ (868,703)	$ —
Unproved properties (successful efforts method)	107,318	(107,318)	—
Proved properties (Full Cost Method)	—	40,104	40,104
Unproved properties (Full Cost Method)	—	41,570	41,570
Total Oil and Gas Properties	976,021	(894,347)	81,674
Less: Accumulated depletion and impairments	(912,252)	912,252	—
Net Oil and Gas Properties	63,769	17,905	81,674

Furniture, Fixtures and other equipment	7,302	(6,318)	984
Less: Accumulated depreciation	(6,869)	6,869	—
Net Furniture, Fixtures and other equipment	433	551	984
Net Oil and Gas Properties, Furniture, and fixtures and accumulated depreciation	$ 64,202	$ 18,456	$ 82,658

6. Reflects the adjustment of Asset Retirement Obligation to fair value at the effective date.

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7. Reorganization Items represent items directly related to the Chapter 11 bankruptcy filing and implementation of the Plan of Reorganization and are classified as Gain on reorganization, net in the Consolidated Statement of Operations. The following table summarizes the reorganization items (in thousands):

	Successor	Predecessor
	Period from October 13, 2016 through December 31, 2016	Period from January 1, 2016 through October 12, 2016
Gain on settlement of liabilities subject to compromise	$ —	$ (395,868)
Gain on Fresh start adjustments	—	(19,504)
Professional fees and adjustments to debt	(130)	15,950
Gain on Reorganization items, net	$ (130)	$ (399,422)

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NOTE 4—Share-Based Compensation Plans

Overview

We emerged from Chapter 11 on October 12, 2016, at which time we also canceled our 2006 Long Term Incentive Plan, as amended in 2015. The 2006 Long Term Incentive Plan provided for grants to officers, employees and non-employee directors of compensation in the form of restricted stock and options. Upon cancellation of the 2006 Long Term Incentive Plan, no awarded options were outstanding, while 2.2 million non-vested restricted stock awards remained outstanding with a related $2.8 million in unamortized expense. All outstanding awards were canceled with the unamortized expense recorded to Gain on reorganization items, net on the Predecessor period Consolidated Statements of Operations.

We measure the cost of stock based compensation based on the fair value of the award as of the grant date, net of estimated forfeitures. Awards granted are valued at fair value and recognized on a straight-line basis over the service periods (or the vesting periods) of each award. We estimate forfeiture rates for all unvested awards based on our historical experience.

Management Incentive Plan (Successor Company)

The Confirmation Order related to our Chapter 11 Reorganization Plan approved a Management Incentive Plan (the "MIP") which provides for awards of restricted stock, option, performance awards, phantom shares and stock appreciation rights to directors, officers, employees, and consultants. The MIP initially provided for the issuance of 1.0 million shares of common stock, all of which were granted on October 12, 2016 pursuant to the Plan of Reorganization.

In December 2016, an additional 0.9 million shares, with a grant date fair value of $12.00, were awarded and will vest over a service period of up to 3 years except for grants to Directors which vest over 12 months.

The Management Incentive Plan is intended to promote the interests of the Company by providing a means by which employees, consultants and directors may acquire or increase their equity interest in the Company and may develop a sense of proprietorship and personal involvement in the development and financial success of the Company, and to encourage them to remain with and devote their best efforts to the business of the Company, thereby advancing the interests of the Company and its stockholders. The Management Incentive Plan is also intended to enhance the ability of the Company and its Subsidiary to attract and retain the services of individuals who are essential for the growth and profitability of the Company.

The Management Incentive Plan provides that the Compensation Committee shall have the authority to determine the participants to whom stock options, restricted stock, performance awards, phantom shares and stock appreciation rights may be granted.

The following tables summarizes the pretax components of our share-based compensation programs recorded, recognized as a component of general and administrative expenses in the Consolidated Statements of Operations (in thousands):

Management Incentive Plan	Year Ended December 31,

	2016	2015
Restricted stock expense	$ 187	$ —
Stock option expense	—	—
Director stock expense	53	—
Total share-based compensation:	$ 240	$ —

Restricted stock awarded under the MIP Plan typically have a vesting period of one to three years. During the vesting period, ownership of restricted stock shares subject to the vesting period cannot be transferred and the shares are subject to forfeiture if employment ends before the end of the vesting period. Certain restricted stock awards provide for accelerated vesting. Restricted shares are not considered to be currently issued and outstanding until the restrictions lapse and/or they vest.

Management Incentive Plan	Number of Shares Granted	Value of Shares Granted	Fair Value of Stock Vested
		(thousands)	(thousands)
2016	1,859,570	$ 14,365	$ 2,944

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Restricted stock activity and changes under our new Management Incentive Plan for the period October 12, 2016 to December 31, 2016, are reflected in the tables below:

Management Incentive Plan	Number of Shares	Weighted Average Grant-Date Fair Value	Total Value
			(thousands)
Unvested at October 12, 2016	—	—	—
Granted	1,859,570	$ 7.72	$ 14.365
Vested	(726,904)	4.05	2.944
Forfeited	—	—	—
Unvested at December 31, 2016	1,132,666	$ 10.08	$ 11.421

As of December 31, 2016, total unrecognized compensation cost related to restricted stock is as follows:

Management Incentive Plan	Unrecognized compensation costs	Weighted Average years to recognition
	(thousands)	(years)
December 31, 2016	$ 11,181	2.77

2006 Long Term Incentive Plan (Predecessor Company)

Upon our emergence from Chapter 11 on October 12, 2016, the 2006 Long Term Incentive Plan was canceled. The following tables summarizes the pretax components of our share-based compensation programs recorded, recognized as a component of general and administrative expenses in the Consolidated Statements of Operations (in thousands):

2006 Long-Term Incentive Plan	Period from January 1, 2016 through October 12, 2016	For the Year Ended December 31, 2015
Restricted stock expense	$ 3,307	$ 6,689
Stock option expense	—	—
Director stock expense	—	754
Total share-based compensation:	$ 3,307	$ 7,443

Stock Options

As discussed above, our 2006 Long Term Incentive Plan was canceled upon our bankruptcy emergence on October 12, 2016. The 2006 Long Term Incentive Plan provided that the option price of shares issued be equal to the market price on the date of grant. With the exception of option grants to non-employee directors, which vested immediately, options vested ratably on the anniversary of the date of grant over a period of time, typically three years. Our stock options expired in seven or ten years after the date of grant.

Option activity under our stock option plan as of October 12, 2016 and changes during the year through October 12, 2016 were as follows:

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	Shares	Weighted Average Exercise Price	Remaining Contractual Term	Aggregate Intrinsic Value
			(years)	(thousands)
Outstanding at January 1, 2016	60,000	$ 27.81	0.36	$ —
Granted	—	—	—	—
Exercised	—	—	—	—
Forfeited	(60,000)	—	—	—
Outstanding at October 12, 2016	—	$ —	—	$ —
Exercisable at October 12, 2016	—	$ —	—	$ —

The outstanding options had no intrinsic value as of December 31, 2015.

As of December 31, 2015, all compensation cost related to the stock options had been recognized in earnings. No stock options were granted in 2016 and as of October 12, 2016, there were no options outstanding due to the cancellation of the 2006 Long Term Incentive Plan.

Restricted Stock

Restricted stock awarded under the 2006 Long term Incentive Plan typically had a vesting period of three years. As discussed, all restricted stock awarded under the 2006 Long Term Incentive Plan was canceled. During the vesting period, ownership of restricted stock shares subject to the vesting period could not be transferred and the shares were subject to forfeiture if employment ended before the end of the vesting period. Certain restricted stock awards provide for accelerated vesting. Restricted shares are not considered to be currently issued and outstanding until the restrictions lapse and/or they vest.

Restricted stock activity and values under our plan for the period January 1, 2016 through October 12, 2016 and for the year ended December 31, 2015 were as follows:

2006 Long Term Incentive Plan	Number of Shares Granted	Value of Shares Granted	Fair Value of Stock Vested
		(thousands)	(thousands)
2016	126,891	$ 15	$ 24
2015	2,679,580	$ 2,525	$ 394

Upon our emergence from Chapter 11 on October 12, 2016, the 2006 Long Term Incentive Plan was canceled.

Restricted stock activity and changes under the prior 2006 Long Term Incentive Plan as of for the period January 1, 2016 to October 12, 2016, are reflected in the tables below:

2006 Long Term Incentive Plan	Number of Shares	Weighted Average Grant-Date Fair Value	Total Value
			(thousands)
Unvested at January 1, 2016	3,136.851	$ 2.25	$ 7,066

Granted	126.891	0.12	15
Vested	(924.816)	0.83	(768)
Forfeited	(160.507)	21.84	(3,505)
Canceled at October 12, 2016	2,178.419	$ 1.29	$ 2,808

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NOTE 5—Asset Retirement Obligations

The reconciliation of the beginning and ending asset retirement obligation for the periods ending December 31, 2016 and 2015 is as follows (in thousands):

	Successor	Predecessor	Predecessor
	October 13, 2016 to December 31, 2016	January 1, 2016 to October 12, 2016	Year ended December 31, 2015
Beginning balance	$ 2,897	$ 3,728	$ 6,510
Liabilities incurred	—	—	15
Revisions in estimated liabilities	—	—	—
Liabilities settled	—	—	(62)
Accretion expense	36	216	434
Dispositions (1)	—	—	(3,169)
Ending balance	$ 2,933	$ 3,944	$ 3,728
Current liability	$ —	$ 83	$ 83
Long term liability	$ 2,933	$ 3,861	$ 3,645

(1) The majority of the 2015 dispositions represent the divestiture of our producing Eagle Ford Shale Trend properties.

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NOTE 6—Debt

Debt consisted of the following balances as of the dates indicated (in thousands):

	Successor December 31, 2016			Predecessor December 31, 2015		
	Principal	Carrying Amount	Fair Value	Principal	Carrying Amount (5)	Fair Value (1)
Exit Credit Facility (7)	$16,651	$16,651	$16,651	$ —	$ —	$ —
13.50% Convertible Second Lien Term Loan (8)	41,170	30,554	29,036	—	—	—
Senior Credit Facility	—	—	—	27,000	25,387	27,000
8.0% Second Lien Senior Secured Notes due 2018 (2) (6)	—	—	—	100,000	87,529	14,512
8.875% Second Lien Senior Secured Notes due 2018 (6)	—	—	—	75,000	91,364	7,586
8.875% Senior Notes due 2019 (6)	—	—	—	116,828	115,599	9,346
3.25% Convertible Senior Notes due 2026 (6)	—	—	—	429	429	64
5.0% Convertible Senior Notes due 2029 (3) (6)	—	—	—	6,692	6,692	67
5.0% Convertible Senior Notes due 2032 (4) (6)	—	—	—	98,664	95,882	6,923
5.0% Convertible Exchange Senior Notes due 2032 (6)	—	—				