GOODRICH PETROLEUM CORP
Form 10-K
March 02, 2018

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, 2017
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	NYSE American
(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, a smaller reporting company, or emergency growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	¨	Accelerated filer	o
Non-accelerated filer	¨	Smaller reporting company	x
Emerging growth company	¨		

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

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 $0.01 per share, held by non-affiliates (based upon the closing sales price on the NYSE American on June 30, 2017, the last business day of the Registrant's most recently completed second fiscal quarter) was approximately $46.6 million. The number of shares of the Registrant's common stock par value $0.01 per share, outstanding as of March 1, 2018 was 11,359,887.

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 ý 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, 2017

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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 165 producing oil and natural gas wells located in 38 fields in seven states. At December 31, 2017, we had estimated proved reserves of approximately 428 Bcfe, comprised of 415 Bcf of natural gas and 2.1 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.

Emergence from Voluntary Reorganization under Chapter 11 of the Bankruptcy Code

On April 15, 2016, 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 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 Debtors received Bankruptcy Court confirmation of their joint plan of reorganization on September 28, 2016 and subsequently emerged from bankruptcy on October 12, 2016 (the “Effective Date”).

The Company accounted for the bankruptcy in accordance with Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 852, “Reorganizations”.

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 calculated in accordance with United States Generally Accepted Accounting Principles ("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, 2017, nearly all of our proved oil and natural gas reserves were located in Louisiana, Texas and Mississippi. We spent substantially all of our 2017 capital expenditures of $41.8 million in the Haynesville Shale Trend of Northwest Louisiana. Our total capital expenditures, including accrued costs for services performed during 2017, consisted of $41.2 million for drilling and completion costs, $0.5 million for leasehold acquisitions and extensions, and $0.1 million for furniture and fixtures.

We are currently focused on developing our Haynesville Shale Trend assets. The Haynesville Shale Trend is one of the top natural gas plays in the U.S., particularly when factoring in its geographic location, pipeline and infrastructure capacity and deliverability of gas to the gulf coast industrial complex and liquified natural gas export facilities. As a result, substantially all of our 2018 capital expenditure budget is planned for Haynesville Shale Trend development.

The table below details our acreage positions, average working interest and producing wells as of December 31, 2017.

Field or Area	Acreage As of December 31, 2017 Gross	Net	Average Producing Well Working Interest		Producing wells at December 31, 2017
Tuscaloosa Marine Shale Trend	87,635	64,945	65	%	40
Haynesville Shale Trend	50,097	25,855	33	%	91
Eagle Ford Shale Trend	32,430	14,148	—		—
Other	33,125	7,323	23	%	34

Haynesville Shale Trend

As of December 31, 2017, we have acquired or farmed-in leases totaling approximately 50,100 gross (25,900 net) acres in the Haynesville Shale Trend. During 2017, we added 5 gross (1.5 net) wells to production on our acreage. Our Haynesville Shale Trend drilling activities are currently located in leasehold areas in Caddo, DeSoto and Red River parishes, Louisiana. As of December 31, 2017, we had 6 gross wells in the drilling phase and 5 additional gross wells waiting on completion operations in the Haynesville Shale Trend.

On February 28, 2018, we closed, in two separate transactions, the sale of working interests in certain oil and gas leases, wells, units and facilities (the "Disposition") and certain net leasehold interests in a portion of our undeveloped acreage in the Angelina River Trend in Angelina and Nacogdoches Counties, Texas to BP America Production Company for total consideration of approximately $23 million, with an effective date of January 1, 2018. The Disposition is subject to customary post-closing adjustments.

Tuscaloosa Marine Shale Trend

As of December 31, 2017, we have acquired approximately 87,600 gross (64,900 net) lease acres in the TMS, an oil shale play in Southwest Mississippi and Southeast Louisiana. Approximately 60,400 gross (41,900 net) acres are currently held by production. During 2017, we did not conduct any drilling operations and did not add any wells to production. As of December 31, 2017, we had 2 gross (1.7 net) wells waiting on completion operations in the TMS.

Eagle Ford Shale Trend

As of December 31, 2017, we have acquired or farmed-in leases totaling approximately 32,400 gross (14,100 net) lease acres in the Eagle Ford Shale Trend. We sold our Eagle Ford Shale Trend proved reserves and a portion of the associated leasehold on September 4, 2015 but retained approximately 14,100 net acres of undeveloped leasehold in Frio County, Texas for future development or sale.

Other

As of December 31, 2017, 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 Haynesville Shale Trend, TMS 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, 2017 and 2016, 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, 2017 on properties other than those located in the TMS. RSC prepared the estimate of proved reserves as of December 31, 2017 for our TMS properties. Copies of the summary reserve reports of NSAI and RSC as of December 31, 2017 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.

Net proved reserves and the PV10 estimates at December 31, 2017 below, were calculated using flat, twelve month average commodity index prices of $51.34 per barrel and $2.98 per Mmbtu.

	Proved Reserves at December 31, 2017			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	1,414	716	—	2,130
Natural Gas (Mmcf)	40,841	12,020	362,363	415,224
Mcf Natural Gas Equivalent (Mmcfe) (2)	49,326	16,313	362,363	428,002
Estimated Future Net Cash Flows				$500,504
PV-10 (3)				$264,159
Discounted Future Income Taxes				(3,849)
Standardized Measure of Discounted Net Cash Flows (3)				$260,310

	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 (Mmcfe) (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

(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.

The following table presents our reserves by targeted geologic formation in Mmcfe:

	December 31, 2017			
Area	Proved Developed	Proved Undeveloped	Proved Reserves	% of Total
Tuscaloosa Marine Shale Trend	12,704	—	12,704	3 %
Haynesville Shale Trend	48,960	362,363	411,323	96 %
Other	3,975	—	3,975	1 %
Total	65,639	362,363	428,002	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

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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 2017 through December 2017, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For reserves at December 31, 2017, the average twelve month prices used were $2.98 per MMBtu of natural gas and $51.34 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, 2017 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, 2017, as estimated by NSAI and RSC, were 428 Bcfe, consisting of 415 Bcf of natural gas and 2.1 MMBbls of oil and condensate. In 2017 we added approximately 33 Bcfe related to our drilling activities in the Haynesville Shale Trend. We had positive revisions of approximately 105 Bcfe and produced 12 Bcfe in 2017. We are employing new completion techniques on our Haynesville Shale Trend wells which have been proven on the successful producing wells we drilled in 2017 and 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 Trend reserves as of December 31, 2017.

Our proved undeveloped ("PUD") reserves at December 31, 2017, all in our Haynesville Shale Trend, were 362 Bcfe, or 85% of our total proved reserves. In 2017, we had net positive revisions of previous estimates of 84 Bcfe and new additions of 33 Bcfe. We developed approximately 13 Bcfe, or 5% of our total proved undeveloped reserves booked as of December 31, 2016, through the drilling of 4 gross (2.3 net) development wells. Of the proved undeveloped reserves in our December 31, 2017 reserve report, the oldest was initially booked on December 31, 2016. Consequently, none have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves, and none are scheduled for commencement of development on a date more than five years from the date the reserves were initially booked as proved undeveloped.

The positive PUD revision of previous estimates attributable to ever improving well completion technology and techniques was 47 Bcf. We increased our ownership in the well locations by negotiating acreage swaps with offset operators which added 22 Bcf and commodity price increases added 15 Bcf to PUD reserves.

We suffered a delay in our development well program in the second half of 2017 primarily related to the prolific hurricane events in our operating area. We had 13 gross (5.9 net) development wells waiting to be completed.

Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2017:

	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	23	14	—	—	23	14
Haynesville Shale Trend:						
East Texas	—	—	6	5	6	5
Northwest Louisiana	—	—	91	30	91	30
Other	9	1	19	5	28	6
Total Productive Wells	49	27	116	40	165	67

(1) Royalty and overriding interest wells that have immaterial values are excluded from the above table. As of December 31, 2017, only two 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.

Acreage

The following table summarizes our gross and net developed and undeveloped acreage under lease as of December 31, 2017. 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	28,369	19,981	9,560	5,459	37,928	25,440
Southeast Louisiana	32,053	21,919	17,653	17,586	49,706	39,505
Haynesville Shale Trend:						
East Texas	12,553	7,181	212	371	12,765	7,553
Northwest Louisiana	36,665	18,362	1,961	573	38,626	18,935
Eagle Ford Shale Trend:						
South Texas	11,185	7,457	21,244	6,691	32,430	14,148
Other	27,195	6,004	4,637	686	31,832	6,690
Total	148,020	80,904	55,267	31,366	203,287	112,271

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, 2017:

Year	Net Acreage
2018	22,492
2019	1,961
2020	8,284
2021	56

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 portion of our 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, 2017 Gross	2017 Net	2016 Gross	2016 Net	2015 Gross	2015 Net
Development Wells:						
Productive	5	1.5	2	0.4	8	6.7
Non-Productive	—	—	—	—	—	—
Total	5	1.5	2	0.4	8	6.7
Exploratory Wells:						
Productive	—	—	—	—	—	—
Non-Productive	—	—	—	—	—	—
Total	—	—	—	—	—	—
Total Wells:						
Productive	5	1.5	2	0.4	8	6.7
Non-Productive	—	—	—	—	—	—
Total	5	1.5	2	0.4	8	6.7

At December 31, 2017, we had 13 gross (5.9 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, 2017), 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, 2017.

	Sales Volumes Natural Gas Mmcf	Sales Volumes Oil & Condensate MBbls	Total Mmcfe	Average Sales Prices (1) Natural Gas Mcf	Average Sales Prices (1) Oil & Condensate Per Bbl	Average Sales Prices (1) Total Per Mcfe	% of Total Revenue	Average Production Cost (2) Per Mcfe
For Year 2017 (Successor):								
TMS	—	302	1,813	$—	$ 50.86	$8.48	34 %	$ 3.92
Haynesville Shale Trend	10,303	—	10,303	2.88	—	2.88	66 %	0.47
Other	20	2	34	5.86	55.67	7.25	— %	3.84
Total	10,323	304	12,150	$2.89	$ 50.90	$3.73	100 %	$ 1.00
For Year 2016 (Pro Forma) (4):								
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 (Predecessor):								
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

(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.

(4) 2016 Pro Forma results is the combined Successor and Predecessor periods of 2016 as discussed earlier under "Emergence from Voluntary Reorganization under Chapter 11 of the Bankruptcy Code".

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, 2017, and pro forma full year 2016 are as follows:

	Year Ended December 31,	
	2017	2016 (Pro Forma)
Genesis Crude Oil LP	20%	44 %
Sunoco, Inc.	13%	30 %
Williams Energy Resources LLC	29%	— %
ETC	15%	4 %
Occidental Energy MA	7 %	13 %

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.

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 26, 2018 we had 44 employees in our Houston administrative office and 4 employees in our field offices, all of whom were full-time and none of whom was 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, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to the protection of the environment and natural resources. 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

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 strict, joint and several 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. If the EPA proposes a rulemaking for revised oil and natural gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. 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, the EPA and U.S. Army Corps of Engineers (the "Corps") finalized new rules defining the scope of the EPA's and the Corps' jurisdiction under the Clean Water Act. The 2015 rule was stayed nationwide to determine whether federal district or appellate courts had jurisdiction to hear cases in the matter and, in January 2017, the U.S. Supreme Court agreed to hear the case. The EPA and Corps proposed a rulemaking in June 2017 to repeal the June 2015 rule, announced their intent to issue a new rule defining the Clean Water Act's jurisdiction. Recently, in January 2018, the U.S. Supreme Court issued a decision finding that jurisdiction resides with the federal district courts; consequently, while implementation of the 2015 rule currently remains stayed, the previously-filed district court cases will be allowed to proceed. Following the Supreme Court's decision, the EPA and the Corps issued a final rule in January 2018 staying implementation of the 2015 rule for two years. As a result of these recent developments, future implementation of the June 2015 rule is uncertain. To the extent the June 2015 rule is implemented or any replacement rule expands the scope of the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. 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. Over the years, 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 ("CAA") governing air emission performance standards, including standards for the capture of volatile organic compounds and methane emissions released during 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. However, the BLM finalized a rule in December 2017 repealing its March 2015 hydraulic fracturing regulations. The repeal has been challenged in court and the final outcome is uncertain at this time.

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, and additional regulation of hydraulic fracturing at the federal level appears unlikely at this time.

While 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, the prospect of additional federal legislation related to hydraulic fracturing appears remote at this time. 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 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. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either "attainment/unclassifiable" or "unclassifiable". In December 2017, the EPA responded to states preliminary non-attainment designations, and expects to issue final non-attainment designations during the first half of 2018. 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 ("GHG"). 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. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards but the EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on federal and Indian lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the November 2016 final rule until January 17, 2019. The suspension of the November 2016 final rule is being challenged in court. These rules, should they remain in effect, or any other new methane emission standards imposed on the oil and gas sector, could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

Currently, federal legislation related to the reduction of greenhouse gas emissions appears unlikely; however, many states have established greenhouse gas cap and trade programs, and others are considering carbon taxes or initiatives that promote the use of alternative fuels and renewable sources of energy. 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. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. 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 extreme weather events. Such events could disrupt our operations or result in damage to our assets and 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 (“USFWS”) was required to make a determination on listing of numerous species as endangered or threatened under the ESA before the completion of the agency’s 2017 fiscal year. The USFWS did not complete the review by the deadline and continues to review species for protected status under the ESA. 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.

Oil and natural gas prices are volatile. A sustained decrease in the price of oil or natural gas would adversely impact our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commtments.

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 of oil. 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. During the period from January 1, 2014 to December 31, 2017, average daily prices for NYMEX Henry Hub natural gas ranged from a high of $6.15 per MMBtu to a low of $1.64 per MMBtu and NYMEX WTI oil prices ranged from a high of $107.26 per Bbl to a low of $26.55 per Bbl. The market for these products will likely continue to be volatile in the future. Our revenues, operating results, profitability and future growth are highly dependent on the prices we receive for our production, and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the supply and demand for oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the level of global inventories;
- prevailing prices on local price indices in the areas in which we operate and expectations about future commodity prices;
- the extent of natural gas production associated with increased oil production;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions across North America and, increasingly due to liquified natural gas, across the globe;
- technological advances affecting energy consumption;
- risks associated with operating drilling rigs;
- speculative trading in commodity markets;
- end user conservation trends;
- petrochemical, fertilizer, ethanol, transportation supply and demand balance;
- the price and availability of alternative fuels;
- domestic, local and foreign governmental regulation and taxes; and
- liquefied petroleum products supply and demand balances.

Changes in commodity prices significantly affect our capital resources, liquidity and expected operating results. Lower commodity prices will reduce our cash flows and borrowing ability and may require us to curtail exploration, drilling and production activity. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. Lower commodity prices may also reduce the amount of oil and natural gas that we can produce economically. We have historically been able to hedge our natural gas production at prices that are higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements may be limited. Additionally, declines in prices could result in 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,

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including the risk that no commercially productive oil or natural 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;
- 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.

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 and cash flows are subject to a number of variables, including:

- our proved reserves;
- the volume of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves;
- the extent and levels of our derivative activities;
- the levels of our operating expenses; and
- our ability to borrow under our 2017 Senior Credit Facility.

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, 2017, 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.

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. In addition, a significant amount of our common stock is owned by a limited number of holders, many of which received the shares that they own when we emerged from bankruptcy or in financing transactions following such emergence. We have filed registration rights agreements under which many of these holders may sell shares of our common stock. 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 2017. 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, 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, 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, worker health and safety aspects of our operations, or otherwise relating to the protection of the environment and natural resources. 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 has been 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. Over the years, 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 CAA governing performance standards, including standards for the capture of volatile organic compounds and methane emissions released during 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. However, the BLM finalized a rule in December 2017 repealing its March 2015 hydraulic fracturing regulations. The repeal has been challenged in court and the final outcome is uncertain at this time.

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 and additional federal regulation of hydraulic fracturing appears unlikely at this time.

While 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, the prospect of additional federal legislation related to hydraulic fracturing appears remote at this time. 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 CAA. 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. 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. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards but the EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on federal and Indian lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the November 2016 final rule until January 17, 2019. The suspension of the November 2016 final rule is being challenged in court. These rules, should they remain in effect, or any other new methane emission standards imposed on the oil and gas sector, could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

Currently, federal legislation related to the reduction of greenhouse gas emissions appears unlikely; however, many states have established greenhouse gas cap and trade programs, and others are considering carbon taxes or initiatives that promote the use of alternative fuels and renewable sources of energy. 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. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. 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 extreme weather events. Such weather events could disrupt our operations or result in damages to our assets and 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.

Post emergence from bankruptcy in 2016, the Successor company had an operating loss of $2.6 million and an operating loss of $2.2 million for the year 2017. 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.

Derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity prices, interest rates and other risks associated with our business.

The Dodd-Frank Act, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Commodity Futures Trading Commission (“CFTC”) has finalized certain of its regulations under the Dodd-Frank Act, but others remain to be finalized or implemented. It is not possible at this time to predict when this will be accomplished or what the terms of the final rules will be, so the impact of those rules is uncertain at this time.

The CFTC has designated certain types of swaps (thus far, only certain interest rate swaps and credit default swaps) for mandatory clearing and exchange trading, and may designate other types of swaps for mandatory clearing and exchange trading in the future. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we are availing ourselves of the end-user exception to the mandatory clearing and exchange trading requirements for swaps designed to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract market or swap executive facility.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from margin requirements for swaps to other market participants, such as swap dealers, these rules may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, we could be required to post initial or variation margin, which would impact liquidity and reduce our cash. This would in turn reduce our ability to execute hedges to reduce risk and protect cash flows.

The Dodd-Frank Act and any new 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 and reduce our ability to monetize or restructure our existing commodity price contracts. If we reduce our use of commodity price contracts as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make cash distributions to our unitholders. Further, to the extent our revenues are unhedged, they could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

Recently enacted changes to the U.S. federal tax laws could adversely affect our business, financial condition and results of operations.

Recently enacted legislation commonly referred to as the “Tax Cuts and Jobs Act” (the “TCJA”) includes significant changes to the taxation of business entities. These changes include, among others, a permanent reduction to the corporate income tax rate. Such rate reduction, however, could be offset by other changes intended to broaden the tax base (for example, by imposing new limitations on the utilization of net operating losses and the deduction of interest expense and eliminating the deduction for certain domestic production activities). While past legislative proposals have included changes to other U.S. federal income tax incentives available to oil and gas companies, including the elimination of the percentage depletion allowance for oil and gas properties, the elimination of current deductions for intangible drilling and development costs and an extension of the amortization period for certain geological and geophysical expenditures, those changes were not included in the TCJA. No accurate prediction can be made as to whether these or similar changes will be proposed or enacted in the future, and if enacted, how soon such changes would take effect. We continue to examine the impact the TCJA may have on us, and it could adversely affect our business, financial condition and results of operations.

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 had positive net cash settlements of $0.5 million during 2017.

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 9-“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.

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 natural 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 period ended October 12, 2016, the Predecessor Company recorded impairment related to oil and natural gas properties of $1.6 million. The decline in oil and natural gas prices precipitated the loss of estimated proved reserves for our oil and natural gas producing properties.

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. We had no impairment for the year ended December 31, 2017.

We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flows and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil and natural gas prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Decreased levels of drilling activity in the oil and natural gas industry in recent periods have led to declining costs of some drilling equipment, materials and supplies. However, such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flows and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

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, 2017 were associated with our Louisiana, Texas and Mississippi properties which include the Haynesville Shale Trend and TMS. 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.

Events of force majeure may limit our ability to operate our business and could adversely affect our operating results.

The weather, unforeseen events, or other events of force majeure in the areas in which we operate could cause disruptions and, in some cases, suspension of our operations. This suspension could result from a direct impact to our properties or result from an indirect impact by a disruption or suspension of the operations of those upon whom we rely for gathering and transportation. If disruption or suspension were to persist for a long period, our results of operations would be materially impacted.

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 of our properties in the Haynesville Shale Trend. As of December 31, 2017, approximately 51% of our reserves and approximately 37% 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. Although we have the ability to propose operations to 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. 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 years ended December 31, 2017 and 2016 were 84% and 91%, 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, 2017 and pro forma full year 2016 are as follows:

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	Year Ended December 31,	
	2017	2016 (Pro Forma)
Genesis Crude Oil LP	20 %	44 %
Sunoco, Inc.	13 %	30 %
Williams Energy Resources LLC	29 %	— %
ETC	15 %	4 %
Occidental Energy MA	7 %	13 %

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

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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 2017 Senior Credit Facility, which could result in an event of default under the 2017 Senior 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 Amended and Restated Senior Secured Revolving Credit Agreement, dated October 17, 2017, by and between the Subsidiary, as borrower, JPMorgan Chase Bank, N.A. as administrative agent, and certain lenders named therein (the “2017 Senior Credit Facility”), the Company and the Subsidiary are required to maintain certain financial covenants including the maintenance of (i) a ratio of Total Debt (as defined in the 2017 Senior Credit Facility) to EBITDAX not to exceed 4.00 to 1.00 as of the last day of any fiscal quarter, (ii) a current ratio (based on the ratio of current assets to current liabilities) not to be less than 1.00 to 1.00 and (iii) until no Convertible Second Lien Notes remain outstanding, (A) a ratio of Total Proved PV10% attributable to the Company’s and Subsidiary’s Proved Reserves (as defined in the 2017 Senior Credit Facility) to Total Secured Debt (net of any Unrestricted Cash not to exceed $10.0 million) not to be less than 1.50 to 1.00, (B) limitations on cash general and administrative expenses through 2017 of $10.1 million and (C) minimum liquidity requirements.

The 2017 Senior 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 2017 Senior 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 2017 Senior 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.

The exercise of all or any number of outstanding warrants or the issuance of share-based awards may dilute your holding of shares of our common stock.
As of February 28, 2018, we have outstanding (i) costless warrants granted to the Convertible Second Lien Notes Purchasers representing 0.5 million shares of our common stock, (ii) 1.0 million warrants exercisable into 1.4 million shares of the Company's common stock at an exercise price of $17.01 per share and (iii) 1.6 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.

Risk Relating to Our Emergence from Bankruptcy

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

It is possible that our bankruptcy and our 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 NYSE American. The market price of our common stock could be subject to wide fluctuations

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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 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. Due to the concentration of holdings of our common stock, 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.

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

Upon emergence from bankruptcy, the composition of our Board of Directors (our “Board”) changed considerably. Our Board is now made up of seven directors, of which five have not previously served on our Board prior to our emergence from bankruptcy. 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 (“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 (“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.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

A discussion of our current legal proceedings is set forth in Note 10—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 "Emergence from Voluntary Reorganization under Chapter 11 of the Bankruptcy Code" 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 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. On April 11, 2017, the Company's common stock commenced trading on the NYSE American under the symbol (“GDP”).

At March 1, 2018, the number of holders of record of our common stock was 52 and 11,359,887 shares were outstanding. High and low sales prices for our common stock for each quarter during 2017 and 2016 were as follows:

	2017		2016	
	High	Low	High	Low
First Quarter	$15.00	$13.00	$0.28	$0.05
Second Quarter	17.25	10.81	0.08	0.02
Third Quarter	14.37	8.20	0.05	0.01
Fourth Quarter	11.95	8.96	14.00	10.75

The over-the-counter market quotations for 2016 and through April 10, 2017 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 our 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, 2017.

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.

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.

Emergence from 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.

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"). 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 the Effective Date 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. Additional information pertaining to our adoption, application, and effects of fresh start accounting is contained in Note 2 to these Consolidated Financial Statements.

On the Effective Date, 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.

Business Strategy

Our business strategy is to provide long-term growth in reserves and cash flow on a cost-effective basis. We focus on maximizing our return on capital employed and adding reserve value through the timely development of our Haynesville Shale Trend acreage. We regularly evaluate possible acquisitions of prospective acreage and oil and natural gas drilling opportunities.

Several of the key elements of our business strategy are the following:

Develop existing property base. We seek to maximize the value of our existing assets by developing and exploiting our properties that we have identified as having the lowest risk and the highest potential rates of return. To accomplish this strategy, we currently intend to develop our multi-year inventory of drilling locations and natural gas reserves on our Haynesville Shale Trend acreage.

Increase our natural gas production. We have concentrated on increasing our natural gas production and reserves by investing and drilling in the Haynesville Shale Trend. We intend to take advantage of improved completion technology to significantly increase production volume and consequently reduce our per unit finding cost and operating expenses.

Expand acreage position in the Haynesville Shale Trend. As of December 31, 2017, we held approximately 25,900 net acres in the Haynesville Shale Trend. In addition to having significant experience in the play we intend to have significant operational control of our Haynesville Shale Trend assets. To leverage our extensive regional knowledge base, we seek to acquire leasehold acreage with significant drilling potential in areas that exhibit characteristics similar to our existing properties. We also continually strive to rationalize our portfolio of properties by selling marginal non-core properties in an effort to redeploy capital to exploitation, development and exploration projects that offer potentially higher overall returns.

Focus on maximizing cash flow margins. We intend to maximize operating cash flow by focusing on higher-margin natural gas development in the Haynesville Shale Trend. In the current commodity price environment, our Haynesville Shale Trend assets offer more attractive rates of return on capital invested and cash flow margins than our oil assets.

Maintain financial flexibility. As of December 31, 2017, we had $26.0 million in cash and a borrowing base of $40 million under our $250 million Amended and Restated Senior Secured Revolving Credit Agreement, dated October 17, 2017, by and between the Subsidiary, as borrower, JPMorgan Chase Bank, N.A. as administrative agent, and certain lenders named therein (the “2017 Senior Credit Facility”) on which we had $23.3 million available in borrowing capacity. We plan on funding growth primarily through operating cash flow. We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, including fixed price swaps and costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating results.

2017 Financial and Operating Results included:

- We incurred drilling or completion costs on 16 wells in the Haynesville Shale Trend. 11 gross wells are waiting completion as of December 31, 2017;
- We ended the year with 428 Bcfe of proved oil and natural gas reserves;
- We entered into the 2017 Senior Credit Facility with $23.3 million available at December 31, 2017;
- We became listed on the NYSE American under the symbol “GDP”;
- We exited 2017 with $26.0 million in cash.

Haynesville Shale Trend

Our relatively low risk development acreage in this trend is primarily centered in Caddo, DeSoto and Red River parishes, Louisiana and Angelina and Nacogdoches counties, Texas. We held approximately 50,100 gross (25,900 net) acres as of December 31, 2017 producing from or prospective for the Haynesville Shale Trend. We incurred drilling or completion costs on 16 gross (5.7 net) wells in 2017 spending $38.4 million of which $0.3 million was leasehold cost. Our net production volumes from our Haynesville Shale Trend wells represented approximately 85% of our total equivalent production on a Mcfe basis for 2017.

Tuscaloosa Marine Shale Trend

We held approximately 87,600 gross (64,900 net) acres in the TMS as of December 31, 2017 with approximately 60,400 gross (41,900 net) acres held by production. During 2016 and 2017, 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 15% of our total equivalent production on a Mcfe basis and approximately 99% of our total oil production for the year ended December 31, 2017. During 2017, we spent $0.4 million in the TMS, which included $0.2 million for leasehold costs.

Eagle Ford Shale Trend

As of December 31, 2017, we have retained approximately 14,100 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 the Effective Date. Prior to the Effective Date, the Predecessor used the Successful Efforts Method of Accounting. The results of 2017 and 2016 operations of the Successor are not generally comparable to the results of 2016 operations of the Predecessor. 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 2017.

The Predecessor 2016 Period results of operation reflects the period from January 1, 2016 to October 12, 2016. The net income of $370 million was primarily the result of the $399 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 million 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.

For the year ended December 31, 2017, the Successor reported a net loss of $8.0 million or $0.80 per (basic and diluted) share. The net loss was primarily the result of $3.4 million in workover expense incurred in our effort to reestablish production volumes and $4.5 million to reestablish our non-cash share-based compensation plan after emergence from bankruptcy.

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.

Summary Operating Information:	Successor Year Ended December 31, 2017	Successor October 13, to December 31, 2016	Predecessor January 1, 2016 to October 12, 2016	Pro Forma Year Ended December 31, 2016	Variance	
Revenues:						
Natural gas	$ 29,829	$ 2,327	$ 5,817	$ 8,144	$21,685	266 %
Oil and condensate	15,491	4,210	15,210	19,420	(3,929)	(20)%
Natural gas, oil and condensate	45,320	6,537	21,027	27,564	17,756	64 %
Net Production:						
Natural gas (Mmcf)	10,323	1,198	4,357	5,555	4,768	86 %
Oil and condensate (MBbls)	304	88	388	476	(172)	(36)%
Total (Mmcfe)	12,150	1,723	6,687	8,410	3,740	44 %
Average daily production (Mcfe/d)	33,288	21,538	23,381	22,979	10,309	45 %
Average Realized Sales Price Per Unit:						
Natural gas (per Mcf)	$ 2.89	$ 1.94	$ 1.34	$ 1.47	$1.42	97 %
Natural gas (per Mfc) including the effect of realized gains/losses on derivatives	$ 2.94	$ 1.97	$ 1.41	$ 1.47	$1.47	100 %
Oil and condensate (per Bbl)	$ 50.90	$ 47.84	$ 39.20	$ 40.80	$10.10	25 %
Oil and condensate (per Bbl) including the effect of realized gains/losses on derivatives	$ 50.61	$ 47.84	$ 39.20	$ 40.80	$9.81	24 %
Average realized price (per Mcfe)	$ 3.73	$ 3.79	$ 3.14	$ 3.28	$0.45	14 %

Oil and Natural Gas Revenue

Natural gas, oil and condensate revenues increased in 2017 compared to pro forma 2016 reflecting increases in our average realized sales prices for natural gas, oil and condensate and an increase in natural gas production offset by decreased oil and condensate production. The increases in natural gas, oil and condensate realized sales prices and in natural gas production contributed approximately $12.7 million and $13.8 million, respectively, to the increase in natural gas, oil and condensate revenue. Decreased oil and condensate production reduced natural gas, oil and condensate revenue by approximately $8.7 million compared to pro forma 2016.

The difference on a pro forma basis between our average realized prices inclusive of net cash derivative settlements for the year ended December 31, 2017 and pro forma 2016 relates to our oil and natural gas contracts. We had no natural gas or oil derivative contract settlements in 2016 while, in 2017, we had oil derivative settlements on 400 Bbls per day, only for the month of December 2017 at the fixed price of $51.08 per Bbl, and natural gas derivative settlements on a daily average of 15,008 Mmbtu with a weighted average put price of $3.49 per Mmbtu. We received $0.6 million in natural gas derivative settlements from our counterparties and paid our counterparties $0.1 million in oil derivative settlements in 2017.

Operating Expenses

(in thousands)	Successor Year Ended December 31, 2017	Successor October 13, to December 31, 2016	Predecessor January 1, 2016 to October 12, 2016	Pro Forma Year Ended December 31, 2016	Variance		
Lease operating expenses	$ 12,125	$2,109	$ 6,504	$ 8,613	$3,512	41	%
Production and other taxes	1,183	619	1,946	2,565	(1,382)	(54)	%
Transportation and processing	6,222	228	1,265	*	—	—	%
Exploration	—	—	577	*	—	—	%

Per Mcfe	Successor Year Ended December 31, 2017	Successor October 13, to December 31, 2016	Predecessor January 1, 2016 to October 12, 2016	Pro Forma Year Ended December 31, 2016	Variance		
Lease operating expenses	$ 1.00	$1.22	$ 0.97	$ 1.02	$(0.02)	(2)	%
Production and other taxes	0.10	0.36	0.29	0.30	(0.20)	(67)	%
Transportation and processing	0.51	0.13	0.19	*	—	—	%
Exploration	—	—	0.09	*	—	—	%

* Not comparable

Lease Operating Expense

Our lease operating expense (“LOE”) during 2017 increased compared to 2016 on a pro forma basis. LOE in 2017 included $3.4 million in workover expense, an increase of $2.2 million compared to 2016 LOE pro forma. The increases are attributed to workover operations in our Haynesville Shale Trend. Additionally, our LOE related to our TMS oil wells increased by $1.5 million in 2017 compared to 2016 pro forma driven by increased salt water disposal and production enhancement costs. The oil wells require more attention to maintain production as they age.

LOE on per unit basis decreased by $0.02 in 2017 compared to 2016 on a pro forma basis. We expect LOE on a per unit basis will continue to decrease as we bring Haynesville Shale Trend horizontal natural gas wells on line which carry much lower per unit operating cost than oil wells.

Production and Other Taxes

Production and other taxes for the year ended 2017 included production tax of $1.3 million and ad valorem tax credit of $0.1 million. Production taxes increased $0.3 million in 2017 compared to 2016 on a pro forma basis driven by expiration of our severance tax exemptions in Mississippi and Louisiana offset by $0.2 million in audit refunds. 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 is 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) payout of the well. The State of Louisiana has also enacted an exemption from the existing 12.5% severance tax on oil production and from the $0.098 per Mcf (through June 30, 2017) and $0.11 per Mcf (from July 1, 2017 through June 30, 2018) severance tax on natural gas production 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) payout of the well. The net revenues from our wells drilled in our TMS acreage in Southwestern Mississippi and Southeast Louisiana have been favorably impacted by these exemptions. The Louisiana Haynesville Shale Trend wells that we brought on line in 2017 and will bring on line in 2018 will receive the benefit of these tax exemptions.

Ad valorem tax in 2017 was a credit of $0.1 million as compared to a $1.6 million charge in 2016 on a pro forma basis. The decrease in ad valorem tax between periods reflects audit refunds of approximately $0.9 million recorded in 2017 as well as the reduction in the assessed values of our properties.

Transportation and Processing

Our natural gas production incurs substantially all of our transportation and processing cost. Transportation and processing for the year 2017 includes a $0.4 million non-recurring charge for infrastructure cost paid to our transporter to connect our wells for sales. Additionally, in 2017, we incurred higher transportation and processing rates on the natural gas volumes that we took in kind on non-operated Haynesville Shale Trend wells, which represented approximately 57% of our natural gas production in 2017, or $4.2 million. Prior to August 2016, the transportation and processing cost on these non-operated wells were netted against the Company's realized natural gas price under an agency agreement.

Transportation and processing average cost per unit should decrease as produced operated gas volumes increase as a result of our drilling program. Our operated natural gas volumes are less burdened with transportation cost than our non-operated natural gas volumes.

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 and the previously mentioned netting of the cost from the sales price.

Exploration

The Successor Company adopted the Full Cost Method of accounting as of the Effective Date resulting in exploration costs being capitalized to the full cost pool rather than expensed.

The Exploration expense in the Predecessor 2016 period consisted of $0.1 million cost of non-producing lease expirations, $0.2 million in delay rental payments and $0.3 million in geological and geophysical costs.

	Successor	Successor	Predecessor
(in thousands)	Year Ended December 31, 2017	October 13, to December 31, 2016	January 1, 2016 to October 12, 2016
Depreciation, depletion & amortization	$ 12,125	$ 1,556	$ 8,276
Impairment	—	2,486	1,583
General & administrative	16,696	2,200	14,474
Gain on sale of assets	—	(2)	(840)

	Successor	Successor	Predecessor
Per Mcfe	Year Ended December 31, 2017	October 13, to December 31, 2016	January 1, 2016 to October 12, 2016
Depreciation, depletion & amortization	$ 1.00	$ 0.90	$ 1.24
Impairment	—	1.44	0.24
General & administrative	1.37	1.28	2.16
Gain on sale of assets	—	—	(0.13)

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

DD&A expense in the 2017 Successor period was calculated on the Full Cost Method of Accounting. We adjust our DD&A rates twice a year in conjunction with issuance of our year-end and mid-year reserve reports. Included in DD&A for 2017 is the depletion of our oil and gas properties of $11.7 million, accretion of our Asset Retirement Obligation of $0.2 million and $0.2 million in depreciation of our furniture and fixtures.

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

DD&A expense in the 2016 Predecessor Period was calculated on the Successful Efforts Method of Accounting and reflects higher rates due to a higher asset base.

Impairment

Our Full Cost Ceiling Test performed quarterly did not require recording an impairment in 2017.

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.

General and Administrative Expense ("G&A")

General and Administrative Expense for the year ended December 31, 2017 includes $4.5 million in share-based compensation and $3.1 million of accrued performance bonus compensation which is expected to be paid in 2018 in a combination of cash and common stock. Our 2017 Senior Credit Facility and 13.50% Convertible Second Lien Senior Secured Notes due 2019 placed limitations on cash general and administrative expenses through 2017 of $10.1 million. G&A payable in cash, which excludes share-based compensation, accrued performance bonus to be compensated in stock and accrued rent expense, was $9.2 million for the year ended December 31, 2017. We capitalized $2.4 million of G&A directly attributed to our capital development to the full cost pool during 2017. With the exception of share-based compensation and accrued performance bonus increases, our G&A expense decreased in 2017 by approximately $3.6 million. It is expected that overall G&A expense will increase slightly due to salary and wage increases in 2018 but will decrease on a per unit of production basis due to production volume increases from our drilling and development program.

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 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 reflects our lower oil and natural gas production which increased per unit expenses.

Gain on Sale of Assets

No gain or loss was recognized for properties sold in 2017 or during the Successor period in 2016. In 2016, the Predecessor recognized $0.8 million gain on the settlement of the Eagle Ford Shale property escrow account related to the sale in 2015 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.

Other Income (Expense)

	Successor Year Ended December 31, 2017	Successor October 13, to December 31, 2016	Predecessor January 1, 2016 to October 12, 2016
Other Income (Expense):			
Interest expense	$ (9,725)	$ (1,824)	$ (11,398)
Interest income and other	1,236	1	117
Gain on derivatives not designated as hedges	1,552	—	30

Restructuring	—	—	(5,128)
Reorganization net gain	118	130	399,944
Income tax benefit	978	—	—
Average funded borrowings adjusted for debt discount	50,708	26,399	*
Average funded borrowings	60,314	59,503	*

* - Not Meaningful

Interest Expense

Interest expense in 2017 Successor period includes $1.2 million incurred on the 2017 Senior Credit Facility and Exit Credit Facility and $8.5 million incurred on the 13.5% Convertible Second Lien Senior Secured Notes due 2019 (the “Convertible Second Lien Notes”). The interest on the Convertible Second Lien Notes was all non-cash consisting of $5.9 million in paid-in-kind interest and amortized debt discount of $2.6 million.

Interest expense in the 2016 Successor period reflects the interest incurred on the Exit Credit Facility of $0.3 million and $1.5 million on the Convertible Second Lien Notes. The interest on the Convertible Second Lien Notes was all non-cash consisting of $1.2 million in paid-in-kind interest and amortized debt discount of $0.3 million.

The Predecessor Company's interest expense for the 2016 Predecessor period reflects interest payable in cash of $8.5 million and non-cash interest of $2.7 million. The Predecessor Company did not record interest expense subsequent to April 15, 2016 on any of its outstanding second lien and senior notes. All the accrued interest on such indebtedness was never paid as the underlying debt was canceled in bankruptcy.

Interest Income and Other

We recorded a credit of $1.2 million in interest income and other in 2017 primarily related to the receipt of cash that was previously held in escrow related to the sale of Predecessor's assets in a prior period.

Gain on Derivatives Not Designated as Hedges

We produce and sell oil and natural gas into a market where prices are historically volatile. We enter into swap contracts, collars or other derivative agreements from time to time to manage our exposure to commodity price risk for a portion of our production.

Gain on commodity derivatives not designated in the 2017 Successor period is comprised of an unrealized gain of $1.1 million and gain from net cash settlements $0.5 million. The unrealized gain represents a $2.6 million gain in the fair value of our natural gas derivative contracts offset by a $1.5 million loss in the fair value of our oil derivative contracts. The net gain on cash settlements reflects $0.6 million cash received on settlement of our natural gas derivatives offset by $0.1 million payment on the settlement on our oil derivatives.

The gain on commodity derivatives not designated as hedges was less than $0.1 million in 2016 Predecessor Period related to mark to market valuation on natural gas swap contracts. The contracts were canceled in bankruptcy. We had no derivatives in the 2016 Successor period.

Restructuring

As a result of the efforts to restructure the Company outside of bankruptcy early in 2016 and the subsequent preparation involved in filing the Chapter 11 Cases, we incurred significant professional fees and other costs totaling $5.1 million.

Reorganization items, net

The Successor Company in the 2016 Successor period and for the year 2017 realized gains on reorganization of $0.1 million in each period. We continue to work on settling bankruptcy claims. We anticipate that we will continue to incur professional and United States Bankruptcy Trustee fees until the bankruptcy case is final. We will record these fees in the period in which they are incurred. We believe that the estimated liability of $0.2 million we have established for the claims is sufficient to cover such costs.

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 the Effective Date. 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.

Income Tax Benefit

We recorded a $1.0 million income tax benefit for the year ended December 31, 2017 and no income tax benefit for the year ended December 31, 2016. We recorded a valuation allowance at December 31, 2016, which resulted in no net deferred tax asset or liability appearing on our statement of financial position. We recorded this valuation allowance after an evaluation of all available evidence (including our recent history of net operating losses in 2016 and prior years) that led to a conclusion that based upon the more-likely-than-not standard of the accounting literature, our deferred tax assets were unrecoverable. The income tax benefit recorded in 2017 is due to the projected refund of alternative minimum tax ("AMT") credits for which we also recorded a non-current deferred tax asset. Considering the Company's taxable income forecasts, our assessment of the realization of our deferred tax assets other than for the AMT credits has not changed, and we continue to maintain a full valuation allowance for our net deferred tax assets as of December 31, 2017.

On December 22, 2017, the United States enacted tax reform legislation known as the H.R.1, commonly referred to as the "Tax Cuts and Jobs Act" (the "Act"), resulting in significant modifications to existing law. The Company has completed the accounting for the effects of the Act during 2017. Our financial statements for the year ended December 31, 2017 reflect certain effects of the Act which includes a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018, as well as other changes.

Adjusted EBITDA/EBITDAX

Adjusted EBITDA/EBITDAX is a supplemental non-United States Generally Accepted Accounting Principle ("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. The Predecessor defined Adjusted EBITDAX as earnings before
interest expense, income and similar taxes, DD&A, exploration expense, share-based compensation expense and impairment of oil and natural gas properties. The Successor calculates Adjusted EBITDA in the same way, but EBITDA reflects the absence of
exploration expense in the Full Cost Method of Accounting used by the Successor. In calculating Adjusted EBITDA/ EBITDAX, gains on reorganization, gains/losses on commodity derivatives not designated as hedges and net cash received or paid in settlement of derivative instruments are also excluded. Other excluded items include interest income and any extraordinary non-cash gains or losses. 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:

	Successor Year Ended December 31, 2017	Successor October 13, to December 31, 2016	Predecessor January 1, 2016 to October 12, 2016
(In thousands)			
Net income (loss) (US GAAP)	$ (7,996)	$ (4,307)	$ 369,944
Depreciation, depletion and amortization	12,125	1,556	8,276
Income tax benefit	(978)	—	—
Exploration Expense	—	—	577
Impairment	—	2,486	1,583

Share-based compensation	6,863	240	3,307
Interest expense	9,725	1,824	11,398
Gain on reorganization	(118)	(130)	(399,422)
Gain on commodity derivatives not designated as hedges	(1,552)	—	(30)
Net cash received (paid) in settlement of derivative instruments	471	—	—
Other items (1)	(38)	(3)	(957)
Adjusted EBITDA/EBITDAX	$ 18,502	$ 1,666	$ (5,324)

(1) Other items include interest income and other, gain on sale of assets 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

Our primary sources of cash during 2017 were cash on hand, cash flow from operating activities, which includes a $1.2 million refund of escrowed funds related to the sale of our East Texas properties in 2014 and $0.7 million in ad valorem tax refunds, and cash from asset sale proceeds of $0.6 million. We used cash in 2017 primarily to fund our drilling and development capital program. In 2016, our primary sources of cash on and after the Effective Date 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.

On October 17, 2017, we entered into the 2017 Senior Credit Facility, which provides for revolving loans of up to the borrowing base then in effect. Total lender commitments under the 2017 Senior Credit Facility are $250 million subject to a borrowing base limitation, which as of December 31, 2017 was $40 million. The 2017 Senior Credit Facility matures on a) October 17, 2021 or b) if the Convertible Second Lien Notes have not been voluntarily redeemed, repurchased, refinanced or otherwise retired by September 30, 2019, September 30, 2019. Revolving borrowings under the 2017 Senior Credit Facility are limited to, and subject to periodic redeterminations, of the borrowing base. The amount of the borrowing base is determined by the lenders in their sole discretion and consistent with their oil and gas lending criteria at the time of the relevant redetermination. The initial borrowing base is $40 million. Pursuant to the terms of the 2017 Senior Credit Facility, borrowing base redeterminations will be on a semi-annual basis on or about March 1st and September 1st of each calendar year, commencing on or about March 1, 2018. The borrowing base is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. Additionally, we and the administrative agent may request one unscheduled redetermination of the borrowing base between scheduled redeterminations. JPMorgan Chase Bank, N.A. is the lead lender and administrative agent under the 2017 Senior Credit Facility.

During 2017, we generated $18.3 million in cash through operating activities ending the year with cash on hand of $26.0 million. As of December 31, 2017, we had $23.3 million available under the 2017 Senior Credit Facility. We are beginning the year 2018 with $49.3 million in immediately available capital resources.

On February 28, 2018, we closed, in two separate transactions, the sale of working interests in certain oil and gas leases, wells, units and facilities (the "Disposition") and certain net leasehold interests in a portion of our undeveloped acreage in the Angelina River Trend in Angelina and Nacogdoches Counties, Texas to BP America Production Company for total consideration of approximately $23 million, with an effective date of January 1, 2018. The Disposition is subject to customary post-closing adjustments.

Use of proceeds will be to pay off the Company's revolver and for potential acceleration of the Company's capital expenditure plans.

Outlook

Our total capital expenditures for 2018 are expected to be approximately $65 to $75 million with flexibility to increase or decrease this amount based on the movement of commodity prices. We plan to focus all of our capital on drilling and development of our Haynesville Shale Trend natural gas properties in North Louisiana, and we currently contemplate drilling and developing 16 gross (5.7 net) wells utilizing improved completion techniques.

We believe the results of the capital investments we made 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.

In addition, to support future cash flows, we entered into strategic derivative positions as of December 31, 2017, covering approximately 41% and 14% of our anticipated oil and natural gas sales volumes for 2018 and 2019, respectively. See Note 9-"Derivative Activities" in the Notes to consolidated Financial Statements in Part II Item 8 of the Annual Report on Form 10-K.

We continuously monitor our balance sheet and coordinate our capital program with our expected cash flows and scheduled debt repayments. We will continue to evaluate funding alternatives as needed.

Alternatives available to us include:
•issuance of equity securities;
•joint ventures in our TMS and/or Haynesville Shale Trend acreage;
•availability under the 2017 Senior Credit Facility; and
•sale of non-core assets.

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

Cash flow statement information:	Successor Year Ended December 31, 2017	Successor October 13, to December 31, 2016	Predecessor January 1, 2016 to October 12, 2016
Net Cash:			
Provided by (used in) operating activities	$ 18,306	$ (4,327)	$ (16,684)
Used in investing activities	(28,200)	(2,383)	(3,495)
Provided by (used in) financing activities	(964)	39,880	12,077
Increase (decrease) in cash and cash equivalents	$ (10,858)	$ 33,170	$ (8,102)

At December 31, 2017, we had positive working capital of $2.2 million and $55.7 million in long-term debt.

Cash Flows

For the Year Ended December 31, 2017

Operating activities: Net cash provided by operating activities for the Year Ended December 31, 2017 was $18.3 million. Production from our wells, the price of oil and natural gas and operating costs represent the main drivers of our cash flow from operations. In addition, net cash settlements of $0.5 million related to our derivative contracts and a $0.5 million change in working capital also positively impacted cash flows.

Investing activities: Net cash used in investing activities was $28.2 million for the year ended December 31, 2017. We booked $41.8 million in capital expenditures, of which we paid out cash amounts totaling $28.8 million for drilling and development operations in the period. The difference is attributed to utilizing $0.4 million of cash calls paid in previous period, utilized $1.8 million from materials inventory, capitalized $0.2 million in asset retirement obligation and a net $10.6 million increased in the capital expenditure accrual. The period also reflects the receipt of $0.6 million in proceeds from the sales of various non-producing mineral interests in non-core areas. We conducted drilling operations on 13 wells and completed 2 wells all in the Haynesville Shale Trend during the year ended December 31, 2017 capitalizing $2.4 million in internal costs.

Financing activities: Net cash used in financing activities for the year ended December 31, 2017 was $1.0 million consisting of $16.7 million payoff of the balance on the Exit Credit Facility, $0.3 million in registration and issuance costs associated with various securities issued since our emergence from bankruptcy or to be issued in the future, $0.7 million issuance cost incurred on the entering into the Amended and Restated Senior Secured Revolving Credit Facility offset by the $16.7 million in proceeds from that new credit facility.

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 Convertible 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 our 2017 Senior Credit Facility and Exit Credit Facility of $23.7 million.

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

	December 31, 2017			December 31, 2016		
	Principal	Carrying Amount	Fair Value	Principal	Carrying Amount	Fair Value
Exit Credit Facility (1)	$—	$—	$—	$16,651	$16,651	$16,651
2017 Senior Credit Facility (1)	16,723	16,723	16,723	—	—	—
Convertible Second Lien Notes (2)	47,015	39,002	62,026	41,170	30,554	29,036
Total debt	$63,738	$55,725	$78,749	$57,821	$47,205	$45,687

(1) The carrying amounts for the Exit Credit Facility and 2017 Senior Credit Facility represent fair value as they were fully secured.

(2) 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 paid-in-kind (PIK) interest as of December 31, 2016 and $7.0 million as of December 31, 2017. The carrying value includes $10.6 million and $8.0 million of unamortized debt discount at December 31, 2016 and 2017, respectively. The fair value of the notes was obtained by using a Binomial Lattice Model within Level 3 of the fair value hierarchy for the value on December 31, 2016 and utilized the last known sale price for the value on December 31, 2017.

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 periods ended:

	Successor			Successor			Predecessor	
	Year Ended December 31, 2017			Period from October 12, 2016 through December 31, 2016			Period from January 1, 2016 through October 12, 2016	
	Interest Expense	Effective Interest Rate		Interest Expense	Effective Interest Rate		Interest Expense	Effective Interest Rate
Senior Credit Facility	$—	—	%	$—	—	%	$3,342	*
Exit Credit Facility	947	7.1	%	306	7.3	%	—	— %
2017 Senior Credit Facility	244	7.2	%	—	—	%	—	— %
Convertible Second Lien Notes (1)	8,534	24.1	%	1,518	24.7	%	—	— %
Obligations Canceled on the Effective Date	—	—	%	—	—	%	8,010	*
Other	—	—	%	—	—	%	46	*
Total	$9,725			$1,824			$11,398	

* - Not comparative as the Company was in bankruptcy during portions of the 2016 periods shown and did not pay interest on its debt while in bankruptcy.

(1) Interest expense for the year ended December 31, 2017 includes $2.6 million of debt discount amortization and $5.8 million of paid in-kind interest.

Amended and Restated Senior Secured Revolving Credit Facility

On October 17, 2017, the Company entered into the 2017 Senior Credit Facility, which provides for revolving loans of up to the borrowing base then in effect (the "2017 Senior Credit Facility"). The 2017 Senior Credit Facility amends, restates and refinances the obligations under the Exit Credit Facility. The 2017 Senior Credit Facility matures (a) October 17, 2021 or

(b) if the Convertible Second Lien Notes (as defined below) have not been voluntarily redeemed, repurchased, refinanced or otherwise retired by September 30, 2019, September 30, 2019. The maximum credit amount under the 2017 Senior Credit Facility is currently $250.0 million with an initial borrowing base of $40.0 million. The borrowing base is scheduled to be redetermined in March and September of each calendar year, commencing on or about March 1, 2018, and is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. Additionally, both the Subsidiary and the administrative agent may request one unscheduled redetermination of the borrowing base between scheduled redeterminations. The amount of the borrowing base is determined by the lenders in their sole discretion and consistent with their oil and gas lending criteria at the time of the relevant redetermination. The Company may also request the issuance of letters of credit under the 2017 Senior Credit Facility in an aggregate amount up to $10.0 million, which reduce the amount of available borrowings under the borrowing base in the amount of such issued and outstanding letters of credit.

All amounts outstanding under the 2017 Senior Credit Facility shall bear interest at a rate per annum equal to, at the Company's option, either (i) the alternative base rate plus an applicable margin ranging from 1.75% to 2.75%, depending on the percentage of the borrowing base that is utilized, or (ii) adjusted LIBOR plus an applicable margin from 2.75% to 3.75%, depending on the percentage of the borrowing base that is utilized. Undrawn amounts under the 2017 Senior Credit Facility are subject to a 0.50% commitment fee. To the extent that a payment default exists and is continuing, all amounts outstanding under the 2017 Senior Credit Facility will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto.

The 2017 Senior Credit Facility also contains certain financial covenants, including (i) the maintenance of a ratio of Total Debt (as defined in the 2017 Senior Credit Facility) to EBITDAX not to exceed 4.00 to 1.00 as of the last day of any fiscal quarter, (ii) the maintenance of a current ratio (based on the ratio of current assets to current liabilities) not to be less than 1.00 to 1.00 and (iii) until no Convertible Second Lien Notes remain outstanding, (A) the maintenance of a ratio of Total Proved PV10% attributable to the Company’s and Borrower’s Proved Reserves (as defined in the 2017 Senior Credit Facility) to Total Secured Debt (net of any Unrestricted Cash not to exceed $10.0 million) not to be less than 1.50 to 1.00, (B) limitations on cash general and administrative expenses through 2017 of $10.1 million and (C) minimum liquidity requirements.

The obligations under the 2017 Senior Credit Facility are guaranteed by the Company and secured by a first lien security interest in substantially all of the assets of the Company.

13.50% Convertible Second Lien Senior Secured Notes Due 2019

On the Effective Date, 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 1.9 million shares of the Company’s common stock. Upon closing, the Purchasers were issued 10-year costless warrants exercisable into 2.5 million shares of common stock of the Company, will take a second priority lien on all assets of the Debtors, and will have the right to appoint two members to the Board as long as the Convertible Second Lien Notes are outstanding.

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. The Company may not pay cash interest on the Convertible Second Lien Notes until the 10-Q is filed for the quarter ending March 31, 2018.

Senior Credit Facility

On the Effective Date, 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 the Effective Date, in connection with the consummation of the Plan, the Senior Credit Facility was terminated.

Exit Credit Facility

On the Effective Date, upon emergence from bankruptcy, 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. Amounts outstanding under the Exit Credit Agreement were guaranteed by the Company and secured by a security interest in substantially all of the assets of the Company and the Borrower.

The maturity date of the Exit Credit Agreement was September 30, 2018, unless the Borrower notified the Administrative Agent that it intended 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 beared 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 had an 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 Exit Credit Facility was terminated on October 17, 2017 and the $16.7 million outstanding was fully repaid with proceeds drawn from the 2017 Senior Credit Facility.

Obligations Canceled on the Effective Date

The following represents indebtedness for which, on the Effective Date, the obligations of the Company were canceled:

- 8.0% Second Lien Senior Secured Notes due 2018 in the principal amount of $100 million
- 8.875% Second Lien Senior Secured Notes due 2018 in the principal amount of $75 million
- 8.875% Senior Notes due 2019 in the principal amount of $116.8 million
- 5.0% Convertible Senior Notes due 2029 in the principal amount of $6.7 million
- 5.0% Convertible Senior Notes due 2032 in the principal amount of $94.2 million
- 5.0% Convertible Senior Exchange Notes due 2032 in the principal amount of $6.3 million
- 3.25% Convertible Senior Notes Due 2026 in the principal amount of $0.4 million

Interest Expense on Notes

There was no interest expense recognized on the Second Lien Notes or unsecured senior notes listed above 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, respectively. On the Effective Date, the obligations of the Company with respect to interest expense were canceled.

For additional information on our debt and equity instruments, see Note 5—Debt and Note 8—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, 2017. In addition to the contractual obligations presented in the table below, our Consolidated Balance Sheet at December 31, 2017 reflects accrued interest on our bank debt of $0.2 million payable in the first half of 2017. For additional information see Note 5—Debt and Note 10—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	2018	2019	2020	2021	2022 and After
Debt	5	$75,387	$—	$58,664	$—	$16,723	$ —
Office space leases		5,103	1,510	1,540	1,540	513	—
Operations contracts		871	836	20	15	—	—
Total contractual obligations (1)		$81,361	$2,346	$60,224	$1,555	$17,236	$ —

(1) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $3.4 million as of December 31, 2017. We record a separate liability for the asset retirement obligations. See Note 4—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.

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 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.

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, 2017 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 the Effective Date, 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 allocated 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 the Effective Date will not be comparable with the financial statements prior to that date.

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 the Effective Date, 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 the Effective Date, 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 1—Description of Business and 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.

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 Summary of Significant Accounting Policies—Income

Taxes and Note 7—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.

New Accounting Pronouncements

See Note 1—Description of Business and 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 Summary of Significant Accounting Policies, Note 9—Derivative Activities and Note 5—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 crude oil and natural gas 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. In addition, a non-cash write-down of our oil and natural gas properties may be required if future commodity prices experience a sustained and significant decline. We entered into natural gas derivative instruments during 2017 in order to reduce the price risk associated with production in 2017 of approximately 18,000 MMBtu per day. We did not enter into derivatives instruments for trading purposes. Utilizing actual derivative contractual volumes, a hypothetical increase of 10% in the underlying commodity prices would have increased the derivative gas asset position by $0.3 million and increased the derivative oil liability position by $0.2 million as of December 31, 2017. Likewise, a hypothetical decrease of 10% in the underlying commodity prices would have decreased the gas asset position by $0.3 million and decreased the derivative oil liability by $0.2 million as of December 31, 2017. 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, 2017, we had $16.7 million outstanding variable-rate debt and $39.0 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, 2017 and 2016, 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, 2017.

Management of Goodrich Petroleum Corporation

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
Goodrich Petroleum Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Goodrich Petroleum Corporation and subsidiary (the "Company") as of December 31, 2017 (Successor), the related consolidated statements of operations, stockholders' equity and cash flows for the year then ended (Successor), and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2017, and the consolidated results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

Emphasis of Matter

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.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting 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. Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ Moss Adams LLP

Houston, Texas
March 2, 2018

We have served as the Company's auditor since 2017.

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

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	December 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$25,992	$36,850
Accounts receivable, trade and other, net of allowance	1,371	1,998
Accrued oil and natural gas revenue	4,958	3,142
Fair value of oil and natural gas derivatives	2,034	—
Inventory	2,521	4,125
Prepaid expenses and other	1,614	755
Total current assets	38,490	46,870
PROPERTY AND EQUIPMENT:		
Unevaluated properties	5,984	24,206
Oil and gas properties (full cost method)	120,333	60,936
Furniture, fixtures and equipment	1,039	984
	127,356	86,126
Less: Accumulated depletion, depreciation and amortization	(15,899)	(4,006)
Net property and equipment	111,457	82,120
Fair value of oil and natural gas derivatives	566	—
Deferred tax asset	937	—
Other	691	322
TOTAL ASSETS	$152,141	$129,312
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$17,204	$14,392
Accrued liabilities	18,075	3,882
Fair value of oil and natural gas derivatives	1,002	—
Total current liabilities	36,281	18,274
Long term debt, net	55,725	47,205
Accrued abandonment cost	3,367	2,933
Fair value of oil and natural gas derivatives	517	—
Total liabilities	95,890	68,412
Commitments and contingencies (See Note 10)		
STOCKHOLDERS' EQUITY:		
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 10,770,962 and 9,108,826 shares issued and outstanding as of December 31, 2017 and 2016, respectively	108	91
Additional paid in capital	68,446	65,116
Accumulated deficit	(12,303)	(4,307)

Total stockholders' equity	56,251	60,900
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$152,141	$129,312

See accompanying notes to consolidated financial statements.

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

	Successor	Successor	Predecessor
	Year ended December 31, 2017	Period from October 13, 2016 to December 31, 2016	Period ended October 12, 2016
REVENUES:			
Oil and natural gas revenues	$ 45,320	$ 6,537	$ 21,027
Other	833	45	(341)
	46,153	6,582	20,686
OPERATING EXPENSES:			
Lease operating expense	12,125	2,109	6,504
Production and other taxes	1,183	619	1,946
Transportation and processing	6,222	228	1,265
Depreciation, depletion and amortization	12,125	1,556	8,276
Exploration	—	—	577
Impairment	—	2,486	1,583
General and administrative	16,696	2,200	14,474
Gain on sale of assets	—	(2)	(840)
Other	(43)	—	—
	48,308	9,196	33,785
Operating loss	(2,155)	(2,614)	(13,099)
OTHER INCOME (EXPENSE):			
Interest expense	(9,725)	(1,824)	(11,398)
Interest income and other	1,236	1	117
Gain on derivatives not designated as hedges	1,552	—	30
Restructuring	—	—	(5,128)
	(6,937)	(1,823)	(16,379)
Reorganization items, net	118	130	399,422
Income (loss) before income taxes	(8,974)	(4,307)	369,944
Income tax benefit	978	—	—
Net income (loss)	(7,996)	(4,307)	369,944
Preferred stock, net	—	—	11,237
Net income (loss) applicable to common stock	$ (7,996)	$ (4,307)	$ 358,707
PER COMMON SHARE			
Net income (loss) applicable to common stock—basic	$ (0.80)	$ (0.60)	$ 4.64
Net income (loss) applicable to common stock—diluted	$ (0.80)	$ (0.60)	$ 3.69
Weighted average common shares outstanding—basic	9,975	7,184	77,236
Weighted average common shares outstanding—diluted	9,975	7,184	98,369

See accompanying notes to consolidated financial statements.

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

	Successor Year ended December 31, 2017	Successor October 13, to December 31, 2016	Predecessor January 1, 2016 to October 12, 2016
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (7,996)	$ (4,307)	$ 369,944
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depletion, depreciation and amortization	12,125	1,556	8,276
Deferred income taxes	(937)	—	—
(Gain) on derivatives not designated as hedges	(1,552)	—	(30)
Net cash received in settlement of derivative instruments	471	—	—
Impairment	—	2,486	1,583
Embedded derivative	—	—	(5,538)
Amortization of leasehold costs	—	—	67
Share-based compensation (non-cash)	6,863	240	3,307
Gain on sale of assets	—	—	(840)
Amortization of finance cost and debt discount	8,534	1,518	7,425
Reorganization items	(1)	(6,658)	(410,875)
Gain from material transfers	(367)	—	—
Amortization of transportation obligation	—	—	156
Change in assets and liabilities:			
Accounts receivable, trade and other, net of allowance	627	(1,408)	724
Accrued oil and natural gas revenue	(1,816)	1,065	(786)
Inventory	—	—	(265)
Prepaid expenses and other	(881)	(66)	811
Accounts payable	1,888	1,631	(4,332)
Accrued liabilities	1,348	(384)	13,689
Net cash provided by (used in) operating activities	18,306	(4,327)	(16,684)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(28,763)	(3,232)	(3,789)
Proceeds from sale of assets	563	849	294
Net cash used in investing activities	(28,200)	(2,383)	(3,495)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments of bank borrowings	(16,651)	(23,742)	—
Proceeds from bank borrowings	16,723	—	13,000
Proceeds from equity offering, net of issuance costs	—	23,622	—
Proceeds from Second Lien Notes	—	40,000	—
Note conversions	—	—	(804)
Debt issuance costs	(694)	—	(114)
Issuance cost, net	(342)	—	—
Other	—	—	(5)
Net cash provided by (used in) financing activities	(964)	39,880	12,077
Increase (decrease) in cash and cash equivalents	(10,858)	33,170	(8,102)

Cash and cash equivalents, beginning of period	36,850	3,680	11,782
Cash and cash equivalents, end of period	$ 25,992	$ 36,850	$ 3,680
Supplemental disclosures of cash flow information:			
Cash paid during the year for interest	$ 1,228	$ 498	$ 1,656
Cash paid during the year for taxes	$ —	$ —	$ —
Increase (decrease) in non-cash capital expenditures	$ 9,863	$ 556	$ (836)

See accompanying notes to consolidated financial statements.

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

	Preferred Stock		Common Stock		Additional Paid-in	Treasury Stock		Retained Earnings/	Total Stockholders'
Predecessor Company	Shares	Value	Shares	Value	Capital	Shares	Value	(Deficit)	Equity/(Deficit)
Balance at December 31, 2015	1,502	$1,502	63,910	$12,782	$1,069,673	(173)	$(41)	$(1,492,001)	$ (408,085)
Net income	—	—	—	—	—	—	—	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
Net loss	—	—	—	—	—	—	—	(7,996)	(7,996)
Share-based compensation	—	—	—	—	4,458	—	—	—	4,458
Restricted stock vesting	—	—	232	2	(2)	—	—	—	—
Second Lien warrants and conversion	—	—	1,430	15	(158)	(1)	(7)	—	(150)

Issuance cost	—	—	—	—	(37)	—	—	—	(37)
Treasury stock activity	—	—	—	—	(931)	1	7	—	(924)
Balance at December 31, 2017 Successor	—	$—	10,771	$108	$68,446	—	$—	$(12,303)	$ 56,251

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
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NOTE 1—Description of Business and Summary of Significant Accounting Policies

Goodrich Petroleum Corporation ("Goodrich" and, together with its subsidiary, Goodrich Petroleum Company, L.L.C. (the "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) 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.

Basis of Presentation

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 included cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at date of purchase.

Accounts Payable—Accounts payable consisted of the following items as of December 31, 2017 and 2016 (in thousands):

	December 31,	
	2017	2016
Trade Payables	$4,092	$2,357
Revenue Payables	10,692	10,943
Prepayments from Partners	2,193	966
Other	227	126
Total Accounts Payable	$17,204	$14,392

Accrued Liabilities—Accrued liabilities consisted of the following items as of December 31, 2017 and 2016 (in thousands):

	December 31,	
	2017	2016
Accrued capital expenditures	$10,511	$648
Accrued lease operating expense	786	547
Accrued production and other taxes	449	552
Accrued transportation and gathering	1,130	70
Accrued performance bonus	3,869	—
Accrued interest	244	278

Accrued office lease	696	99
Accrued reorganization costs	168	1,235
Accrued general and administrative expense and other	222	453
	$18,075	$3,882

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Inventory—Inventory consisted of casing and tubulars that are expected to be used in our capital drilling program. 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 US 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 the Effective Date, 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 were capitalized. When proved reserves were found on an unproved property, the associated leasehold cost was transferred to proved properties. Significant unproved leases were reviewed periodically, and a valuation allowance was provided for any estimated decline in value. Costs of all other unproved leases were amortized over the estimated average holding period of the leases. Development costs were capitalized, including the costs of unsuccessful development wells. Additionally, oil and gas properties were assessed for impairment in accordance with Accounting Standards Codification 360.

Because a new entity was 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 better reflects the true economics of exploring for and developing our oil and gas reserves. Therefore, since the Effective Date, 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 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 natural gas properties and thereby subject to DD&A and the full cost ceiling test. For the year ended December 31, 2017 and for the period from the Effective Date to December 31, 2016, we transferred $18.8 million and $2.5 million, respectively, from unevaluated properties to proved oil and natural gas properties. Our sales of oil and natural gas properties are accounted for as adjustments to net proved oil and natural gas properties with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

After the Effective Date and under the Full Cost Method, we amortize our investment in oil and natural gas properties through DD&A expense using the units of production (the “UOP”) method. An amortization rate is calculated based on total proved reserves converted to equivalent thousand cubic feet of natural gas (“Mcfe”) as the denominator and the net book value of evaluated oil and gas asset together with the estimated future development cost of the proved undeveloped reserves as the numerator. The rate calculated per Mcfe is applied against the periods' production also converted to Mcfe to arrive at the periods' DD&A expense.

Prior to the Effective Date and under the Successful Efforts Method, depreciation and depletion of producing oil and natural gas properties was calculated using the units-of-production method. Proved developed reserves were used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves were 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.

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.

The Full Cost Ceiling Test performed as of December 31, 2016 resulted in recording a $2.5 million write-down of the oil and gas properties. The Full Cost Ceiling Test performed as of December 31, 2017 resulted in no write-down of the oil and gas properties.

Exploration—Prior to the Effective Date, 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.

Impairment—Prior to the Effective Date under the Successful Efforts Method of Accounting, we periodically assessed 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 included 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 was 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 was 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 were 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 recognized 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.

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. We have no Level 1 instruments;
- Level 2 Inputs- quotes that are derived principally from or corroborated by observable market data. Included in this Level are our Exit 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

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- 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 our initial measurement of asset retirement obligations.

As of December 31, 2017 and 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.

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. See Note 4.

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, 2017 and 2016, the net liability for natural gas balancing was immaterial. Differences between actual production and net working interest volumes are routinely adjusted.

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. All of our realized gain or losses on our derivative contracts are the result of cash settlements. We have not designated any of our derivative contracts as hedges; accordingly, changes in fair value are reflected in earnings. See Note 9.

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. See Note 7.

Net Income or Net Loss Per Share—Basic income (loss) per common share is computed by dividing net income (loss) applicable to common stockholders for each reporting period by the weighted-average number of common shares outstanding during the period. Diluted income (loss) per common share is computed by dividing net income (loss) applicable 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 restricted stock calculated using the treasury stock method and the potential dilutive effect of the conversion of convertible securities, such as warrants and convertible notes, into shares of our common stock. See Note 6.

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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. See Note 10.

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, 2017, and pro forma full year 2016 are as follows:

	Year Ended December 31,	
	2017	2016 (Pro Forma)
Genesis Crude Oil LP	20 %	44 %
Sunoco, Inc.	13 %	30 %
Williams Energy Resources LLC	29 %	— %
ETC	15 %	4 %
Occidental Energy MA	7 %	13 %

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. See Note 3.

Guarantee—As of the December 31, 2017 Goodrich Petroleum Company LLC, the wholly owned subsidiary of Goodrich Petroleum Corporation was the Subsidiary Guarantor of our 13.50% Convertible Second Lien Senior Secured notes due 2019 (the “Convertible Second Lien Notes”).

Debt Issuance Cost—The Company records debt issuance costs associated with its Convertible Second Lien Notes as a contra balance to long term debt, net in our Consolidated Balance Sheets, which is amortized straight-line over the life of the Convertible Second Lien Notes. Debt issuance costs associated with our revolving credit facility debt are recorded in other assets in our Consolidated Balance Sheets, which is amortized straight-line over the life of such debt.

New Accounting Pronouncements

On August 28, 2017, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities. This ASU is intended to improve the financial reporting of hedging relationships to better portray the economic results of an entity’s risk management activities in its financial statements. In addition, the amendments in this ASU make certain targeted improvements to simplify the application of the hedge accounting guidance in current GAAP based on the feedback received from preparers, auditors, users, and other stakeholders. For public entities, the amendments in this ASU are effective for annual periods beginning after December 15, 2018. We do not expect this ASU to have a material impact on our consolidated financial statements as we currently mark to market all of our derivative positions; however, we are evaluating the impact of this ASU should we choose to utilize hedge accounting in the future.

On May 10, 2017, the FASB issued ASU 2017-09, Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting. This ASU amends the scope of modification accounting for share-based payment arrangements and provides guidance on the types of changes to the terms or conditions of share-based payment awards to which an entity would be required to apply modification accounting under ASC 718. For public entities, the amendments in this ASU are effective for annual periods beginning after December 15, 2017 and should be applied prospectively to an award modified on or after the adoption date. We plan to adopt this ASU on January 1, 2018 and believe the provisions of this ASU will be immaterial to our consolidated financial statements.

On November 17, 2016, the FASB issued ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash. This ASU is intended to reduce diversity in the presentation of restricted cash and restricted cash equivalents in the statement of cash flows and requires that restricted cash and restricted cash equivalents be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendments in this ASU should be applied using a retrospective transition method to each period presented. For public entities, the amendments are effective for annual periods beginning after December 15, 2017. We do not anticipate this standard will have a material impact on our consolidated financial statements.

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. We adopted this standard in 2017 and recognized associated tax windfalls, which were offset by a valuation allowance on our consolidated balance sheet as of December 31, 2017. We note that there were no other material impacts on our consolidated financial statements as a result of adopting this standard.

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. In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842. The update provides an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840. 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 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 December 2016, the FASB issued ASU 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers. The update was issued to increase stakeholders’ awareness of the proposals for technical corrections and to expedite improvements. These ASUs are effective for annual and interim periods beginning after December 15, 2017. The Company plans to adopt these standards using the full retrospective transition method. The Company analyzed the impact of Update 2014-09, and the related ASU's, to evaluate the impact of the new standard on its revenue contracts and does not expect a material impact to our recording of revenue or consolidated financial statements. The Company is currently preparing to comply with new disclosure requirements beginning in Q1 2018 in accordance with requirements of these standards.

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NOTE 2—Fresh Start Accounting

Emergence from 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 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”).
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.

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.

The Company accounted for the bankruptcy in accordance with the Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 852, “Reorganizations”. 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.

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 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.

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.
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.

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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.

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):

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	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