GOODRICH PETROLEUM CORP
Form 10-K
March 05, 2019

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2018

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	**(I.R.S. Employer**

incorporation or organization)	**Identification No.)**
801 Louisiana, Suite 700	
	77002
Houston, Texas	
(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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III 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
Non-accelerated filer	Smaller reporting company

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

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, 2018, the last business day of the Registrant's most recently completed second fiscal quarter) was approximately $61.1 million. The number of shares of the Registrant's common stock par value $0.01 per share, outstanding as of March 1, 2019 was 12,151,318.

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 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.

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GOODRICH PETROLEUM CORPORATION

ANNUAL REPORT ON FORM 10-K

FOR THE FISCAL YEAR ENDED

December 31, 2018

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PART I

Items 1. and 2. ***Business and Properties***
General

Goodrich Petroleum Corporation, a Delaware corporation (together with its subsidiary, Goodrich Petroleum Company, L.L.C. (the "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 173 producing oil and natural gas wells located in 37 fields in seven states. At December 31, 2018, we had estimated proved reserves of approximately 480 Bcfe, comprised of 471 Bcf of natural gas and 1.4 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.

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 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.

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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.

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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, 2018, nearly all of our proved oil and natural gas reserves were located in Louisiana, Texas and Mississippi. We spent substantially all of our 2018 capital expenditures of $106.9 million in the Haynesville Shale Trend of Northwest Louisiana. Our total capital expenditures, including accrued costs for services performed during 2018, consisted of $106.2 million for drilling and completion costs, $0.4 million for asset retirement obligations, and $0.3 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 2019 capital expenditure budget is planned for Haynesville Shale Trend development.

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The table below details our acreage positions, average working interest and producing wells as of December 31, 2018.

Field or Area	**Acreage As of December 31, 2018 Gross**	**Net**	**Average Producing Well Working Interest**		**Producing wells at December 31, 2018**
Tuscaloosa Marine Shale Trend	50,487	35,095	65	%	37
Haynesville Shale Trend	40,970	22,637	35	%	109
Eagle Ford Shale Trend	28,190	12,276	-		-
Other	33,125	7,324	13	%	27

Haynesville Shale Trend

As of December 31, 2018, we have acquired or farmed-in leases totaling approximately 41,000 gross (22,600 net) acres in the Haynesville Shale Trend. During 2018, we added 16 gross (7.5 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, 2018, we had 3 gross (2.9 net) wells in the drilling or completion phase in the Haynesville Shale Trend.

On February 28, 2018, we closed on the sale of working interests in certain oil and gas leases, wells, units and facilities and certain net leasehold interests in a portion of our undeveloped acreage in the Angelina River Trend in Angelina and Nacogdoches Counties, Texas for total consideration of approximately $23.0 million, with an effective date of January 1, 2018. The disposition was subject to customary post-closing adjustments.

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Tuscaloosa Marine Shale Trend

As of December 31, 2018, we have acquired approximately 50,500 gross (35,100 net) lease acres in the TMS, an oil shale play in Southwest Mississippi and Southeast Louisiana. Approximately 47,600 gross (32,900 net) acres are currently held by production. During 2018, we did not conduct any drilling operations and did not add any wells to production. As of December 31, 2018, we had 2 gross (1.7 net) wells waiting on completion operations in the TMS.

On May 21, 2018, the Company closed on the sale of working interests in certain oil and gas leases, wells, facilities and leasehold acres in our TMS operating area located in East and West Feliciana Parish, Louisiana for total consideration of approximately $3.3 million with an effective date of May 1, 2018. The disposition was subject to customary post-closing adjustments.

Eagle Ford Shale Trend

As of December 31, 2018, we have acquired or farmed-in leases totaling approximately 28,200 gross (12,300 net) lease acres in the Eagle Ford Shale Trend, which is held for future development or sale.

Other

As of December 31, 2018, 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, 2018 and 2017, 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, 2018 on properties other than those located in the TMS. RSC prepared the estimate of proved reserves as of December 31, 2018 for our TMS properties. Copies of the summary reserve reports of NSAI and RSC as of December 31, 2018 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 PV-10 estimates at December 31, 2018 below, were calculated using flat, twelve month average commodity index prices of $65.56 per barrel and $3.10 per Mmbtu.

	Proved Reserves at December 31, 2018			
	Developed Producing	**Developed Non-Producing**	**Undeveloped**	**Total**
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	1,441	-	-	1,441
Natural Gas (Mmcf)	91,404	714	378,819	470,937
Mcf Natural Gas Equivalent (Mmcfe) (2)	100,050	714	378,819	479,583
Estimated Future Net Cash Flows				$734,048
PV-10 (3)				$417,770
Discounted Future Income Taxes				(20,185)
Standardized Measure of Discounted Net Cash Flows (3)				$397,585

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	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

(1) Includes condensate.

(2) Based on ratio of six Mcf of natural gas per Bbl of oil and per Bbl of NGLs. NGLs are immaterial and included in Natural Gas.

(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:

	As of December 31, 2018			
Area	**Proved Developed**	**Proved Undeveloped**	**Proved Reserves**	**% of Total**
Tuscaloosa Marine Shale Trend	8,582	-	8,582	2 %
Haynesville Shale Trend	92,049	378,819	470,868	98 %
Other	133	-	133	0 %
Total	100,764	378,819	479,583	100 %

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

In accordance with the guidelines of the SEC, our independent reserve engineers' estimates of future net revenues from our estimated proved reserves, and the PV-10 and standardized measure thereof, were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price for the period of January 2018 through December 2018, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For reserves at December 31, 2018, the average twelve month prices used were $3.10 per MMBtu of natural gas and $65.56 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, 2018 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 internal 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, 2018, as estimated by NSAI and RSC, were 480 Bcfe, consisting of 471 Bcf of natural gas and 1.4 MMBbls of oil and condensate. In 2018, we added approximately 100 Bcfe related to our drilling activities in the Haynesville Shale Trend. We had negative revisions of approximately 19 Bcfe, divestures of approximately 4 Bcfe and produced 26 Bcfe in 2018. We are employing newer completion techniques on our Haynesville Shale Trend wells which have been proven on the successful producing wells we drilled in 2018 and 2017. These well results in conjunction with our acreage position and our financial ability to develop our Haynesville Shale Trend properties allowed us to add the Haynesville Shale Trend reserves as of December 31, 2018.

Our proved undeveloped ("PUD") reserves at December 31, 2018, all in our Haynesville Shale Trend, were 379 Bcfe, or 79% of our total proved reserves. In 2018, we had new additions of 34 Bcfe. We had net positive revision of previous estimates of 2 Bcfe and decreases as a result of acreage swaps of 9 Bcfe. We developed approximately 11 Bcfe, or 3% of our total proved undeveloped reserves booked as of December 31, 2017, through the drilling of 2 gross (0.8 net) development wells. Of the proved undeveloped reserves in our December 31, 2018 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 was attributable to ownership increases of 46 Bcfe, increase of 34 Bcfe due to commodity price improvements offset by a decrease of 78 Bcfe due to economic parameter adjustment such as increased operating expenses.

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Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2018:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Tuscaloosa Marine Shale Trend:						
Southeast Louisiana	14	9.9	-	-	14	9.9
Southwest Mississippi	23	14.3	-	-	23	14.3
Haynesville Shale Trend:						
East Texas	-	-	2	0.8	2	0.8
Northwest Louisiana	-	-	107	37.6	107	37.6
Other	6	0.2	21	3.3	27	3.5
Total Productive Wells	43	24.4	130	41.7	173	66.1

(1) Royalty and overriding interest wells that have immaterial values are excluded from the above table.
(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, 2018. Acreage in which our interest is limited to a farm-out agreement, 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	28,288	19,737	1,775	1,113	30,063	20,850
Southeast Louisiana	19,313	13,161	1,111	1,084	20,424	14,245
Haynesville Shale Trend:						
East Texas	33,367	9,074	4,628	678	37,995	9,752

Northwest Louisiana	25,616	18,920	8,373	1,085	33,989	20,005
Eagle Ford Shale Trend:						
South Texas	10,430	7,457	17,760	4,819	28,190	12,276
Other	2,102	195	9	9	2,111	204
Total	119,116	68,544	33,656	8,788	152,772	77,332

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.

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Lease Expirations

We have undeveloped lease 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, 2018:

Year	Net Acreage
2019	2,513
2020	8,339
2021	57
2022	-

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,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	16	7.5	5	1.5	2	0.4
Non-Productive	-	-	-	-	-	-
Total	16	7.5	5	1.5	2	0.4
Exploratory Wells:						
Productive	-	-	-	-	-	-
Non-Productive	-	-	-	-	-	-

Total	-	-	-	-	-	-
Total Wells:						
Productive	16	7.5	5	1.5	2	0.4
Non-Productive	-	-	-	-	-	-
Total	16	7.5	5	1.5	2	0.4

At December 31, 2018, we had 5 gross (4.6 net) development wells waiting to be completed.

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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, 2018), 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, 2018.

	Sales Volumes			Average Sales Prices (1)				Average
	Natural Gas Mmcf	Oil & Condensate MBbls	Total Mmcfe	Natural Gas Mmcf	Oil & Condensate MBbls	Total Mmcfe	% of Total Revenue	Production Cost (2) Per Mcfe
For Year 2018:								
TMS	-	215	1,289	$ -	$ 68.03	$ 11.34	17 %	$ 4.37
Haynesville Shale Trend	24,410	-	24,410	2.99	-	2.99	83 %	0.19
Other	34	2	47	4.18	58.11	5.72	0 %	2.38
Total	24,444	217	25,746	$ 2.99	$ 67.93	$ 3.42	100 %	$ 0.41
For Year 2017:								
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	0 %	3.84
Total	10,323	304	12,150	$ 2.90	$ 50.90	$ 3.73	100 %	$ 1.00
For Year 2016 (Pro Forma) (3):								
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	0 %	3.69
Total	5,555	476	8,410	$ 1.47	$ 40.80	$ 3.28	100 %	$ 1.02

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.
(3) 2016 Pro Forma results is the combined Successor and Predecessor periods of 2016 after our emergence from bankruptcy on October 12, 2016.

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, 2018 and 2017 are as follows:

	Year Ended December 31,	
	2018	**2017**
CIMA Energy, LP	41%	0 %
ETC	15%	15%
Genesis Crude Oil LP	13%	20%
Sunoco, Inc.	4 %	13%
Williams Energy Resources LLC	1 %	29%
Occidental Energy MA	1 %	7 %

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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 28, 2019 we had 47 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.

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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 the 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 the RCRA. The consent decree requires the 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”, or “CWA”), 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 “WOTUS” rule). Several legal challenges to the rule followed, along with attempts to stay implementation following the change in presidential administration. Currently, the WOTUS rule is active in 22 states and enjoined in 28 states. However, in December 2018, the EPA and the Corps proposed changes to regulations under the CWA that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced their intentions to challenge the proposed WOTUS replacement rule. Therefore, the scope of jurisdiction under the CWA is uncertain at this time. To the extent any 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.

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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 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 certain limited circumstances. 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 where we operate, including Louisiana and Texas, 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.

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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, and the agency completed attainment/non-attainment designations in July 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, known as Subpart OOOOa, 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. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result of the above, substantial uncertainty exists with respect to implementation of the EPA methane rule. 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 to reduce 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. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Moreover, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or to shift away from more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult to engage in exploration and production activities. Finally, it should be noted that many 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.

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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.

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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 variations on 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.*

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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 commitments.

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, 2018, 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.

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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 be successful or may not result in the levels of production or reserves we have estimated. Exploration activities involve numerous risks, 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 and increased costs could reduce the profitability of our operations. 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. In recent years, we have paid for these expenditures with cash from operating activities and, to a lesser extent, borrowings under our 2017 Senior Credit Facility (as described below). 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 to the extent required or on acceptable terms if our cash flows from operations are not sufficient to fund our capital expenditure requirements. 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, 2018, 79% 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. In addition, 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 statements 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 2018. 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.

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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.

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

We had operating income of $17.4 million for the year ended December 31, 2018 but had an operating loss of $2.2 million for the year ended December 31, 2017. We had an accumulated deficit of $10.6 million at December 31, 2018. 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 sustain profitability or positive cash flows provided by operating activities in the future.

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 positive net cash settlements of $0.5 million during 2017 and negative net cash settlements of $3.2 million during 2018.

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.*

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 “Act”) 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 Act. 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 Act may have on us, and it could adversely affect our business, financial condition and results of operations.

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 non-cash impairment writedowns, which would result in a negative impact to our earnings and financial position. We account for our Oil and Natural Gas Properties under the Full Cost Method of accounting. 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 years ended December 31, 2017 and 2018.

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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, 2018 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, 2018, approximately 22% of our reserves and approximately 18% 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.

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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, 2018 and 2017 were 41% and 29%, 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, 2018 and 2017 are as follows:

	Year Ended December 31,	
	2018	**2017**
CIMA Energy, LP	41%	0 %
ETC	15%	15%
Genesis Crude Oil LP	13%	20%
Sunoco, Inc.	4 %	13%
Williams Energy Resources LLC	1 %	29%
Occidental Energy MA	1 %	7 %

Competition in the oil and natural gas industry is intense, and we are smaller and have more limited operating resources 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.

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

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

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

- well blowouts;
- cratering;
- explosions;
- uncontrollable flows of oil, natural gas, brine or well fluids;
- fires;
- formations with abnormal pressures;
- shortages of, or delays in, obtaining water for hydraulic fracturing operations;
- environmental hazards such as crude oil spills;
- natural gas leaks;

- pipeline and tank ruptures;
- unauthorized discharges of brine, well stimulation and completion fluids or toxic gases into the environment;
- encountering naturally occurring radioactive materials;
- other pollution; and
- other hazards and risks.

Any of these operating hazards could result in substantial losses to us. As a result, substantial liabilities to third parties or governmental entities may be incurred. The payment of these amounts could reduce or eliminate the funds available for exploration, development or acquisitions. These reductions in funds could result in a loss of our properties. Additionally, some of our oil and natural gas operations are located in areas that are subject to weather disturbances such as hurricanes. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;

- well blowouts in some cases; and
- workers compensation.

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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 and Convertible Second Lien Notes, which could result in an event of default that, if not cured or waived, would have a material adverse effect on our business, financial condition and results of operations.

Our Convertible Second Lien Notes (as defined below) and our 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 (as amended, the "2017 Senior Credit Facility"), the Company and the Subsidiary contain various affirmative and negative covenants with which we must comply. For example, under the 2017 Senior Credit Facility, we 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 plus availability under the current borrowing base 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 PV-10 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 and (B) 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, 2019, we have outstanding (i) costless warrants granted to the Convertible Second Lien Notes Purchasers representing 150,000 shares of our common stock, (ii) 1.0 million warrants exercisable into approximately 1.4 million shares of the Company's common stock at an exercise price of $16.22 per share and (iii) approximately 1.0 million restricted stock awards, representing in total approximately 17% of our shares on a fully diluted basis. 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.

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.

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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 tribal 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 certain limited circumstances. 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, such legislation has not been passed. At the state level, some states where we operate, including Louisiana and Texas, 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.

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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 preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the annual reporting of greenhouse gas emissions from certain petroleum and natural gas system sources in the United States, including among others, onshore and offshore production facilities, including certain of our operations. 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 Source Performance Standards ("NSPS"), known as Subpart OOOOa, 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, following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. 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 September 2018, the BLM issued a final rule rescinding the agency's 2016 methane rule, and litigation challenging the rescission is pending. As a result of the above, substantial uncertainty exists with respect to implementation of the EPA and BLM methane rules. 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 to reduce 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. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Moreover, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or to shift away from more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult to engage in exploration and production activities. Finally, it should be noted that many 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.

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

Our common stock is listed on the NYSE American. The market price of our common stock could be subject to wide fluctuations in response to, and the level of trading that develops with our common stock may be affected by numerous factors, many of which are beyond our control. These factors include, among other things, our limited trading volume, the concentration of holdings of our common stock, 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.

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The ability to attract and retain key personnel is critical to the success of our business.

The success of our business depends on key personnel. The ability to attract and retain these key personnel may be difficult in light of 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.

Currently, the majority of our common stock is held by four investment funds. 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"), we have a staggered Board of Directors ("Board") and five of our seven directors are nominated by constituencies of our security holders, 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 there is less liquidity in our stock and 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.

Our business could be adversely affected by security threats, including cybersecurity threats.

As a producer of crude oil and natural gas, we face various security threats, including cybersecurity threats to gain unauthorized access to our sensitive information or to render our information or systems unusable, and threats to the security of our facilities and infrastructure or third-party facilities and infrastructure. The potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business, financial condition and results of operations. For example, unauthorized access to our reserves information or other proprietary information could lead to data corruption, communication interruptions, or other disruptions to our operations.

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

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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.

Item 4. ***Mine Safety Disclosures***

Not Applicable.

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PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities. Not Applicable for Smaller Reporting company***

Market Price of Our Common Stock

Upon our bankruptcy emergence on October 12, 2016, 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, 2019, the number of holders of record of our common stock was 88 and 12,151,318 shares were outstanding. High and low sales prices for our common stock for each quarter during 2018 and 2017 were as follows:

	2018		**2017**	
	High	**Low**	**High**	**Low**
First Quarter	$12.60	$10.35	$15.00	$13.00
Second Quarter	14.64	10.68	17.25	10.81
Third Quarter	14.43	11.98	14.37	8.20
Fourth Quarter	15.37	12.79	11.95	8.96

The over-the-counter market quotations for January 1, 2017 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, 2018.

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 divestitures, 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.

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, 2018, we held approximately 22,600 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, 2018, we had $4.1 million in cash and a borrowing base of $75 million, subject to an elected draw limit of $50 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 (as amended, the "2017 Senior Credit Facility") on which we had $23 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.

Overview of 2018 Results

- We conducted drilling or completion operations on 19 wells, adding 16 gross (7.5 net) wells to production in the Haynesville Shale Trend;
- We ended the year with 480 Bcfe of proved oil and natural gas reserves with a PV-10 of $418 million;
- We achieved an average daily equivalent production rate of 70,537 Mcfe per day representing a 112% increase from 2017;
- We increased our oil and natural gas revenues to $87.9 million, representing an increase of 94% from 2017;
- We generated net income of $1.8 million or $0.15 per share (basic) and $0.13 per share (diluted).

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 41,000 gross (22,600 net) acres as of December 31, 2018 producing from or prospective for the Haynesville Shale Trend. We incurred drilling or completion costs on 19 wells in 2018, spending $103.3 million of which $0.1 million was leasehold cost. We added 16 gross (7.5 net) wells to production in 2018. Our net production volumes from our Haynesville Shale Trend wells represented approximately 95% of our total equivalent production on a Mcfe basis and substantially all of our total natural gas production for the year ended December 31, 2018.

Tuscaloosa Marine Shale Trend

We held approximately 50,500 gross (35,100 net) acres in the TMS as of December 31, 2018 with approximately 47,600 gross (32,900 net) acres held by production. During 2018, we sold 3 gross (2.0 net) wells and did not conduct any drilling operations in the TMS; however, we had 2 gross (1.7 net) wells drilled in 2015, which are still waiting on completion. Our net production volumes from our TMS wells represented approximately 5% of our total equivalent production on a Mcfe basis and approximately 99% of our total oil production for the year ended December 31, 2018. During 2018, we did not spend any capital in the TMS; however, we did spend $0.9

million on workover expense activities to maintain volumes on producing wells.

Eagle Ford Shale Trend

As of December 31, 2018, we have retained approximately 12,300 net acres of undeveloped leasehold in Frio County, Texas, which is prospective for future development or sale.

Results of Operations

For the year ended December 31, 2018, we reported net income of $1.8 million, or $0.15 per share (basic) and $0.13 per share (diluted), on oil and gas revenues of $87.9 million. This compares to a net loss of $8.0 million, or $0.80 per share (basic and diluted) for the year ended December 31, 2017. The recurring items that had the most material financial effect on our net income for the year ended December 31, 2018 were increased oil and gas revenues offset by increased transportation and processing cost, increased depreciation, depletion and amortization cost and losses on derivatives not designated as hedges. All of these items can be primarily attributed to our increased production volumes, and to a lesser extent the increase in prices.

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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:	**Year Ended December 31, 2018**	**Year Ended December 31, 2017**	**Variance**	
Revenues:				
Natural gas	$ 73,198	$ 29,829	$43,369	145 %
Oil and condensate	$ 14,745	$ 15,491	$(746)	(5 %)
Natural gas, oil and condensate	$ 87,943	$ 45,320	$42,623	94 %
Net Production:				
Natural gas (Mmcf)	24,444	10,323	14,121	137 %
Oil and condensate (MBbls)	217	304	(87)	(29 %)
Total (Mmcfe)	25,746	12,150	13,596	112 %
Average daily production (Mcfe/d)	70,537	33,288	37,249	112 %
Average Realized Sales Price Per Unit:				
Natural gas (per Mcf)	$ 2.99	$ 2.89	$0.10	3 %
Natural gas (per Mcf) including the effect of realized gains/losses on derivatives	$ 2.94	$ 2.94	$-	0 %
Oil and condensate (per Bbl)	$ 67.93	$ 50.90	$17.03	33 %
Oil and condensate (per Bbl) including the effect of realized gains/losses on derivatives	$ 59.27	$ 50.61	$8.66	17 %
Average realized price (per Mcfe)	$ 3.42	$ 3.73	$(0.31)	(8 %)

Oil and Natural Gas Revenue

Natural gas, oil and condensate revenues increased in 2018 compared to 2017 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 realized sales prices and in natural gas production contributed approximately $6.2 million and $42.3 million, respectively, to the increase in revenue. Decreased oil and condensate production reduced revenue by approximately $5.9 million compared to 2017. The increase in natural gas production volumes is attributed to 16 Haynesville Shale Trend wells put on production during 2018. We continue to concentrate our operational activities and resources on increasing natural gas production in the Haynesville Shale Trend.

The difference between our average realized prices inclusive of net cash derivative settlements for the years ended December 31, 2018 and 2017 relates to our oil and natural gas contracts. In 2018, we paid a net $1.4 million on natural gas derivative settlements on a daily average of approximately 30,600 Mmbtu with a weighted average fixed price of $3.01 per Mmbtu and paid a net $1.9 million on oil derivative settlements on a daily average of 375 barrels at a weighted average price of $51.08 per barrel. 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 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)	**Year Ended December 31, 2018**	**Year Ended December 31, 2017**	**Variance**	
Lease operating expenses	$ 10,446	$ 12,125	$(1,679)	(14 %)
Production and other taxes	2,605	1,183	1,422	120%
Transportation and processing	11,046	6,222	4,824	78 %

Per Mcfe	**Year Ended December 31, 2018**	**Year Ended December 31, 2017**	**Variance**	
Lease operating expenses	$ 0.41	$ 1.00	$(0.59)	(59%)
Production and other taxes	$ 0.10	$ 0.10	$-	0 %
Transportation and processing	$ 0.43	$ 0.51	$(0.08)	(16%)

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Lease Operating Expense

Lease operating expense decreased $1.7 million during the year ended December 31, 2018 compared to the prior year period in 2017. The decrease is substantially attributed to decreased workover expense and lower per unit costs for new Haynesville Shale Trend wells compared to the same period in 2017, offset by increased costs due to an increased well count in 2018. We incurred $3.4 million in workover expense for the year in 2017 and only $1.4 million for the year in 2018. The majority of the workover expense incurred in 2018 is attributed to our TMS wells in the effort to maintain our oil production. Lease operating expense exclusive of workover expense on a per unit basis was $0.35 and $0.72 per Mcfe for the years 2018 and 2017, respectively. We expect per unit lease operating expense to continue to decrease as we increase production from the Haynesville Shale Trend, which carries a lower per unit lease operating expense than our current per unit rate.

Production and Other Taxes

Production and other taxes for the year ended 2018 included severance tax of $1.8 million and ad valorem tax of $0.8 million. Severance taxes increased $0.5 million in 2018 compared to 2017 driven by expiration of our oil severance tax exemptions in Mississippi and Louisiana and to a lesser extent an increase in revenues. 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, 2023, 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 and from the $0.098 per Mcf (through June 30, 2017), $0.111 per Mcf (from July 1, 2017 through June 30, 2018) and $0.122 per Mcf (starting on July 1, 2018) severance tax on natural gas 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. Our recently drilled Haynesville Shale Trend natural gas wells in Northwest Louisiana are currently benefiting from this exemption.

Ad valorem tax increased $0.9 million in 2018 compared to 2017. Ad valorem tax in 2017 included audit refunds of approximately $0.9 million while no refunds were received in 2018.

Transportation and Processing

Our natural gas production incurs substantially all of our transportation and processing cost. Transportation and processing expenses for the year ended December 31, 2018 increased while per unit expense decreased compared to the year ended December 31, 2017, reflecting increased production from our operated Haynesville Shale Trend wells. Our natural gas volumes from operated wells generally carry less transportation cost than those from wells we do not operate. Our per unit transportation cost will continue to decrease as we increase our operated natural gas production under more favorable transportation contracts.

(in thousands)	Year Ended December 31, 2018	Year Ended December 31, 2017	Variance	
Depreciation, depletion & amortization	$ 26,809	$ 12,125	$ 14,684	121 %
General & administrative	19,663	16,696	2,967	18 %
Other	7	(43)	50	116 %

Per Mcfe	Year Ended December 31, 2018	Year Ended December 31, 2017	Variance	
Depreciation, depletion & amortization	$ 1.04	$ 1.00	$ 0.04	4 %
General & administrative	$ 0.76	$ 1.37	$ (0.61)	(45 %)
Other	$ -	$ -	$ -	0 %

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

DD&A expense in 2018 and 2017 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 (for the fourth and first quarters) and mid-year (for the second and third quarters) reserve reports. DD&A increased in 2018 versus prior year as a result of an increase in the DD&A rate based on the year-end 2018 reserve report and also because of additional production volumes to which the DD&A rate was applied. Included in DD&A for 2018 is the depletion of our oil and gas properties of $26.2 million, accretion of our Asset Retirement Obligation of $0.3 million and $0.3 million in depreciation of our furniture and fixtures.

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Impairment

Our Full Cost Ceiling Test performed quarterly did not require recording an impairment in 2018 or 2017.

General and Administrative Expense ("G&A")

General and Administrative Expense for the year ended December 31, 2018 was $19.7 million which includes $6.4 million of share based compensation. The $3.0 million increase in G&A expense in 2018 compared to 2017 is attributed to a $2.0 million increase in share based compensation and $1.0 million increase in employee related expenses, including employee benefits costs and accrued performance bonuses. We capitalized $3.5 million of G&A directly attributed to our capital development to the full cost pool during 2018. Our G&A expense per unit of production decreased in 2018 and is expected to continue to decrease entirely due to our increasing production volumes. It is anticipated that share based compensation expense will also decrease as no substantial stock awards were granted during 2018.

Our 2017 Senior Credit Facility and 13.50% Convertible Second Lien Senior Secured Notes due 2019 (the "Convertible Second Lien Notes", for which the due date has been extended to March 30, 2020) placed limitations on cash general and administrative expenses through December 31, 2017 to $10.1 million. G&A payable in cash, which excluded 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.

Other Income (Expense)

	Year Ended December 31, 2018	**Year Ended December 31, 2017**	**Variance**	
Other Income (Expense):				
Interest expense	$(11,944)	$(9,725)	$2,219	23 %
Interest income and other	508	1,236	(728)	(59 %)
Gain (loss) on derivatives not designated as hedges	(3,986)	1,552	(5,538)	(357%)
Reorganization items gain (loss), net	(305)	118	(423)	(358%)
Income tax benefit	57	978	(921)	(94 %)

Average funded borrowings adjusted for debt discount	$ 55,672	$ 50,708
Average funded borrowings	$ 62,476	$ 60,314

Interest Expense

Interest expense in 2018 included $1.1 million incurred on the 2017 Senior Credit Facility and $10.8 million incurred on the Convertible Second Lien Notes. The interest on the Convertible Second Lien Notes was all non-cash consisting of $6.7 million in paid-in-kind interest and amortized debt discount of $4.1 million.

Interest expense in 2017 included $1.2 million incurred on the 2017 Senior Credit Facility and Exit Credit Facility and $8.5 million incurred on 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 Income and Other

Interest income and other for the year ended December 31, 2018 of $0.5 million primarily related to sales tax refunds received on audits we performed on a contingency basis.

Interest income and other for the year ended December 31, 2017 of $1.2 million primarily related to the receipt of cash that was released from escrow upon a negotiated settlement on longstanding title issues.

Gain/Loss 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. We do not designate our derivative contracts as hedges for accounting purposes. Consequently, the changes in our mark to market valuations are recorded directly to income or loss on our financial statements.

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Loss on commodity derivatives not designated as hedges in 2018 was comprised of a mark to market loss of $0.8 million and a loss of $3.2 million from net cash settlements. The mark to market loss represented a $2.7 million loss in the fair value of our natural gas derivative contracts offset by a $1.9 million gain in the fair value of our oil derivative contracts. The loss on cash settlements reflected a net $1.3 million paid to our counter-parties on settlement of our natural gas derivatives and a net $1.9 million paid to our counter-parties on settlement of oil derivatives.

Gain on commodity derivatives not designated as hedges in 2017 was comprised of a mark to market gain of $1.1 million and gain from net cash settlements of $0.5 million. The mark to market gain represented 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 reflected $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.

Reorganization items, net

We settled the final outstanding bankruptcy claims in 2018, which resulted in a net reorganization loss of $0.3 million for the year ended December 31, 2018 including legal and trustee fees. We settled all remaining claims and closed our bankruptcy case in the third quarter of 2018. In the fourth quarter of 2018, we distributed the remaining approximately 39 thousand shares of common stock and related warrants that were granted to the creditors per the Plan of Reorganization.

Income Tax Benefit

We recorded a $0.1 million income tax benefit for the year ended December 31, 2018 and a $1.0 million income tax benefit for the year ended December 31, 2017. We maintained a valuation allowance at December 31, 2018, which resulted in no net deferred tax asset or liability appearing on our statement of financial position with the exception of a deferred tax asset related to alternative minimum tax (“AMT”) credits. We recorded this valuation allowance after an evaluation of all available evidence (including our recent history of net operating losses in 2017 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 benefits recorded in 2018 and 2017 were due to the projected refund of AMT credits for which we also recorded a non-current deferred tax asset and a current receivable for the amount we expect to receive in 2019.

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 completed the accounting for the effects of the Act during 2017. Our financial statements for the year ended December 31, 2017 reflected certain effects of the Act which included a reduction in the corporate tax rate from 35% to 21% effective

January 1, 2018, as well as other changes.

Adjusted EBITDA

Adjusted EBITDA 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. We define Adjusted EBITDA as earnings before interest expense, income and similar taxes, DD&A, share-based compensation expense and impairment of oil and natural gas properties (if any). In calculating Adjusted EBITDA, 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 is not a measure of net income (loss) as determined by US GAAP. Adjusted EBITDA should not be considered an alternative to net income (loss), as defined by US GAAP.

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The following table presents a reconciliation of the non-US GAAP measure of Adjusted EBITDA to the US GAAP measure of net income (loss), its most directly comparable measure presented in accordance with US GAAP:

(In thousands)	Year Ended December 31, 2018	Year Ended December 31, 2017
Net income (loss) (US GAAP)	$ 1,750	$ (7,996)
Depreciation, depletion and amortization	26,809	12,125
Income tax benefit	(57)	(978)
Share based compensation expense (non-cash)	6,545	6,863
Interest expense	11,944	9,725
Loss (gain) on reorganization	305	(118)
Loss (gain) on commodity derivatives not designated as hedges	3,986	(1,552)
Net cash received (paid) in settlement of derivative instruments	(3,236)	471
Other items (1)	(96)	(38)
Adjusted EBITDA	$ 47,950	$ 18,502

(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 may not be comparable to other similarly totaled measures of other companies.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our primary sources of cash during 2018 were cash on hand at the beginning of the year of $26.0 million, cash flow from operating activities of $49 .2 million, cash proceeds of $26. 8 million from asset sales and $10.3 million net cash draws under our 2017 Senior Credit Facility. We used $105.1 million in cash to fund our drilling and development capital program and used $3.1 million for purchases of treasury stock for tax withholding purposes related to stock compensation.

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, 2018 was $75 million, subject to an elected draw limit of $50 million. The 2017 Senior Credit Facility matures on a) October 17, 2021 or b) December 30, 2019, if the Convertible Second Lien Notes have not been voluntarily redeemed, repurchased, refinanced or otherwise retired by December 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. We may, however, elect to reduce the proposed borrowing base to a lower draw limit by providing notice to the lenders contemporaneously with each redetermination of the borrowing base. 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. 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.

We exited 2018 with $4.1 million of cash on hand and $27.0 million of outstanding borrowings with $23.0 million of availability under the current borrowing base of $50.0 million on the 2017 Senior Credit Facility. We are beginning 2019 with $27.1 million in immediately available capital resources.

Due to the timing of payment of our capital expenditures and timing of borrowings under our 2017 Senior Credit Facility, we reflected a working capital deficit of $21.0 million as of December 31, 2018. To the extent we operate with a working capital deficit, we expect such deficit to be offset by the liquidity available under the 2017 Senior Credit Facility.

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Outlook

Our total capital expenditures for 2019 are expected to be approximately $90 to $100 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 11 gross (9.8 net) wells utilizing improved completion techniques.

We believe the results of the capital investments we made in 2018 will generate additional cash flows and additional value that will allow us to raise capital to continue our capital development into 2019 and beyond.

In addition, to support future cash flows, we entered into strategic derivative positions as of December 31, 2018 covering approximately 53% of our anticipated oil and natural gas sales volumes for 2019. 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:

- availability under the 2017 Senior Credit Facility;
- issuance of equity securities;
- issuance of debt securities;
- joint ventures in our TMS and/or Haynesville Shale Trend acreage; and
- sale of non-core assets.

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

Cash flow statement information:	**Year Ended**	**Year Ended**

	December 31, 2018	December 31, 2017
Net Cash:		
Provided by operating activities	$49,186	$18,306
Used in investing activities	(78,249)	(28,200)
Provided by (used in) financing activities	7,139	(964)
Decrease in cash and cash equivalents	$(21,924)	$(10,858)

At December 31, 2018, our heavily weighted capital expenditures in the second half of 2018 resulted in a working capital deficit of $21.0 million, which was more than offset by the liquidity available under the 2017 Senior Credit Facility. We had approximately $76.8 million in long-term debt as of December 31, 2018.

Cash Flows

For the Year Ended December 31, 2018

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 and net cash settlements related to our derivative contracts also impacted cash flows. Net cash provided by operating activities for the year ended December 31, 2018 was $49.2 million including operating cash flows before working capital changes of $46.3 million reduced by net cash payments of $3.2 million for settlements of derivative contracts. The substantial increase in cash provided by operating activities in 2018 compared to 2017 was attributable to a 94% increase in oil and natural gas revenues driven by a 112% increase in equivalent production volumes.

Investing activities: Net cash used in investing activities was $78.3 million for the year ended December 31, 2018, which reflected cash expended on capital projects of $105.1 million reduced by $26.8 million cash proceeds received from sales of oil and gas properties. We recorded $106.9 million in capital expenditures in this period, which reflected the utilization of $1.2 million of cash calls paid in the previous period, the utilization of $1.9 million from materials inventory, capitalization of $0.4 million in asset retirement obligation and capitalization of $0.7 million of non-cash internal cost reduced by a net $2.4 million in the change of the capital expenditure accrual. We conducted drilling and completion operations on 19 gross (12.1 net) wells bringing 16 gross (7.5 net) wells on production in the Haynesville Shale Trend during the year ended December 31, 2018, and we capitalized $3.5 million in internal costs. We had 5 gross (4.6 net) wells waiting completion at December 31, 2018.

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Financing activities: Net cash provided by financing activities for the year ended December 31, 2018 was $7.1 million consisting of net draws of $10.3 million on the 2017 Senior credit facility reduced by $3.1 million for the purchase of shares withheld from employee stock awards for the payments of taxes and $0.1 million of debt issuance cost paid upon the amendment of the 2017 Senior Credit Facility.

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 represented 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 recorded $41.8 million in capital expenditures, of which we paid out cash amounts totaling $28.8 million for drilling and development operations in the year. The difference was attributed to the utilization of $0.4 million of cash calls paid in the previous period, the utilization of $1.8 million from materials inventory, $0.2 million in asset retirement obligation capitalized and a net $10.6 million increase in the capital expenditure accrual. The period also reflected 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, and we capitalized $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, and $0.7 million in 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 the new credit facility.

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

	December 31, 2018			**December 31, 2017**		
	Principal	**Carrying Amount**	**Fair Value**	**Principal**	**Carrying Amount**	**Fair Value**
2017 Senior Credit Facility (1)	$27,000	$27,000	$27,000	$16,723	$16,723	$16,723
Convertible Second Lien Notes (2)	53,691	49,820	60,857	47,015	39,002	62,026
Total debt	$80,691	$76,820	$87,857	$63,738	$55,725	$78,749

(1) The carrying amounts for the 2017 Senior Credit Facility represent fair value as it was 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 paid-in-kind ("PIK") interest of $13.7 million as of December 31, 2018 and $7.0 million as of December 31, 2017. The carrying value includes $3.9 million and $8.0 million of unamortized debt discount at December 31, 2018 and 2017, respectively. The fair value of the notes was obtained by using the last known sale price for the value on December 31, 2018 and 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:

	Year Ended December 31, 2018			**Year Ended December 31, 2017**		
	Interest Expense	**Effective Interest Rate**		**Interest Expense**	**Effective Interest Rate**	
Exit Credit Facility	$-	0	%	$947	7.1	%
2017 Senior Credit Facility	1,130	8.9	%	244	7.2	%
Convertible Second Lien Notes (1)	10,814	23.9	%	8,534	24.1	%
Total	$11,944			$9,725		

(1) Interest expense for the year ended December 31, 2018 includes $4.1 million of debt discount amortization and $6.7 million of PIK interest, and interest expense for the year ended December 31, 2017 includes $2.6 million of debt discount amortization and $5.8 million of PIK interest.

2017 Senior 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 (as amended, 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) December 30, 2019, if the Convertible Second Lien Notes (as defined below) have not been voluntarily redeemed, repurchased, refinanced or otherwise retired by December 30, 2019. The maximum credit amount under the 2017 Senior Credit Facility is currently $250.0 million with a borrowing base of $75.0 million, subject to an elected draw limit of $50.0 million. The borrowing base is scheduled to be redetermined in March and September of each calendar year, 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 plus availability under the current borrowing base 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 PV-10 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) 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.

Convertible Second Lien Notes

On October 12, 2016, upon emergence from bankruptcy, 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 13.50% Convertible Second Lien Senior Secured Notes due 2019 (“Convertible Second Lien Notes”).

The aggregate principal amount of the Convertible Second Lien Notes is convertible at the option of the Purchasers at any time prior to the scheduled maturity date at $21.33 per share representing 1.9 million shares of the Company's common stock, subject to adjustments. At closing, the Purchasers were issued 10-year costless warrants equal to 2.5 million shares of common stock. Holders of the Convertible Second Lien Notes have a second priority lien on all assets of the Company, and have a continuing right to appoint two members to our Board of Directors as long as the Convertible Second Lien Notes are outstanding.

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The Convertible Second Lien Notes, as set forth in the agreement, were to mature on August 30, 2019 or six months after the maturity of our current revolving credit facility but in no event later than March 30, 2020. The 2017 Senior Credit Facility matures no earlier than December 30, 2019; consequently, the Convertible Second Lien Notes will mature on 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 are not convertible. During such time as the Exit Credit Agreement (but not any refinancing or replacement thereof) is in effect, interest on the Convertible Second Lien Notes must be paid in-kind; provided however, that after the quarter ending March 31, 2018, if (i) there is no default, event of default or borrowing base deficiency that has occurred and is continuing, (ii) the ratio of total debt to EBITDAX as defined under the 2017 Senior Credit Facility is less than 1.75 to 1.0 and (iii) the unused borrowing base is at least 25%, then the Company can pay the interest on the Convertible Second Lien Notes in cash, at its election.

The Indenture governing the Second Lien Notes contains certain covenants pertaining to us and our subsidiary, including delivery of financial reports; environmental matters; conduct of business; use of proceeds; operation and maintenance of properties; collateral and guarantee requirements; indebtedness; liens; dividends and distributions; limits on sale of assets and stock; business activities; transactions with affiliates; and changes of control.

The Indenture also contains certain financial covenants, including the maintenance of (i) a Total Proved Asset Coverage Ratio (as defined in the Exit Credit Agreement) not to be less than 1.50 to 1.00 after September 31, 2017, to be determined as of January 1 and July 1 of each year and (ii) minimum liquidity requirements.

Upon issuance of the Convertible Second Lien Notes in October 2016, in accordance with accounting standards related to convertible debt instruments that may be settled in cash upon conversion as well as warrants on the debt instrument, we recorded a debt discount of $11.0 million, thereby reducing the $40.0 million carrying value upon issuance to $29.0 million and recorded an equity component of $11.0 million. The debt discount is amortized using the effective interest rate method based upon an original term through August 30, 2019. As of December 31, 2018, $3.9 million of debt discount remains to be amortized on the Convertible Second Lien Notes.

As of December 31, 2018, we were in compliance with all covenants within the Indenture that governs the Second Lien Notes.

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, 2018. In addition to the contractual obligations presented in the table below, our Consolidated Balance Sheet at December 31, 2018 reflects accrued interest on our bank debt of $0.4 million payable in the first quarter of 2019. 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**	**2019**	**2020**	**2021**	**2022**	**2023 and After**
Debt	5	$85,664	$-	$58,664	$27,000	$ -	$ -
Office space leases		3,427	1,373	1,541	513	-	-
Operations contracts		2,395	2,380	15	-	-	-
Total contractual obligations (1)		$91,486	$3,753	$60,220	$27,513	$ -	$ -

(1) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $3.8 million as of December 31, 2018. 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.

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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, 2018 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.

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.

We follow 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, we use 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. We review our unevaluated properties at the end of each quarter to determine whether the costs should be reclassified to proved oil and gas properties and therefore subject to DD&A. Our sales of oil and gas properties are accounted for as adjustments to net proved oil and gas properties with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves. 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 capitalized, and DD&A expense is 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. 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.

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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.

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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 have entered into natural gas and oil derivative instruments in order to reduce the price risk associated with production in 2019 of approximately 72,500 MMBtu per day and 313 barrels per day, respectively, and in the first quarter of 2020 of 40,000 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 net liability position by $8.2 million and decreased the derivative oil asset position to a liability position of $0.1 million as of December 31, 2018. Likewise, a hypothetical decrease of 10% in the underlying commodity prices would have changed the derivative gas net liability position to a net asset position of $8.4 million and increased the derivative oil asset by $0.5 million as of December 31, 2018. 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, 2018, we had $27.0 million outstanding variable-rate debt and $49.8 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, 2018 and 2017, 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.

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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, 2018.

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 sheets of Goodrich Petroleum Corporation and subsidiary (the “Company”) as of December 31, 2018 and 2017, the related consolidated statements of operations, stockholders’ equity and cash flows for the years then ended, 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, 2018 and 2017, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

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 audits. 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 audits 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 audits 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 audits 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 audits 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 audits provide a reasonable basis for our opinion.

/s/ Moss Adams LLP

Houston, Texas
March 5, 2019

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

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS

(In Thousands)

	December 31, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 4,068	$ 25,992
Accounts receivable, trade and other, net of allowance	744	1,371
Accrued oil and natural gas revenue	14,464	4,958
Fair value of oil and natural gas derivatives	803	2,034
Inventory	596	2,521
Prepaid expenses and other	533	1,614
Total current assets	21,208	38,490
PROPERTY AND EQUIPMENT:		
Unevaluated properties	180	5,984
Oil and gas properties (full cost method)	206,097	120,333
Furniture, fixtures and equipment	1,360	1,039
	207,637	127,356
Less: Accumulated depletion, depreciation and amortization	(42,447)	(15,899)
Net property and equipment	165,190	111,457
Fair value of oil and natural gas derivatives	-	566
Deferred tax asset	786	937
Other	580	691
TOTAL ASSETS	$ 187,764	$ 152,141
LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable	$ 25,734	$ 17,204
Accrued liabilities	16,518	18,075
Fair value of oil and natural gas derivatives	-	1,002
Total current liabilities	42,252	36,281
Long term debt, net	76,820	55,725
Accrued abandonment costs	3,791	3,367
Fair value of oil and natural gas derivatives	471	517
Total liabilities	123,334	95,890
Commitments and contingencies (See Note 10)		
STOCKHOLDERS' EQUITY:		
Preferred stock: 10,000,000 shares $1.00 par value authorized, and none issued and outstanding	-	-
Common stock: $0.01 par value, 75,000,000 shares authorized, and 12,150,918 shares issued and outstanding at December 31, 2018 and $0.01 par value, 75,000,000 shares authorized, and 10,770,962 shares issued and outstanding at December 31, 2017	122	108
Additional paid in capital	74,861	68,446

Accumulated deficit	(10,553)	(12,303)
Total stockholders’ equity	64,430	56,251
TOTAL LIABILITIES AND STOCKHOLDERS’ EQUITY	$ 187,764	$ 152,141

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In Thousands, Except Per Share Amounts)

	Year ended December 31, 2018	**Year ended December 31, 2017**
REVENUES:		
Oil and natural gas revenues	$ 87,943	$ 45,320
Other	53	833
	87,996	46,153
OPERATING EXPENSES:		
Lease operating expense	10,446	12,125
Production and other taxes	2,605	1,183
Transportation and processing	11,046	6,222
Depreciation, depletion, and amortization	26,809	12,125
General and administrative	19,663	16,696
Other	7	(43)
	70,576	48,308
Operating income (loss)	17,420	(2,155)
OTHER INCOME (EXPENSE):		
Interest expense	(11,944)	(9,725)
Interest income and other	508	1,236
Gain (loss) on derivatives not designated as hedges	(3,986)	1,552
	(15,422)	(6,937)
Reorganization items, net	(305)	118
Income (loss) before income taxes	1,693	(8,974)
Income tax benefit	57	978
Net income (loss)	$ 1,750	$ (7,996)
PER COMMON SHARE:		
Net income (loss) per common share—basic	$ 0.15	$ (0.80)
Net income (loss) per common share—diluted	$ 0.13	$ (0.80)
Weighted average shares of common stock outstanding—basic	11,622	9,975
Weighted average shares of common stock outstanding—diluted	13,665	9,975

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)

	Year ended December 31, 2018	**Year ended December 31, 2017**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$1,750	$(7,996)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and amortization	26,809	12,125
Deferred income taxes	(57)	(937)
(Gain) loss on derivatives not designated as hedges	3,986	(1,552)
Net cash received (paid) in settlement of derivative instruments	(3,236)	471
Share-based compensation (non-cash)	6,545	6,863
Amortization of finance cost and debt discount	10,983	8,534
Reorganization items (non-cash)	(476)	(1)
Gain from material transfers	(32)	(367)
Change in assets and liabilities:		
Accounts receivable, trade and other, net of allowance	835	627
Accrued oil and natural gas revenue	(9,506)	(1,816)
Prepaid expenses and other	(249)	(881)
Accounts payable	8,530	1,888
Accrued liabilities	3,304	1,348
Net cash provided by operating activities	49,186	18,306
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(105,088)	(28,763)
Proceeds from sale of assets	26,839	563
Net cash used in investing activities	(78,249)	(28,200)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Principal payments of bank borrowings	(16,723)	(16,651)
Proceeds from bank borrowings	27,000	16,723
Issuance cost, net	(49)	(1,036)
Purchase of treasury stock	(3,089)	-
Net cash provided by (used in) financing activities	7,139	(964)
Decrease in cash and cash equivalents	(21,924)	(10,858)
Cash and cash equivalents, beginning of period	25,992	36,850
Cash and cash equivalents, end of period	$4,068	$25,992
Supplemental disclosures of cash flow information:		
Cash paid during the year for interest	$575	$1,228
Cash paid during the year for taxes	$-	$-

Increase (decrease) in non-cash capital expenditures	$(2,425)	$9,863

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY/(DEFICIT)

(In Thousands)

	Preferred Stock Shares	**Preferred Stock Value**	**Common Stock Shares**	**Common Stock Value**	**Additional Paid-in Capital**	**Treasury Stock Shares**	**Treasury Stock Value**	**Retained Earnings/ (Deficit)**	**Total Stockholders' Equity/(Deficit)**
Balance at December 31, 2016	-	$ -	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 & other	-	-	232	2	(2)	-	-	-	-
Convertible Second Lien Notes warrants and conversions	-	-	1,430	15	(158)	(1)	(7)	-	(150)
Issuance cost	-	-	-	-	(37)	-	-	-	(37)
Treasury stock activity	-	-	-	-	(931)	1	7	-	(924)
Balance at December 31, 2017	-	-	10,771	108	68,446	-	-	(12,303)	56,251
Net income	-	-	-	-	-	-	-	1,750	1,750
Share-based compensation	-	-	-	-	7,322	-	-	-	7,322
Restricted stock vesting & other	-	-	690	7	2,186	(230)	(2,970)	-	(777)
Convertible Second Lien Notes warrants and conversions	-	-	920	9	(5)	-	-	-	4
Issuance cost	-	-	-	-	(120)	-	-	-	(120)
Treasury stock activity	-	-	(230)	(2)	(2,968)	230	2,970	-	-
Balance at December 31, 2018	-	$ -	12,151	$ 122	$ 74,861	-	$ -	$ (10,553)	$ 64,430

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2018 and 2017 (in thousands):

	December 31,	
	2018	2017
Trade Payables	$8,633	$4,092
Revenue Payables	16,665	10,692
Prepayments from Partners	132	2,193
Other	304	227
Total Accounts Payable	$25,734	$17,204

Accrued Liabilities—Accrued liabilities consisted of the following items as of December 31, 2018 and 2017 (in thousands):

	December 31,	
	2018	2017
Accrued capital expenditures	$8,086	$10,511
Accrued lease operating expense	1,100	786
Accrued production and other taxes	338	449
Accrued transportation and gathering	1,888	1,130
Accrued performance bonus	3,420	3,869
Accrued interest	443	244
Accrued office lease	598	696
Accrued reorganization costs	-	168
Accrued general and administrative expense and other	645	222
	$16,518	$18,075

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.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Property and Equipment—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 depreciation, depletion and amortization ("DD&A") expense and the assessment of impairment of oil and gas properties. We have 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.

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 therefore subject to DD&A and the full cost ceiling test. For the years ended December 31, 2018 and December 31, 2017, we transferred $6.0 million and $18.8 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.

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.

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, 2018 and December 31, 2017 resulted in no write-down of the oil and gas properties.

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.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 2017 Senior Credit Facility and commodity derivatives whose fair values are based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our creditworthiness or that of our counterparties; and
- Level 3 Inputs- unobservable inputs for the asset or liability, such as discounted cash flow models or valuations, based on our various assumptions and future commodity prices. Included in this Level would be our initial measurement of asset retirement obligations.

As of December 31, 2018 and December 31, 2017, 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 initial measurement of the asset retirement obligations was classified as Level 3 in the fair value hierarchy.

Revenue Recognition—Oil and natural gas revenues are generally recognized upon delivery of our produced oil and natural gas volumes to our customers. We record revenue in the month our production is delivered to the purchaser. However, settlement statements and payments for our oil and natural gas sales may not be received for up to 60 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. 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, 2018 and 2017, 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*.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Net Income or Net Loss Per Common Share—Basic net income (loss) per common share is computed by dividing net income (loss) applicable to common stock for each reporting period by the weighted-average shares of common stock outstanding during the period. Diluted net income (loss) per common share is computed by dividing net income (loss) applicable to common stock for each reporting period by the weighted-average shares of common stock 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*.

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, 2018 and 2017 are as follows:

	Year Ended December 31,	
	2018	**2017**
CIMA Energy, LP	41%	0 %
ETC	15%	15%
Genesis Crude Oil LP	13%	20%
Sunoco, Inc.	4 %	13%
Williams Energy Resources LLC	1 %	29%
Occidental Energy MA	1 %	7 %

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 December 31, 2018 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", for which the due date has been extended to March 30, 2020).

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

In October 2018, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2018-16, Derivatives and Hedging (Topic 815): Inclusion of the Secured Overnight Financing Rate ("SOFR") Overnight Index Swap ("OIS") Rate as a Benchmark Interest Rate for Hedge Accounting Purposes. The amendments in this ASU permit use of the OIS rate based on SOFR as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815 in addition to the UST, the LIBOR swap rate, the OIS rate based on the Fed Funds Effective Rate, and the SIFMA Municipal Swap Rate. For entities that have not already adopted ASU 2017-12, as discussed below, the amendments in this ASU are required to be adopted concurrently with the amendments in Update 2017-12. The amendments should be adopted on a prospective basis for qualifying new or redesignated hedging relationships entered into on or after the date of adoption. 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 August 28, 2018, the FASB issued ASU 2018-13, Fair Value Measurements (Topic 820): Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement. The amendments in this ASU modify the disclosure requirements on fair value measurements in Topic 820 including the removal, modification and addition of certain disclosure requirements. For all entities, the amendments in this ASU are effective for fiscal periods beginning after December 15, 2019, including interim periods therein. We are evaluating the expected impact these amendments will have on our consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On June 20, 2018, the FASB issued ASU 2018-07, Compensation—Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting. The amendments in this ASU expand the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees. The amendments specify that Topic 718 applies to all share-based payment transactions in which a grantor acquires goods or services to be used or consumed in a grantor’s own operations by issuing share-based payment awards. The amendments also clarify that Topic 718 does not apply to share-based payments used to effectively provide (1) financing to the issuer or (2) awards granted in conjunction with selling goods or services to customers as part of a contract accounted for under Topic 606, Revenue from Contracts with Customers. For public entities, the amendments in this ASU are effective for annual periods beginning after December 15, 2018. We have not granted or issued share-based payments to nonemployees. We have evaluated the provisions of this ASU and do not expect it to have a material impact on our consolidated financial statements.

On March 13, 2018, the FASB issued ASU 2018-05, Income Taxes (Topic 740). The ASU adds seven paragraphs to the Accounting Standards Codification “ASC” 740, Income Taxes, that contain SEC guidance related to Staff Accounting Bulletin 118 (“Income Tax Accounting Implications of the Tax Cuts and Jobs Act”) as a result of the tax legislation passed in 2017 known as the “Tax Cuts and Jobs Act” (the “Act”). Specifically, the staff intended to address situations where the accounting under ASC Topic 740 is incomplete for certain income tax effects of the Act upon issuance of an entity’s financial statements for the reporting period in which the Act was enacted. The Company notes that it has considered the updates to ASC 740 as a result of the Act and has prepared its consolidated financial statements in accordance with the Act. See Note 7 for further discussion.

On August 28, 2017, the FASB issued 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 February 25, 2016, the FASB issued ASU 2016-02, Leases (Topic 842) and subsequently issued ASU 2018-10, Codification Improvements to Topic 842, Leases and ASU 2018-11, Leases (Topic 842): Targeted Improvements in July 2018. The intent of these ASU's is to increase transparency and comparability among organizations by recognizing right-of-use lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The key difference between the existing standards and ASU 2016-02 is the requirement for lessees to recognize on their balance sheet all lease contracts with lease terms greater than 12 months, including operating leases. Specifically, lessees are required to recognize on the balance sheet at lease commencement, both (i) a right-of-use asset, representing the lessee’s right to use the leased asset over the term of the lease, and (ii) a lease liability, representing the lessee’s contractual obligation to make lease payments over the term of the lease. For lessees, ASU 2016-02 requires classification of leases as either operating or finance leases, which are similar to the current operating and capital lease classifications. However, the distinction between these two classifications under the ASU does not relate to balance sheet treatment but relates to treatment and recognition in the statements of income and cash flows. Lessor accounting is largely unchanged from current US GAAP. The amendments are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, for public entities. Early application is permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach with the option to adopt certain practical expedients, or apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The Company is carrying out its project plan to guide the implementation of ASU 2016-02, which includes assessing our portfolio of leases, determining a process for ensuring completeness of our repository of active leases, determining financial statement impacts and preparing for disclosure requirements under Topic 842. The Company will adopt this guidance as of January 1, 2019 using the transition method that allows a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. We have elected the transition relief package of practical expedients and will apply previous accounting conclusions under ASC 840 to all of our leases that existed prior to the adoption date. The Company will elect the short-term practical expedient for all of our asset classes by establishing an accounting policy to exclude leases with a term of 12 months or less. The Company will also adopt the easement practical expedient which allows the Company to apply the new guidance prospectively to land easements after the adoption date. Easements that existed or expired prior to the adoption date that were not previously assessed under ASC 840 will not be reassessed. We do expect to recognize right-of-use assets and corresponding lease liabilities for our operating leases with terms longer than 12 months of approximately $5.0 million on the Consolidated Balance Sheets upon adoption.

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NOTE 2—Revenue Recognition

On January 1, 2018, we adopted ASU 2014-09, *Revenue from Contracts with Customers,* and the series of related ASU's that followed under ASC Topic 606 (collectively, "Topic 606"). Under Topic 606, revenue will generally be recognized upon delivery of our produced oil and natural gas volumes to our customers. Our customer sales contracts include oil and natural gas sales. Under Topic 606, each unit (Mcf or barrel) of commodity product represents a separate performance obligation which is sold at variable prices, determinable on a monthly basis. The pricing provisions of our contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, product quality and prevailing supply and demand conditions in the geographic areas in which we operate. We will allocate the transaction price to each performance obligation and recognize revenue upon delivery of the commodity product when the customer obtains control. Control of our produced natural gas volumes passes to our customers at specific metered points indicated in our natural gas contracts. Similarly, control of our produced oil volumes passes to our customers when the oil is measured either by a trucking oil ticket or by a meter when entering an oil pipeline. The Company has no control over the commodities after those points and the measurement at those points dictates the amount on which the customer's payment is based. Our oil and natural gas revenue streams include volumes burdened by royalty and other joint owner working interests. Our revenues are recorded and presented on our financial statements net of the royalty and other joint owner working interests. Our revenue stream does not include any payments for services or ancillary items other than sale of oil and natural gas.

We record revenue in the month our production is delivered to the purchaser. However, settlement statements and payments for our oil and natural gas sales may not be received for up to 60 days after the date production is delivered, and as a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized. As of December 31, 2018 and December 31, 2017, receivables from contracts with customers were $14.5 million and $5.0 million, respectively.

Topic 606 will not change our pattern of timing of revenue recognition. We utilized the full retrospective method for adoption of Topic 606, and in accordance with this method our consolidated financial statements for periods prior to January 1, 2018 were not materially affected or revised. We also do not anticipate a material impact on our financial statements on an ongoing basis.

The following tables present our oil and natural gas revenues disaggregated by revenue source and by operated and non-operated properties:

	Year Ended December 31, 2018			
(In thousands)	**Oil Revenue**	**Gas Revenue**	**NGL Revenue**	**Total Oil and Natural Gas Revenues**
Operated	$ 14,189	$ 58,911	$ -	$ 73,100
Non-operated	556	14,236	51	14,843
Total oil and natural gas revenues	$ 14,745	$ 73,147	$ 51	$ 87,943

	Year Ended December 31, 2017			
(In thousands)	**Oil Revenue**	**Gas Revenue**	**NGL Revenue**	**Total Oil and Natural Gas Revenues**
Operated	$ 14,973	$ 17,137	$ -	$ 32,110
Non-operated	518	12,673	19	13,210
Total oil and natural gas revenues	$ 15,491	$ 29,810	$ 19	$ 45,320

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NOTE 3—Share-based Compensation Plans

Overview

The Company had one effective share-based compensation plan as of December 31, 2018 and December 31, 2017, which is the 2016 Long Term Incentive Plan, discussed further below. We measure the cost of share-based compensation based on the fair value of the award as of the grant date, net of estimated forfeitures. Awards granted are valued at fair value and recognized on a straight-line basis over the service periods (or the vesting periods) of each award. We estimate forfeiture rates for all unvested awards based on our historical experience.

2016 Long Term Incentive Plan

Our 2016 Long Term Incentive Plan (the "LTIP"), formerly referred to as the Management Incentive Plan (the "MIP"), provides for awards of restricted stock, options, performance awards, phantom shares and stock appreciation rights to directors, officers, employees, and consultants.

In May 2017, an additional 1.5 million shares under the LTIP were approved by our shareholders. During 2017, 0.5 million restricted stock units ("RSUs") were granted which vest over a service period of 3 years, except for grants to Directors which vested in 12 months. Additionally, 0.4 million performance stock units ("PSUs") were granted in December 2017 which cliff vest at the end of 3 years.

In 2018, with the exception of utilization of the LTIP for the issuance of 201,969 shares for the 2017 performance bonus paid in stock, there were no material issuances of RSUs granted to employees. In December 2018, 45,160 RSUs were granted to non-employee Directors which will vest in 12 months. The Company had 0.3 million shares under the LTIP approved and available for future issuance as of December 31, 2018, assuming that the PSUs awarded will vest at the maximum payout of 250%.

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

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

Performance Share Awards

In December 2017, the Company granted 402,679 PSUs. The performance awards have a service period of 3 years and contain predetermined market conditions established by the Compensation Committee, and, if the market and service conditions are met, will cliff vest 3 years from the date of grant. The number of shares to be earned is subject to a market condition, which is based on the total shareholder return ("TSR") of the Company's common stock relative to the TSR achieved by the Russell 2000 Energy Index at the end of the performance period as well as company stock price performance. The range of common stock shares which may be earned by an award recipient ranges from zero to 250% of the initial performance units granted. The grant date fair value of the PSUs was determined using a Monte Carlo simulation model. The assumptions used in the Monte Carlo simulation model are described below:

- Volatility factor - The volatility factor represents the extent to which the market price of the Company's common stock price is expected to fluctuate between the grant date and the end of the performance period.
- Dividend yield - The dividend yield on the Company's common stock is assumed to be zero since the Company does not currently pay dividends and does not anticipate paying dividends in the future.
- Risk-free interest rate - The risk-free interest rate is based upon the yield of US Treasuries with a three year term.
- Expected term - The expected term represents the period of time that the PSUs will be outstanding, which is the grant date to the end of the performance period, or three years.

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The grant date fair value of each PSU as determined by the Monte Carlo simulation model was $15.29, which was based on the following assumptions:

	2017	
Number of simulations	100,000	
Grant price	$ 15.29	
Volatility factor	57	%
Dividend yield	—	
Risk-free interest rate	1.92	%
Expected term (in years)	P3Y	

The fair value of the PSUs of $6.2 million is amortized on a straight-line basis and recognized as share-based compensation expense, net of amounts capitalized, over the requisite service period of 3 years. All compensation cost related to the PSUs will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. As of December 31, 2018, unrecognized compensation costs related to the 399,388 unvested PSUs was $4.1 million and will be recognized as share-based compensation expense, net of amounts capitalized, over a weighted-average period of 1.96 years.

There were no grants of PSUs during the year ended December 31, 2018.

Share-based Compensation

The following tables summarizes the pre-tax components of our share-based compensation program under the LTIP, recognized as a component of general and administrative expenses in the Consolidated Statements of Operations (in thousands), for the years ended December 31, 2018 and 2017:

	Year Ended December 31,	
2016 Long Term Incentive Plan	**2018**	**2017**

RSU expense - employees	$4,702	$3,636
PSU expense	1,893	84
RSU expense - directors	595	738
Total share-based compensation	$7,190	$4,458
Capitalized share-based compensation	(747)	-
Net share-based compensation - general and administrative expense	$6,443	$4,458

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

Restricted stock activity and changes under the LTIP for the year ended December 31, 2018 and for the period from January 1, 2017 to December 31, 2018 are as follows:

2016 Long Term Incentive Plan	**Number of Units**			**Weighted Average Grant-Date Fair Value**			**Total Value (thousands)**		
	RSU	**PSU**	**Total**	**RSU**	**PSU**	**Total**	**RSU**	**PSU**	**Total**
Unvested at December 31, 2016	1,132,666	-	1,132,666	$10.08	$-	$10.08	$11,421	$-	$11,421
Granted	476,054	402,679	878,733	9.93	15.29	12.38	4,726	6,157	10,883
Vested	(413,436)	-	(413,436)	10.28	-	10.28	(4,213)	-	(4,213)
Forfeited	(23,931)	-	(23,931)	12.00	-	12.00	(287)	-	(287)
Unvested at December 31, 2017	1,171,353	402,679	1,574,032	9.91	15.29	11.29	11,647	6,157	17,804
Granted (1)	249,751	-	249,751	11.54	-	11.54	2,882	-	2,882
Vested (1)	(742,607)	-	(742,607)	10.20	-	10.20	(9,681)	-	(9,681)
Forfeited	(17,360)	(3,291)	(20,651)	11.25	15.29	11.90	(195)	(50)	(245)
Unvested at December 31, 2018	661,137	399,388	1,060,525	$10.16	$15.29	$12.09	$4,653	$6,107	$10,760

(1) Included 201,969 shares issued and vested for the 2017 performance bonus paid in stock in 2018.

As of December 31, 2018 and 2017, total unrecognized compensation cost and weighted average years to recognition related to RSUs and PSUs under the LTIP are as follows:

2016 Long Term Incentive Plan

	Unrecognized compensation costs (thousands)			Weighted Average years to recognition (years)		
	RSU	**PSU**	**Total**	**RSU**	**PSU**	**Total**
December 31, 2018	$6,340	$4,100	$10,440	1.35	1.96	1.59
December 31, 2017	$11,248	$6,070	$17,318	2.23	2.96	2.47

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NOTE 4—Asset Retirement Obligations

The table below is the reconciliation of the beginning and ending asset retirement obligation for the periods as noted (in thousands):

	December 31, 2018	**December 31, 2017**
Beginning balance	$ 3,367	$ 2,933
Liabilities incurred	303	132
Revisions in estimated liabilities (1)	47	71
Liabilities settled	(13)	-
Accretion expense	262	231
Dispositions (2)	(175)	-
Ending balance	$ 3,791	$ 3,367
Current liability	$ -	$ -
Long term liability	$ 3,791	$ 3,367

(1) Changes in estimated costs and timing of plugging and abandoning gave rise to the revision in estimated liabilities.

(2) See *Note 11* for further information on the dispositions during the year ended December 31, 2018.

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NOTE 5—Debt

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

	December 31, 2018			December 31, 2017		
	Principal	Carrying Amount	Fair Value	Principal	Carrying Amount (5)	Fair Value (1)
2017 Senior Credit Facility (1)	$27,000	$27,000	$27,000	$16,723	$16,723	$16,723
Convertible Second Lien Notes (2)	53,691	49,820	60,857	47,015	39,002	62,026
Total debt	$80,691	$76,820	$87,857	$63,738	$55,725	$78,749

(1) The carrying amount for the 2017 Senior Credit Facility represent fair value as it was 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 paid-in-kind ("PIK") interest of $13.7 million as of December 31, 2018 and $7.0 million as of December 31, 2017. The carrying value includes $3.9 million and $8.0 million of unamortized debt discount at December 31, 2018 and 2017, respectively. The fair value of the Convertible Second Lien Notes, a Level 2 fair value estimate, was obtained by using the last known sale price for the value on December 31, 2018 and 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 as noted below:

	Year Ended December 31, 2018			Year Ended December 31, 2017		
	Interest Expense	Effective Interest Rate		Interest Expense	Effective Interest Rate	
Exit Credit Facility	$-	0	%	$947	7.1	%
2017 Senior Credit Facility	1,130	8.9	%	244	7.2	%
Convertible Second Lien Notes (1)	10,814	23.9	%	8,534	24.1	%

Total	$11,944	$9,725

(1) Interest expense for the year ended December 31, 2018 includes $4.1 million of debt discount amortization and $6.7 million of PIK interest, and interest expense for the year ended December 31, 2017 includes $2.6 million of debt discount amortization and $5.8 million of PIK interest.

Exit Credit Facility

On October 12, 2016, upon consummation of the plan of reorganization and 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, and certain other lenders party thereto. Pursuant to the Exit Credit Agreement, the lenders party thereto agreed to provide the Borrower with a $20.0 million senior secured term loan credit facility (the “Exit Credit Facility”). On October 17, 2017, the Exit Credit Facility was paid off in full and replaced with the 2017 Senior Credit Facility described below.

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2017 Senior Credit Facility

On October 17, 2017, the Company entered into the Amended and Restated Senior Secured Revolving Credit Agreement (as amended, the "Credit Agreement") with the Subsidiary, as borrower, JP Morgan Chase Bank, N.A. as administrative agent, and certain lenders that are party thereto, which provides for revolving loans of up to the borrowing base then in effect (as amended, the "2017 Senior Credit Facility"). The 2017 Senior Credit Facility amended, restated and refinanced the obligations under the Exit Credit Facility. The 2017 Senior Credit Facility matures (a) October 17, 2021 or (b) December 30, 2019, if the Convertible Second Lien Notes (as defined below) have not been voluntarily redeemed, repurchased, refinanced or otherwise retired by December 30, 2019. The maximum credit amount under the 2017 Senior Credit Facility at September 30, 2018 was $250.0 million with a borrowing base of $75.0 million, subject to an elected draw limit of $50.0 million in recognition of the limitation set forth in the Convertible Second Lien Notes. The borrowing base is scheduled to be redetermined in March and September of each calendar year, 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, each of the Borrower 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. We may, however, elect to reduce the proposed borrowing base to a lower draw limit by providing notice to the lenders contemporaneously with each redetermination of the borrowing base. The Company may also request the issuance of letters of credit under the Credit Agreement 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. As of December 31, 2018, the interest rates on the borrowings from the 2017 Senior Credit Facility were between 5.40% and 7.50%.

The 2017 Senior Credit Facility also contains certain financial covenants, including (i) the maintenance of a ratio of Total Debt (as defined in the Credit Agreement) to EBITDAX not to exceed 4.00 to 1.00 as of the last day of any fiscal quarter, (ii) in accordance with the second amendment to the Credit Agreement, beginning with the quarter ended December 31, 2018, a current ratio (based on the ratio of current assets plus availability under the current borrowing base 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 PV-10 attributable to the Company's and Borrower's Proved Reserves (as defined in the Credit Agreement) 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 and (B) minimum liquidity requirements.

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

As of December 31, 2018, the Company had a borrowing base of $75.0 million, subject to an elected draw limit of $50.0 million, with $27.0 million outstanding. The Company also had $0.5 million of unamortized debt issuance costs recorded as of December 31, 2018 related to the 2017 Senior Credit Facility.

As of December 31, 2018, we were in compliance with all covenants within the 2017 Senior Credit Facility.

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Convertible Second Lien Notes

On October 12, 2016, upon emergence from bankruptcy, 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 Convertible Second Lien Notes.

The aggregate principal amount of the Convertible Second Lien Notes is convertible at the option of the Purchasers at any time prior to the scheduled maturity date at $21.33 per share representing 1.9 million shares of the Company's common stock, subject to adjustments. At closing, the Purchasers were issued 10-year costless warrants equal to 2.5 million shares of common stock. Holders of the Convertible Second Lien Notes have a second priority lien on all assets of the Company, and have a continuing right to appoint two members to our Board of Directors (“Board”) as long as the Convertible Second Lien Notes are outstanding.

The Convertible Second Lien Notes, as set forth in the agreement, were to mature on August 30, 2019 or six months after the maturity of our current revolving credit facility but in no event later than March 30, 2020. The 2017 Senior Credit Facility matures no earlier than December 30, 2019; consequently, the Convertible Second Lien Notes will mature on 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 are not convertible. During such time as the Exit Credit Agreement (but not any refinancing or replacement thereof) is in effect, interest on the Convertible Second Lien Notes must be paid in-kind; provided however, that after the quarter ending March 31, 2018, if (i) there is no default, event of default or borrowing base deficiency that has occurred and is continuing, (ii) the ratio of total debt to EBITDAX as defined under the 2017 Senior Credit Facility is less than 1.75 to 1.0 and (iii) the unused borrowing base is at least 25%, then the Company can pay the interest on the Convertible Second Lien Notes in cash, at its election.

The Indenture governing the Second Lien Notes contains certain covenants pertaining to us and our subsidiary, including delivery of financial reports; environmental matters; conduct of business; use of proceeds; operation and maintenance of properties; collateral and guarantee requirements; indebtedness; liens; dividends and distributions; limits on sale of assets and stock; business activities; transactions with affiliates; and changes of control.

The Indenture also contains certain financial covenants, including the maintenance of (i) a Total Proved Asset Coverage Ratio (as defined in the Exit Credit Agreement) not to be less than 1.50 to 1.00 after September 31, 2017, to be determined as of January 1 and July 1 of each year and (ii) minimum liquidity requirements.

Upon issuance of the Convertible Second Lien Notes in October 2016, in accordance with accounting standards related to convertible debt instruments that may be settled in cash upon conversion as well as warrants on the debt instrument, we recorded a debt discount of $11.0 million, thereby reducing the $40.0 million carrying value upon issuance to $29.0 million and recorded an equity component of $11.0 million. The debt discount is amortized using the effective interest rate method based upon an original term through August 30, 2019. As of December 31, 2018, $3.9 million of debt discount remains to be amortized on the Convertible Second Lien Notes.

As of December 31, 2018, we were in compliance with all covenants within the Indenture that governs the Second Lien Notes.

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NOTE 6—Net Income (Loss) Per Common Share

Net income (loss) applicable to common stock was used as the numerator in computing basic and diluted net income (loss) per common share for the periods as noted below. The Company used the treasury stock method in determining the effects of potentially dilutive restricted stock. The following table sets forth information related to the computations of basic and diluted net income (loss) per common share:

	Year Ended December 31, 2018	**Year Ended December 31, 2017**
Basic net income (loss) per common share:		
Net income (loss) applicable to common stock	$ 1,750	$ (7,996)
Weighted-average shares of common stock outstanding	11,622	9,975
Basic net income (loss) per common share	$ 0.15	$ (0.80)
Diluted net income (loss) per common share:		
Net income (loss) applicable to common stock	$ 1,750	$ (7,996)
Weighted-average shares of common stock outstanding	11,622	9,975
Common shares issuable upon conversion of the Convertible Second Lien Notes associated warrants	150	-
Common shares issuable upon conversion of warrants of unsecured claim holders	1,418	-
Common shares issuable on assumed conversion of restricted stock	475	-
Diluted weighted average shares of common stock outstanding	13,665	9,975
Diluted net income (loss) per common share (1) (2) (3)	$ 0.13	$ (0.80)
(1) Common shares issuable on assumed conversion of share-based compensation were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive. **	-	243
(2) Common shares issuable upon conversion of the Convertible Second Lien Notes were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.	1,875	1,875
(3) Common shares issuable upon conversion of the warrants associated with the Convertible Second Lien Notes and unsecured claim holders were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.	-	2,459

** - Common shares issuable on assumed conversion of share-based compensation assumes a payout of the Company's performance share awards at 100% of the initial performance units granted (or a ratio of one unit to one common share). The range of common stock shares which may be earned ranges from zero to 250% of the initial performance units granted.

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NOTE 7—Income Taxes

The following table summarizes the tax benefit for the periods as noted below (in thousands):

	Year Ended December 31, 2018	**Year Ended December 31, 2017**
Current tax benefit		
Federal	$ (208)	$ (41)
State	-	-
Total current tax benefit	(208)	(41)
Deferred tax expense (benefit)		
Federal	151	(937)
State	-	-
Total deferred tax expense (benefit)	151	(937)
Total tax benefit	$ (57)	$ (978)

The following is a reconciliation of the U.S. statutory income tax rate at 21% to our income (loss) before income taxes (in thousands):

	Year Ended December 31, 2018	**Year Ended December 31, 2017**
Income tax expense (benefit)		
Tax expense (benefit) at U.S. statutory rate	$ 356	$ (3,141)
Disallowed executive compensation	841	-
Rate change	-	41,175
Valuation allowance for remeasurement and changes relating to the Act	-	(42,112)
Valuation allowance	(2,530)	5,474
State income taxes, net of federal benefit	1,194	(861)

Nondeductible expenses and other	82	(1,513)
Total tax benefit	$ (57)	$ (978)

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are presented below (in thousands) for the years ended December 31, 2018 and 2017:

	December 31,	
	2018	**2017**
Non-current deferred tax assets:		
Operating loss carry-forwards	$38,958	$27,136
State tax NOL and credits	10,278	8,060
Statutory depletion carry-forward	4,221	4,221
AMT tax credit carry-forward	786	1,008
Compensation	1,426	1,170
Contingent liabilities and other	784	298
Other	-	-
Debt discount	54	173
Property and equipment	28,530	45,809
Total gross non-current deferred tax assets	85,037	87,875
Less valuation allowance	(84,181)	(86,711)
Net non-current deferred tax assets	856	1,164
Non-current deferred tax liabilities:		
Derivatives	(70)	(227)
Total non-current deferred tax liabilities	(70)	(227)
Net non-current deferred tax asset	$786	$937

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 completed the accounting for the effects of the Act during 2017. Our financial statements for the year ended December 31, 2017 reflected certain effects of the Act which included a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018, as well as other changes. Due to the Company’s valuation allowance position and as a result of changes to tax laws and rates under the Act, the Company recorded a net $1.0 million tax benefit for the year ended December 31, 2017, due primarily to the remeasurement of deferred tax assets and liabilities from 35% to 21% and the removal of the valuation allowance on the estimated refundable Alternative Minimum Tax (“AMT”) credits after sequestration. The valuation allowance decreased by $42.1 million in 2017 due to the changes to tax laws and rates under the Act and increased by $5.5 million for normal operations. The valuation allowance decreased by $2.5 million in 2018 primarily relating to normal operations. The Company recorded a $0.1 million income tax benefit for the year ended December 31, 2018 as the sequestration of AMT credits is no longer anticipated for future tax years.

The Company followed the guidance in SEC Staff Accounting Bulletin 118 (“SAB 118”) for the year ended December 31, 2017, which provides additional clarification regarding the application of ASC Topic 740 in situations where the Company does not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the accounting for certain income tax effects of the Act for the reporting period in which the Act was enacted. SAB 118 provides for a measurement period beginning in the reporting period that includes the Act’s enactment date and ending when the Company has obtained, prepared, and analyzed the information needed in order to complete the accounting requirements but in no circumstances should the measurement period extend beyond one year from the enactment date. We calculated the impact of the Act in the year end December 31, 2017 tax provision in accordance with our understanding of the Act and guidance available as of the date of the filing. The Company booked no provisional amounts as of December 31, 2017 with respect to the Act and no further adjustments were required during 2018.

We have recorded a valuation allowance of $84.1 million at December 31, 2018, which resulted in a net non-current deferred tax asset of $0.8 million appearing on our statement of financial position. We recorded this valuation allowance at this date after an evaluation of all available evidence (including our recent history of net operating losses in 2017 and prior years) that led to a conclusion that based upon the more-likely-than-not standard of the accounting literature, these deferred tax assets were unrecoverable. The tax benefits recorded for 2018 and 2017 were due to AMT credits that are expected to be recognized by the Company. AMT credits were partially monetized in 2016, and the Company has a receivable recorded for $0.2 million for the AMT credits related to monetized amounts on the 2017 tax return. The remaining $0.8 million of AMT credits are expected to be fully refundable in tax years 2018 - 2021 regardless of the Company's regular tax liability as a result of the repeal of the Corporate AMT under the Act. The Company no longer has a valuation recorded against our estimate of refundable AMT credits.

As of December 31, 2018, we have federal net operating loss carry-forwards of approximately $815.4 million. These carry-forwards are subject to IRC Section 382 and it is estimated $185.5 million will be available to offset future U.S taxable income.

IRC Sections 382 and 383 provide an annual limitation with respect to the ability of a corporation to utilize its tax attributes, as well as certain built-in losses, against future U.S. taxable income in the event of a change in ownership. The Company's emergence from bankruptcy in October 2016 was considered a change in ownership for purposes of IRC Section 382. The limitation under the tax code is based on the value of the Company when it emerged from bankruptcy on October 12, 2016. This ownership change resulted in limitation which will eliminate an estimated $630.7 million of federal net operating losses previously available to offset future U.S. taxable income. The Company also has net operating losses in Louisiana and Mississippi which will be subject to limitation due to the ownership change. The Company estimates state net operating losses ("NOLs") available for use of $71.7 million in Louisiana and $126.1 million in Mississippi after the reduction for unusable NOLs due to the ownership change.

We did not have any unrecognized tax benefits as of December 31, 2018. The amount of unrecognized tax benefits may change in the next twelve months; however we do not expect the change to have a significant impact on our results of operations or our financial position. We file a consolidated federal income tax return in the United States and various combined and separate filings in several state and local jurisdictions. With limited exceptions, we are no longer subject to U.S. Federal, state and local, or non-U.S. income tax examinations by tax authorities for years before 2010.

Our continuing practice is to recognize estimated interest and penalties related to potential underpayment on any unrecognized tax benefits as a component of income tax expense in the Consolidated Statement of Operations. We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations before December 31, 2018.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 8—Stockholders' Equity

At December 31, 2018 there were 12,150,918 shares of our Company common stock outstanding and 75,000,000 shares authorized at $0.01 par value per share.

During the year ended December 31, 2018, certain holders of the 10 year costless warrants associated with the Convertible Second Lien Notes exercised 920,312 warrants for the issuance of an equal amount of our one cent par value common stock. The Company received cash for the one cent par value for the issuance of 373,437 common shares. As of December 31, 2018, 150,000 of such warrants remain un-exercised. During the year ended December 31, 2018, the Company issued 201,969 common shares under utilization of the LTIP for the portion of the 2017 performance bonus paid in stock. Also during the year ended December 31, 2018, the Company paid $3.1 million in cash for the purchase of 230,013 Treasury shares withheld from employees upon the vesting of restricted stock awards and performance bonus shares for the payments of taxes. The shares held in treasury stock were retired before December 31, 2018.

During the year ended December 31, 2017, certain holders of the 10 year costless warrants associated with the Convertible Second Lien Notes exercised 1,429,687 warrants for the issuance of an equal amount of our one cent par value common stock. The Company received cash for the one cent par value for issuance of 679,687 common shares and the remaining common shares were issued cashless, which resulted in 564 shares repurchased by the Company and held in treasury stock. The 564 shares held in treasury stock were retired before December 31, 2017. As of December 31, 2017, 1,070,312 of such warrants had remained un-exercised.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 9—Derivative Activities

We use commodity and financial derivative contracts to manage fluctuations in commodity prices and interest rates. We are currently not designating our derivative contracts for hedge accounting. All derivative gains and losses during 2018 and 2017 are from our oil and natural gas derivative contracts and have been recognized in "Other income (expense)" on our Consolidated Statements of Operations.

The following table summarizes the gains and losses we recognized on our oil and natural gas derivatives for the periods as noted below:

Oil and Natural Gas Derivatives (in thousands)	**Year Ended December 31, 2018**	**Year Ended December 31, 2017**
Gain (loss) on commodity derivatives not designated as hedges, settled	$ (3,236)	$ 471
Gain (loss) on commodity derivatives not designated as hedges, not settled	(750)	1,081
Total gain (loss) on commodity derivatives not designated as hedges	$ (3,986)	$ 1,552

Commodity Derivative Activity

We enter into swap contracts, costless collars or other derivative agreements from time to time to manage commodity price risk for a portion of our production. Our policy is that all derivative contracts are approved by the Hedging Committee of our Board of Directors and reviewed periodically by the Board of Directors.

Despite the measures taken by us to attempt to control price risk, we remain subject to price fluctuations for natural gas and crude oil sold in the spot market. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Decreases in domestic crude oil and natural gas spot prices will have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis. We routinely exercise our contractual right to net realized gains against realized losses when settling with our financial counterparties. Neither our counterparties nor we require any collateral upon entering into derivative contracts. We would have been at risk of losing $0.5 million had JPMorgan Chase Bank, N.A. and SunTrust Bank been unable to fulfill their obligations as of December 31, 2018.

As of December 31, 2018, the open positions on our outstanding commodity derivative contracts, all of which were with JPMorgan Chase Bank, N.A. and SunTrust Bank, were as follows:

Contract Type	**Average Daily Volume**	**Total Volume**	**Fixed Price**	**December 31, 2018**
Crude oil swaps (Bbls)				
2019	312	114,025	$51.80	$ 431
			Total oil	431
Natural gas swaps and calls (MMBtu)				
2020	40,000	3,640,000	$2.81	(471)
2019	72,466	26,450,000	$2.81-$3.033	372
			Total natural gas	(99)
			Total	$ 332

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes the fair values of our derivative financial instruments that are recorded at fair value classified in each level as of December 31, 2018 (in thousands). We measure the fair value of our commodity derivative contracts by applying the income approach. See *Note 1 "Description of Business and Summary of Significant Accounting Policies"* for our discussion regarding fair value, including inputs used and valuation techniques for determining fair values.

Description	**Level 1**	**Level 2**	**Level 3**	**Total**
Fair value of oil and natural gas derivatives - Current Assets	$ -	$803	$ -	$803
Fair value of oil and natural gas derivatives - Non-current Assets	-	-	-	-
Fair value of oil and natural gas derivatives - Current Liabilities	-	-	-	-
Fair value of oil and natural gas derivatives - Non-current Liabilities	-	(471)	-	(471)
Total	$ -	$332	$ -	$332

We enter into oil and natural gas derivative contracts under which we have netting arrangements with each counter-party. The following table discloses and reconciles the gross amounts to the amounts as presented on the Consolidated Balance Sheets for the periods ending December 31, 2018:

Fair Value of Oil and Natural Gas Derivatives (in thousands)	**December 31, 2018**		
	Gross Amount	**Amount Offset**	**As Presented**
Fair value of oil and natural gas derivatives - Current Assets	$2,893	$(2,090)	$ 803
Fair value of oil and natural gas derivatives - Non-current Assets	-	-	-
Fair value of oil and natural gas derivatives - Current Liabilities	(2,090)	2,090	-
Fair value of oil and natural gas derivatives - Non-current Liabilities	(471)	-	(471)
Total	$332	$-	$ 332

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 10—Commitments and Contingencies

We are party to various lawsuits from time to time arising in the normal course of business, including, but not limited to, royalty, contract, personal injury, and environmental claims. We have established reserves as appropriate for all such proceedings and intend to vigorously defend these actions. Management believes, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to our consolidated financial position results of operations, cash flows or liquidity.

The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2018 (in thousands):

	Payment due by Period						
	Note	**Total**	**2019**	**2020**	**2021**	**2022**	**2023 and After**
Debt	5	$85,664	$-	$58,664	$27,000	$ -	$ -
Office space leases		3,427	1,373	1,541	513	-	-
Operations contracts		2,395	2,380	15	-	-	-
Total contractual obligations (1)		$91,486	$3,753	$60,220	$27,513	$ -	$ -

(1) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $3.8 million as of December 31, 2018. We record a separate liability for the asset retirement obligations. See Note 4.

Operating Leases—We have commitments under an operating lease agreements for office space and office equipment leases. Total rent expense for the years ended December 31, 2018, and 2017 was approximately $1.6 million and $1.7 million, respectively.

NOTE 11—Dispositions and Acquisitions

On May 21, 2018, the Company closed on the sale of working interests in certain oil and gas leases, including wells, facilities and leasehold acres in our Tuscaloosa Marine Shale Trend operating area located in East and West Feliciana Parish, Louisiana for total consideration of approximately $3.3 million with an effective date of May 1, 2018. The disposition was subject to customary post-closing adjustments. The disposition was recorded as a reduction to our oil and natural gas properties (full cost method) on our Consolidated Balance Sheets.

On February 28, 2018, the Company closed, in two separate transactions, the sale of working interests in certain oil and gas leases, wells, units and facilities and certain net leasehold interests in a portion of its undeveloped acreage in the Angelina River Trend in Angelina and Nacogdoches Counties, Texas for total consideration of $23.0 million, with an effective date of January 1, 2018. The disposition was subject to customary post-closing adjustments. The disposition was recorded as a reduction to our oil and natural gas properties (full cost method) on our Consolidated Balance Sheets. The Company utilized the proceeds from these dispositions to pay down the outstanding balance of the 2017 Senior Credit Facility on March 2, 2018 and to fund our capital expenditures program.

The Company also sold other miscellaneous acreage during the year ended December 31, 2018 for $0.7 million, which was also recorded as a reduction to our oil and natural gas properties (full cost method) on our Consolidated Balance Sheets.

During 2017, we closed on various sales of undeveloped non-core mineral interest which resulted in $0.6 million in cash receipts that were recorded as a reduction of the Full Cost Pool.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

SUPPLEMENTAL INFORMATION

(Unaudited)

Oil and Natural Gas Producing Activities (Unaudited)

Overview

All of our reserve information related to crude oil, condensate and natural gas was compiled based on estimates prepared and reviewed by our engineers. The technical persons primarily responsible for overseeing the preparation of the reserves estimates meet the requirements regarding qualifications. Our principal internal 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. The reserves estimation is part of our internal controls process subject to management's annual review and approval. These reserves estimates are prepared by Netherland, Sewell & Associates, Inc. ("NSAI") and Ryder Scott Company ("RSC"), our independent reserve engineer consulting firms. All of our proved reserves estimates shown herein at December 31, 2018 and 2017 have been independently prepared by NSAI and RSC. NSAI prepared the estimates on all our proved reserves as of December 31, 2018 and 2017 on our properties other than in the TMS. RSC prepared the estimate of proved reserves as of December 31, 2018 and 2017 for our TMS properties. Copies of the summary reserve reports of NSAI and RSC for 2017 are filed as exhibits 99.1 and 99.2, respectively to this Annual Report on Form 10-K. All of the subject reserves are located in the continental United States, primarily in Texas, Louisiana and Mississippi.

Many assumptions and judgmental decisions are required to estimate reserves. Quantities reported are considered reasonable but are subject to future revisions, some of which may be substantial, as additional information becomes available. Such additional knowledge may be gained as the result of reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes, and other factors.

Regulations published by the SEC define proved oil and natural gas reserves 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 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.

Prices we used to value our reserves are based on the twelve-month un-weighted arithmetic average of the first-day-of-the-month price for the period January through December 2018. For oil volumes, the average price of $65.56 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For natural gas volumes, the average price of $3.10 per MMBtu is adjusted by lease for energy content, transportation fees, and regional price differentials.

Capitalized Costs

The table below reflects our capitalized costs related to our oil and natural gas producing activities at December 31, 2018 and 2017 (in thousands):

	Year Ended December 31, 2018	**Year Ended December 31, 2017**
Proved properties	$206,097	$120,333
Unproved properties	180	5,984
	206,277	126,317
Less: accumulated depreciation, depletion and amortization	(41,886)	(15,632)
Net oil and natural gas properties	$164,391	$110,685

We did not have any capitalized exploratory well costs that were pending the determination of proved reserves as of December 31, 2018 and 2017, respectively.

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Costs Incurred

Costs incurred in oil and natural gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows (in thousands):

	Year Ended December 31, 2018	**Year Ended December 31, 2017**
Property Acquisition		
Unproved	$ 178	$ 527
Proved	-	-
Exploration	-	-
Development (1)	106,583	41,148
Total (2)	$ 106,761	$ 41,675

(1) Includes asset retirement costs of less than $0.1 million in 2018 and zero in 2017.
(2) Substantially all the costs incurred related to the Haynesville Shale Trend.

The following table sets forth our net proved oil and natural gas reserves at December 31, 2018, 2017 and 2016 and the changes in net proved oil and natural gas reserves during such years, as well as proved developed and proved undeveloped reserves at the beginning and end of each year:

	Natural Gas (Mmcf)			**Oil, Condensate and NGLs (MBbls)**		
	2018	**2017**	**2016**	**2018**	**2017**	**2016**
Net proved reserves at beginning of period	415,224	286,038	31,851	2,130	2,815	3,834
Revisions of previous estimates (1)	(16,993)	106,639	(4,426)	(388)	(381)	(543)
Extensions, discoveries and improved recovery (2)	100,499	32,871	264,166	-	-	-
Purchases of minerals in place	-	-	-	-	-	-
Sales of minerals in place	(3,349)	-	2	(84)	-	-
Production	(24,444)	(10,324)	(5,555)	(217)	(304)	(476)
Net proved reserves at end of period	470,937	415,224	286,038	1,441	2,130	2,815
Net proved developed reserves:						
Beginning of period	52,861	21,872	31,851	2,130	2,815	3,834
End of period	92,118	52,861	21,872	1,441	2,130	2,815
Net proved undeveloped reserves:						
Beginning of period	362,363	264,166	-	-	-	-

End of period	378,819	362,363	264,166	-	-	-

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	Natural Gas Equivalents (Mmcfe)		
	2018	**2017**	**2016**
Net proved reserves at beginning of period	428,002	302,927	54,852
Revisions of previous estimates (1)	(19,320)	104,354	(7,683)
Extensions, discoveries and improved recovery (2)	100,499	32,871	264,166
Purchases of minerals in place	-	-	-
Sales of minerals in place (3)	(3,852)	-	2
Production	(25,746)	(12,150)	(8,410)
Net proved reserves at end of period	479,583	428,002	302,927
Net proved developed reserves:			
Beginning of period	65,639	44,432	54,852
End of period	100,764	65,639	44,432
Net proved undeveloped reserves:			
Beginning of period	362,363	258,495	-
End of period	378,819	362,363	258,495

(1) Revisions of previous estimates in 2018 and 2016 were negative, primarily due to increases in our operating expenditures and other tax rates. Revision of previous estimates in 2017 were positive due to the application of both experience and ever improving technology in drilling and completing Haynesville Shale natural gas wells. Well production performance has improved by drilling longer laterals, increasing both the number of frac stages and the amount of sand used in each frac stage.

(2) Extensions and discoveries were positive on an overall basis in all three periods presented, primarily reflecting our successful drilling results on our Haynesville Shale Trend properties.

(3) In 2018, we sold approximately 2,500 Mmcfe attributed to the sale of producing properties in the TMS and Haynesville Shale.

Standardized Measure

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves as of year-end is shown below (in thousands):

	2018	**2017**	**2016**
Future revenues	$1,494,557	$1,260,490	$595,745
Future lease operating expenses and production taxes	(410,957)	(430,048)	(213,030)
Future development costs (1)	(349,552)	(329,938)	(222,892)
Future income tax expense	(56,784)	(17,113)	(456)
Future net cash flows	677,264	483,391	159,367
10% annual discount for estimated timing of cash flows	(279,679)	(223,081)	(102,445)
Standardized measure of discounted future net cash flows	$397,585	$260,310	$56,922
Index price used to calculate reserves (2)			

Natural gas (per Mcf)	$3.10	$2.98	$2.48
Oil (per Bbl)	$65.56	$51.34	$42.75

(1) Includes cumulative asset retirement obligations of $7.3 million and $7.2 million in 2018 and 2017, respectively.
(2) These index prices, used to estimate our reserves at these dates, are before deducting or adding applicable transportation and quality differentials on a well-by-well basis.

The estimated future net cash flows are discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. The standardized measure of discounted cash flows is the future net cash flows less the computed discount.

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Changes in the Standardized Measure

The following are the principal sources of change in the standardized measure of discounted net cash flows for the years shown (in thousands):

	Year Ended December 31,		
	2018	**2017**	**2016**
Balance, beginning of year	$260,310	$56,922	$69,895
Net changes in prices and production costs related to future production	95,927	113,319	(20,442)
Sales and transfers of oil and natural gas produced, net of production costs	(63,846)	(32,012)	(15,826)
Net change due to revisions in quantity estimates	(25,595)	107,499	(8,630)
Net change due to extensions, discoveries and improved recovery	129,207	8,970	25,638
Net change due to purchases and sales of minerals in place	(3,382)	-	648
Changes in future development costs	(4,608)	(59,560)	2,102
Previously estimated development cost incurred in period	7,923	8,114	-
Net change in income taxes	(16,336)	(3,686)	(164)
Accretion of discount	26,416	5,709	6,990
Change in production rates (timing) and other	(8,431)	55,035	(3,289)
Net increase (decrease) in standardized measures	137,275	203,388	(12,973)
Balance, end of year	$397,585	$260,310	$56,922

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Item 9.*Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A.*Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission and that any material information relating to us is recorded, processed, summarized and reported to our management including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by SEC rule 13a-15(b), we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(c) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our Chief Executive Officer and Chief Financial Officer, based upon their evaluation as of December 31, 2018, the end of the period covered in this report, concluded that our disclosure controls and procedures were effective.

Management's Annual Report on Internal Control Over Financial Reporting

See Item 8—Financial Statements and Supplementary Data—Management's Annual Report on Internal Controls over Financial Reporting" of this Annual Report on Form 10-K.

Attestation Report of the Registered Public Accounting Firm

See “Item 8— Financial Statements and Supplementary Data—Report of Independent Registered Public Accounting Firm” of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

Item 9B. ***Other Information***

None.

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PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

Our executive officers and directors and their ages and positions as of March 5, 2019, are as follows:

Name	Age	Position
Walter G. "Gil" Goodrich	60	Chairman of the Board of Directors, Chief Executive Officer and Director
Robert C. Turnham, Jr.	61	President, Chief Operating Officer and Director
Mark E. Ferchau	64	Executive Vice President
Michael J. Killelea	56	Executive Vice President, General Counsel and Corporate Secretary
Robert T. Barker	68	Senior Vice President, Controller, Chief Accounting Officer and Chief Financial Officer
Ronald F. Coleman	64	Director
Steven J. Pully	59	Director
K. Adam Leight	62	Director
Timothy D. Leuliette	69	Director
Thomas M. Souers	65	Director

Walter G. "Gil" Goodrich became Chairman of the Board in 2015 and served as Vice Chairman of our Board since 2003. He has served as our Chief Executive Officer since 1995. Mr. Goodrich was Goodrich Oil Company's Vice President of Exploration from 1985 to 1989 and its President from 1989 to 1995. He joined Goodrich Oil Company, which held interests in and served as operator of various properties owned by a predecessor of the Company, as an exploration geologist in 1980. He has served as a director since 1995.

Robert C. Turnham, Jr. has served as our Chief Operating Officer since 1995. He became President and Chief Operating Officer in 2003. He has held various positions in the oil and natural gas business since 1981. From 1981 to 1984, Mr. Turnham served as a financial analyst for Pennzoil. In 1984, he formed Turnham Interests, Inc. to pursue oil and natural gas investment opportunities. From 1993 to 1995, he was a partner in and served as President of Liberty Production Company, an oil and natural gas exploration and production company. He has served as a director since 2006.

Mark E. Ferchau became Executive Vice President of the Company in 2004. He had previously served as the Company's Senior Vice President, Engineering and Operations, after initially joining the Company as a Vice President in 2001. Mr. Ferchau previously served as Production Manager for Forcenergy Inc. from 1997 to 2001 and as Vice President, Engineering of Convest Energy Corporation from 1993 to 1997. Prior thereto, Mr. Ferchau held various positions with Wagner & Brown, Ltd. and other independent oil and gas companies.

Michael J. Killelea joined the Company as Senior Vice President, General Counsel and Corporate Secretary in 2009. He was named Executive Vice President in December 2016. Mr. Killelea has over 30 years of experience in the energy industry. In 2008, he served as interim-Vice President, General Counsel and Corporate Secretary for Maxus Energy Corporation. Prior to that time, Mr. Killelea was Senior Vice President, General Counsel and Corporate Secretary of Pogo Producing Company from 2000 through 2007. Mr. Killelea held various positions within the law department at CMS Energy Corporation from 1988 to 2000, including Chief Counsel at CMS Oil & Gas Company from 1995 to 2000.

Robert T. Barker joined the Company in 2007 as Manager, Financial Reporting and has held various positions within the Accounting Department with increasing responsibility, most recently as Vice President, Controller and Chief Financial Officer. In January 2018, he was named Senior Vice President. Mr. Barker has over 30 years of experience in the energy industry. Prior to joining the Company, Mr. Barker was Controller for Cygnus Oil and Gas Corporation. Mr. Barker is a Certified Public Accountant and holds an MBA from the University of Houston.

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Ronald F. Coleman is an energy executive with over 37 years of international and domestic oilfield services operations. From 2012 to 2014, Mr. Coleman was president North America and executive vice president of Archer. Prior to that, Mr. Coleman served as chief operating officer and executive vice president of Select Energy Services in 2011. Mr. Coleman spent 33 years at BJ Services Company, serving as vice president of operations in U.S. and Mexico from 1998 to 2007 and Vice President North America Pumping from 2007 to 2010. He has served on numerous boards, including Torqued Up Energy Services, Titan Liner (CWCS Company), Solaris Oil Field Services, and Ranger Energy Services. He has also been appointed by boards to serve in advising roles for CSL Energy Opportunities Fund II, LP, and Matador Resources Company. He was appointed to the Company's Board of Directors in 2016.

Steven J. Pully provides consulting and investment banking services for companies and investors focused on the oil and gas sector. From 2008 until 2014, Mr. Pully served as General Counsel and a Partner of the investment firm Carlson Capital, L.P. Mr. Pully was also previously a Senior Managing Director at Bear Stearns and a Managing Director at Bank of America Securities focused on energy investment banking. Mr. Pully is on three other public company boards, Bellatrix Exploration, Harvest Oil and Gas and VAALCO Energy and has also served on numerous other boards of public and private companies in the oil and gas and other industries, including as a director of EPL Oil & Gas and Energy XXI within the past five years. Mr. Pully is a Chartered Financial Analyst, a Certified Public Accountant in the State of Texas and a member of the State Bar of Texas. Mr. Pully earned his undergraduate degree in Accounting from Georgetown University and is also a graduate of The University of Texas School of Law. He was appointed to the Company's Board in March 2017.

K. Adam Leight has spent over 35 years building and managing investment research departments, covering the energy industry for major financial institutions, and advising investors and managements. Mr. Leight is presently a managing member of Ansonia Advisors LLC, which provides independent research, capital markets, and corporate advisory services to various institutions and to the energy industry. He is also a Senior Advisor with Al Petrie Advisors, providing capital markets and investor relations advice to energy industry managements. Previously, Mr. Leight served as a managing director at RBC Capital Markets from 2008 to 2016, managing director at Credit Suisse from 2000 to 2007 and managing director at Donaldson, Lufkin & Jenrette from 1994 to 2000. Before that, Mr. Leight was managing director at Cowen & Company, vice president at Drexel Burnham Lambert, and an analyst at Sutro & Co. He currently serves on the board of Warren Resources, an independent oil and gas production company. Mr. Leight has also served on the advisory boards of Falcon Capital Management, University of Wisconsin ASAP, and various non-profit boards. Mr. Leight holds an A.B. in economics from Washington University, an M.S. in investment finance from the University of Wisconsin and is a Chartered Financial Analyst. He was appointed to the Company's Board of Directors in 2016.

Timothy D. Leuliette served as the president, chief executive officer and a member of the board of directors of Visteon Corporation from September 2012 to June 2015. Upon assuming his role at Visteon, Mr. Leuliette left FINNEA Group, a firm he had co-founded and where he was a senior managing director. He left the FINNEA Group's predecessor firm to serve as chairman, president and chief executive officer of Dura Automotive LLC, for two years to oversee its emergence from bankruptcy, it's financial and operational restructuring and its successful sale. Prior to that, Mr. Leuliette was co-chief executive officer of Asahi Tec Corporation and chairman and chief executive officer of its subsidiary Metaldyne Corporation, a company he co-founded in 2000. Mr. Leuliette was formerly president and chief operating officer of Penske Corporation, president and chief executive officer of ITT Automotive Group and senior vice president of ITT Industries Inc. Before joining ITT, Mr. Leuliette served as president and chief executive officer of Siemens Automotive L.P and was a member of the Siemens Automotive managing board and a corporate vice president of Siemens AG. Mr. Leuliette has also served on numerous boards and recent directorships, including Visteon Corporation, Business Leaders of Michigan, and The Detroit Economic Club. He is a past chairman of the board of The Detroit Branch of The Federal Reserve Bank of Chicago. Mr. Leuliette holds a B.S. in mechanical engineering and a Master's Degree in business administration from the University of Michigan. He was appointed to the Company's Board of Directors in 2016.

Thomas M. Souers served as petroleum engineering consultant at Netherland, Sewell & Associates, Inc. (NSAI) from 1991 until his retirement in 2016. During that time, Mr. Souers worked on a range of oil and gas reserves estimations, property evaluations for sales and acquisitions, analysis of secondary recovery projects, field studies, deliverability studies, prospect evaluations, and economic evaluations utilizing deterministic methodology for projects in North America, Europe, Africa, South America, and Asia. His areas of expertise are Gulf of Mexico and horizontal drilling in various US basins. Mr. Souers has also served as expert witness on a number of civil cases. Mr. Souers also served as a consulting COO of a private oil and gas company during his employment at NSAI. Prior to that time, Mr. Souers served as an operations engineer with GLG Energy LP, senior staff engineer with Wacker Oil Inc., area manager with Transco Exploration Company, and supervising engineer with Exxon Company, U.S.A. Mr. Souers holds a B.S. in civil engineering from North Carolina State University and an M.S. in civil engineering from the University of Florida. He was appointed to the Company's Board of Directors in 2016.

Additional information required under this "Item 10—Directors, Executive Officers and Corporate Governance," will be provided in our Proxy Statement for the 2018 Annual Meeting of Stockholders. The information required by this Item is incorporated by reference to the information provided in our definitive proxy statement for the 2019 annual meeting of stockholders to be filed within 120 days from December 31, 2018. Additional information regarding our corporate governance guidelines as well as the complete text of our Code of Business Conduct and Ethics and the charters of our Audit Committee, Compensation Committee and our Nominating and Corporate Governance Committee may be found on our website at *www.goodrichpetroleum.com.*

Item 11. *Executive Compensation*

The information required by this Item is incorporated by reference to the information provided under the caption "Executive Compensation" in our definitive proxy statement for the 2018 Annual Meeting of Stockholders to be filed within 120 days from December 31, 2018.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information required by this Item is incorporated by reference to the information provided under the caption "Security Ownership of Certain Beneficial Owners and Management" in our definitive proxy statement for the 2018 Annual Meeting of Stockholders to be filed within 120 days from December 31, 2018.

Item 13. *Certain Relationships and Related Transactions and Director Independence*

The information required by this Item is incorporated by reference to the information provided under the caption “Transactions with Related Persons” and “Corporate Governance-Our Board-Board Size; Director Independence” in our definitive proxy statement for the 2018 Annual Meeting of Stockholders to be filed within 120 days from December 31, 2018.

Item 14. ***Principal Accounting Fees and Services***

The information required by this Item is incorporated by reference to the information provided under the caption “Audit and Non-Audit Fees” in our definitive proxy statement for the 2018 Annual Meeting of Stockholders to be filed within 120 days from December 31, 2018.

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PART IV

Item 15.*Exhibits, Financial Statement Schedules*

(a)(1) and (2) Financial Statements and Financial Statement Schedules

See "Index to Consolidated Financial Statements" on page 56.

All schedules are omitted because they are not applicable, not required or the information is included within the consolidated financial information or related notes.

(a)(3) Exhibits

2.1	Purchase and Sale Agreement between Goodrich Petroleum Corporation and EP Energy E&P Company, L.P., dated as of July 24, 2015 (Incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-12719) filed on July 30, 2015).
2.2	First Amended Joint Chapter 11 Plan of Reorganization of Goodrich Petroleum Corporation and its subsidiary, Goodrich Petroleum Company L.L.C., dated August 12, 2016 (Incorporated by reference to Exhibit 2.1 of the Company's Form 8-K (File No. 001-12719) filed on October 3, 2016).
3.1	Second Amended and Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated October 12, 2016, (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-8 (File No. 333-214080) filed on October 12, 2016).
3.2	Second Amended and Restated Bylaws of Goodrich Petroleum Corporation, dated October 12, 2016, (Incorporated by reference to Exhibit 4.2 of the Company's Registration Statement on Form S-8 (File No. 333-214080) filed on October 12, 2016).
4.1	Specimen Common Stock Certificate (Incorporated by reference to Exhibit 4.6 of the Company's Registration Statement on Form S-8 (File No. 33-01077) filed February 20, 1996).
4.2	Indenture, dated as of October 12, 2016, by and between Goodrich Petroleum Corporation, Goodrich Petroleum Company, L.L.C., as the Subsidiary Guarantor, and Wilmington Trust, National Association, as trustee and collateral agent, relating to the 13.50% Convertible Second Lien Senior Secured Notes due 2019 (Incorporated by reference to Exhibit 4.1 of the Company's Form 8-K (File No. 001-12719) filed on October 14, 2016).
10.1	Credit Agreement, dated as of October 17, 2017, among Goodrich Petroleum Corporation, as Parent Guarantor, Goodrich Petroleum Company, L.L.C., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-12719) filed on October 19, 2017).
10.2	

	Restructuring Support Agreement and term sheet, dated March 28, 2016 (Incorporated by reference to Exhibit 10.1 of the Company's Form 8-K (File No. 001-12719) filed on April 1, 2016).
10.3	Note Purchase Agreement, dated as of October 12, 2016, by and among Goodrich Petroleum Corporation, Goodrich Petroleum Company, L.L.C., as subsidiary guarantor and the Purchasers named therein (Incorporated by reference to Exhibit 10.2 of the Company's Form 8-K (File No. 001-12719) filed on October 14, 2016).

10.4	Registration Rights Agreement, dated as of October 12, 2016, by and among Goodrich Petroleum Corporation and the Holders party thereto, relating to the Convertible Second Lien Notes. (Incorporated by reference to Exhibit 10.3 of the Company's Form 8-K (File No. 001-12719) filed on October 14, 2016).
10.5	Warrant Agreement, dated as of October 12, 2016, by and between Goodrich Petroleum Corporation and American Stock Transfer & Trust Company, LLC, relating to the 2L Fee Warrants (Incorporated by reference to Exhibit 10.4 of the Company's Form 8-K (File No. 001-12719) filed on October 14, 2016).
10.6	Registration Rights Agreement, dated as of October 12, 2016, by and among Goodrich Petroleum Corporation and the Holders party thereto, relating to the 2L Fee Warrants (Incorporated by reference to Exhibit 10.5 of the Company's Form 8-K (File No. 001-12719) filed on October 14, 2016).
10.7	Warrant Agreement, dated as of October 12, 2016, by and between Goodrich Petroleum Corporation and American Stock Transfer & Trust Company, LLC, relating to the UCC Warrants (Incorporated by reference to Exhibit 10.6 of the Company's Form 8-K (File No. 001-12719) filed on October 14, 2016).
10.8	Registration Rights Agreement, dated as of October 12, 2016, by and among Goodrich Petroleum Corporation and the Holders party thereto (Incorporated by reference to Exhibit 10.7 of the Company's Form 8-K (File No. 001-12719) filed on October 14, 2016).
10.9	Common Stock Subscription Agreement, dated as of December 19, 2016, by and among the Company and the Purchasers named therein (Incorporated by reference to Exhibit 10.1 of the Company's Form 8-K (File No. 001-12719) filed on December 22, 2016).
10.10	Registration Rights Agreement, dated as of December 22, 2016, by and among the Company and the Purchasers named therein (Incorporated by reference to Exhibit 10.2 of the Company's Form 8-K (File No. 001-12719) filed on December 22, 2016).
10.11†	Goodrich Petroleum Corporation Management Incentive Plan. (Incorporated by reference to Exhibit 4.3 of the Company's Registration Statement on Form S-8 (File No. 333-214080) filed on October 12, 2016).
10.12†	First Amendment to the Goodrich Petroleum Corporation Management Incentive Plan effective December 8, 2016 (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on August 4, 2017).
10.13†	Second Amendment to the Goodrich Petroleum Corporation Management Incentive Plan effective May 23, 2017 (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on August 4, 2017).
10.14†	Form of Grant of Restricted Stock. (Incorporated by reference to Exhibit 4.4 of the Company's Registration Statement on Form S-8 (File No. 333-214080) filed on October 12, 2016) (attached as Exhibit A to the 2016 Long Term Incentive Plan).
10.15†	Form of Grant of Restricted Stock (Secondary Exit Award; UCC Warrant Exercise). (Incorporated by reference to Exhibit 4.5 of the Company's Registration Statement on Form S-8 (File No. 333-214080) filed on October 12, 2016).
10.16†	Form of Grant of Restricted Stock (Secondary Exit Award; 2L Note Conversion). (Incorporated by reference to Exhibit 4.6 of the Company's Registration Statement on Form S-8 (File No. 333-214080) filed on October 12, 2016).
10.17†	Amended and Restated Severance Agreement between the Company and Walter G. Goodrich dated November 5, 2007 (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on November 8, 2007).
10.18†	First Amendment to the Amended and Restated Severance Agreement dated October 11, 2016 between Goodrich Petroleum Corporation and Walter G. Goodrich. (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on November 9, 2016).
10.19†	Amended and Restated Severance Agreement between the Company and Robert C. Turnham, Jr. dated November 5, 2007 (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on November 8, 2007).

10.20†	First Amendment to the Amended and Restated Severance Agreement dated October 11, 2016 between Goodrich Petroleum Corporation and Robert C. Turnham, Jr. (Incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on November 9, 2016).
10.21†	Amended and Restated Severance Agreement between the Company and Mark E. Ferchau dated November 5, 2007 (Incorporated by reference to Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on November 8, 2007).
10.22†	First Amendment to the Amended and Restated Severance Agreement dated October 11, 2016 between Goodrich Petroleum Corporation and Mark E. Ferchau. (Incorporated by reference to Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on November 9, 2016).
21	Subsidiary of the Registrant:
	Goodrich Petroleum Company L.L.C. - Organized in the State of Louisiana.
23.1*	Consent of Moss Adams LLP-Independent Registered Public Accounting Firm.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Ryder Scott Company.
31.1*	Certification by Chief Executive Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification by Chief Financial Officer Pursuant to 15 U.S.C. Section 7241, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification by Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification by Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
99.2*	Report of Ryder Scott Company, Independent Petroleum Engineers and Geologists.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

* Filed herewith.
** Furnished herewith.
† Denotes management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 5, 2019.

GOODRICH PETROLEUM CORPORATION

By: /s/ WALTER G. GOODRICH
Walter G. Goodrich

Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below hereby constitutes and appoints Walter G. Goodrich and Robert T. Barker and each of them, his true and lawful attorney-in-fact and agent, with full powers of substitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission granting to said attorneys-in-fact, and each of them, full power and authority to perform any other act on behalf of the undersigned required to be done in connection therewith.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant in the capacities indicated on March 5, 2019.

Signature	Title
/s/ WALTER G. GOODRICH **Walter G. Goodrich**	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ ROBERT C. TURNHAM, JR.	President, Chief Operating Officer and Director

Robert C. Turnham, Jr.

/s/ ROBERT T. BARKER **Robert T. Barker**	Senior Vice President, Controller, Chief Accounting Officer and Chief Financial Officer
/s/ RONALD COLEMAN **Ronald Coleman**	Director
/s/ ADAM LEIGHT **Adam Leight**	Director
/s/ TIM LEULIETTE **Tim Leuliette**	Director
/s/ STEVEN J. PULLY **Steven J. Pully**	Director
/s/ TOM SOUERS **Tom Souers**	Director