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, 2019

OR

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

Commission file number: 001-12719

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

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

(Registrant's telephone number, including area code) (713) 780-9494

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

Common Stock, par value $0.01 per share	GDP	NYSE American
(Title of Each Class)	***(Trading Symbol)***	***(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 every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

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, 2019, the last business day of the Registrant's most recently completed second fiscal quarter) was approximately $67.9 million. The number of shares of the Registrant's common stock par value $0.01 per share, outstanding as of March 2, 2020 was 12,532,950.

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.

GOODRICH PETROLEUM CORPORATION

**ANNUAL REPORT ON FORM 10-K
FOR THE FISCAL YEAR ENDED
December 31, 2019**

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 176 producing oil and natural gas wells located in 37 fields in seven states. At December 31, 2019, we had estimated proved reserves of approximately 517 Bcfe, comprised of 510 Bcf of natural gas and 1.1 MMBbls of oil and condensate.

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

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.

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 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) of Regulation S-X.

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

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

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

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

Proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. As used in this definition, “existing economic conditions” include prices and costs at which economic producibility from a reservoir is to be determined. The prices shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. The SEC provides a complete definition of proved reserves in Rule 4-10 (a) (22) of Regulation S-X.

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

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.

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

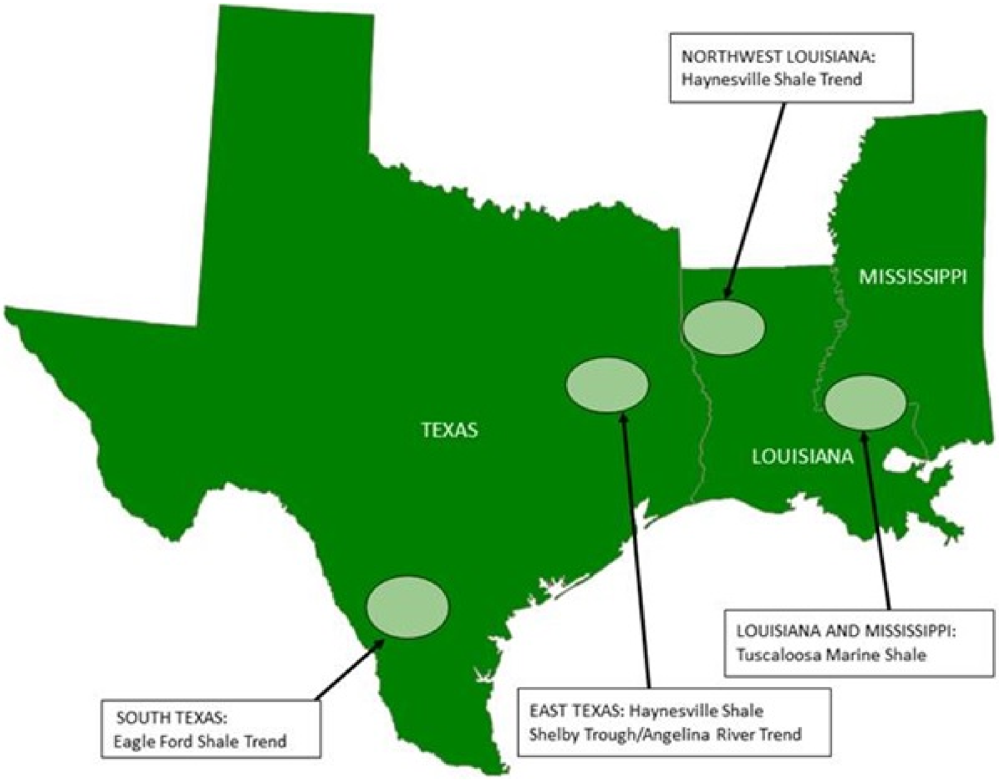
Working interest is the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover is a series of operations on a producing well to restore or increase production.

Oil and Natural Gas Operations and Properties

As of December 31, 2019, nearly all of our proved oil and natural gas reserves were located in Louisiana, Texas and Mississippi. We spent substantially all of our 2019 capital expenditures of $98.4 million in the Haynesville Shale Trend of Northwest Louisiana. Our total capital expenditures, including accrued costs for services performed during 2019, consisted of $97.9 million for drilling and completion costs, $0.3 million for asset retirement obligations, and $0.2 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 2020 capital expenditure budget is planned for Haynesville Shale Trend development.



The table below details our acreage positions, average working interest and producing wells as of December 31, 2019:

Field or Area	**Acreage As of December 31, 2019 Gross**	**Acreage As of December 31, 2019 Net**	**Average Producing Well Working Interest**	**Producing wells at December 31, 2019**
Tuscaloosa Marine Shale Trend	47,786	33,192	65%	36
Haynesville Shale Trend	39,767	21,696	39%	116
Eagle Ford Shale Trend	18,909	12,445	-	-
Other	33,125	7,323	9%	24

Haynesville Shale Trend

As of December 31, 2019, we have acquired or farmed-in leases totaling approximately 40,000 gross (22,000 net) acres in the Haynesville Shale Trend. During 2019, we added 9 gross (7.2 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, 2019, we had 7 gross (3.2 net) wells in the drilling or completion phase in the Haynesville Shale Trend.

Tuscaloosa Marine Shale Trend

As of December 31, 2019, we own approximately 48,000 gross (33,000 net) lease acres in the TMS, an oil shale play in Southwest Mississippi and Southeast Louisiana. Approximately 47,000 gross (33,000 net) acres are currently held by production. During 2019, we did not conduct any drilling operations and did not add any wells to production. As of December 31, 2019, we had 2 gross (1.7 net) wells waiting on completion operations in the TMS.

Eagle Ford Shale Trend

As of December 31, 2019, we have retained approximately 12,000 net acres of undeveloped leasehold in the Eagle Ford Shale Trend in Frio County, Texas.

Other

As of December 31, 2019, 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, 2019 and 2018, 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, 2019 on properties other than those located in the TMS. RSC prepared the estimate of proved reserves as of December 31, 2019 for our TMS properties. Copies of the summary reserve reports of NSAI and RSC as of December 31, 2019 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, 2019 below were calculated using flat, twelve month average commodity index prices of $55.69 per barrel and $2.58 per MMBtu.

	Proved Reserves at December 31, 2019			
	Developed Producing	Developed Non-Producing	Undeveloped	Total
	(dollars in thousands)			
Net Proved Reserves:				
Oil (MBbls) (1)	1,104	-	-	1,104
Natural Gas (Mmcf)	137,683	924	371,459	510,066
Mcf Natural Gas Equivalent (Mmcfe) (2)	144,308	924	371,459	516,691
Estimated Future Net Cash Flows				$ 556,536
PV-10 (3)				$ 296,954
Discounted Future Income Taxes				(2,631)
Standardized Measure of Discounted Net Cash Flows (3)				$ 294,323

	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

(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, 2019			
Area	Proved Developed	Proved Undeveloped	Proved Reserves	% of Total
Tuscaloosa Marine Shale Trend	6,549	-	6,549	1%
Haynesville Shale Trend	138,554	371,459	510,013	99%
Other	129	-	129	0%
Total	145,232	371,459	516,691	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 2019 through December 2019, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For reserves at December 31, 2019, the average twelve month prices used were $2.58 per MMBtu of natural gas and $55.69 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, 2019 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 35 years of experience in the oil and natural gas industry, including over 30 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 a participant in professional industry groups and has been a member of the Society of Petroleum Engineers for over 35 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, 2019, as estimated by NSAI and RSC, were 517 Bcfe, consisting of 510 Bcf of natural gas and 1.1 MMBbls of oil and condensate. In 2019, we added approximately 218 Bcfe related to our drilling activities in the Haynesville Shale Trend. We had negative revisions of approximately 133 Bcfe due primarily to natural gas prices and produced 48 Bcfe in 2019. We continue to employ completion techniques on our Haynesville Shale Trend wells which have been proven successful by the production volume results from the wells we drilled in 2019 and 2018. 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, 2019.

Our proved undeveloped (“PUD”) reserves at December 31, 2019, all in our Haynesville Shale Trend, were 371 Bcfe, or 72% of our total proved reserves. In 2019, we had new additions of 182 Bcfe reflective of our plans to developed theses reserves in and after the year 2022 but before five years have elapsed. We had net negative revisions of previous estimates of 139 Bcfe. We developed approximately 50 Bcfe, or 13% of our total proved undeveloped reserves booked as of December 31, 2018, through the drilling of 4 gross (3.9 net) development wells. Of the proved undeveloped reserves in our December 31, 2019 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 net negative PUD revision of previous estimates was primarily attributable to recognizing that reserves under current natural gas pricing representing approximately 147 Bcfe would not be developed within five years since they were originally booked. In addition, we had ownership decreases of 4 Bcfe and an increase of 12 Bcfe mostly due to economic parameter adjustments such as improved well performance.

Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2019:

	Oil		Natural Gas		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Tuscaloosa Marine Shale Trend:						
Southeast Louisiana	13	9.2	-	-	13	9.2
Southwest Mississippi	23	14.3	-	-	23	14.3
Haynesville Shale Trend:						
East Texas	-	-	3	0.9	3	0.9
Northwest Louisiana	-	-	111	42.9	111	42.9
Other	6	0.3	20	2.7	26	3.0
Total Productive Wells	42	23.8	134	46.5	176	70.3

(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, 2019. 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	29,191	20,372	76	1	29,267	20,373
Southeast Louisiana	18,205	12,536	313	284	18,518	12,820
Haynesville Shale Trend:						
East Texas	33,367	9,074	4,938	909	38,305	9,983
Northwest Louisiana	31,596	18,040	880	792	32,476	18,832
Eagle Ford Shale Trend:						
South Texas	5,525	3,951	13,384	8,493	18,909	12,444
Other	2,103	195	9	9	2,112	204
Total	119,987	64,168	19,600	10,488	139,587	74,656

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

Lease Expirations

We have undeveloped lease acreage primarily in the Eagle Ford Shale Trend that will expire during the next two 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, 2019:

Year	Net Acreage
2020	8,610
2021	56

Operator Activities

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

Drilling Activities

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

	Year Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	9	7.2	16	7.5	5	1.5
Non-Productive	-	-	-	-	-	-
Total	9	7.2	16	7.5	5	1.5
Exploratory Wells:						
Productive	-	-	-	-	-	-
Non-Productive	-	-	-	-	-	-
Total	-	-	-	-	-	-
Total Wells:						
Productive	9	7.2	16	7.5	5	1.5
Non-Productive	-	-	-	-	-	-
Total	9	7.2	16	7.5	5	1.5

At December 31, 2019, we had 9 gross (4.9 net) development wells waiting to be completed.

Net Production, Unit Prices and Costs

The following table presents certain information with respect to oil and natural gas production attributable to our interests in all of our properties (including two fields which have attributed more than 15% of our total proved reserves as of December 31, 2019), 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, 2019.

	Sales Volumes			Average Sales Prices (1)				
	Natural Gas Mmcf	Oil & Condensate MBbls	Total Mmcfe	Natural Gas Mmcf	Oil & Condensate MBbls	Total Mmcfe	% of Total Revenue	Average Production Cost (2) Per Mcfe
For Year 2019:								
TMS	-	169	1,011	$ -	$ 60.92	$ 10.15	9%	$ 5.30
Haynesville Shale Trend	46,436	-	46,436	2.31	-	2.31	90%	0.14
Other	275	2	290	3.12	50.28	3.38	1%	1.04
Total	46,711	171	47,737	$ 2.31	$ 60.77	$ 2.48	100%	$ 0.26
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

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.

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, 2019 and 2018 are as follows:

	Year Ended December 31,	
	2019	2018
CIMA Energy, LP	39%	41%
Shell	19%	0%
ETC	19%	15%
CES	10%	8%
Genesis Crude Oil LP	8%	13%

Competition

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

Seasonality of Business

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

Employees

At February 28, 2020 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.

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. 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 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, and the WOTUS rule was rescinded in September 2019. On January 23, 2020, the EPA and the Corps finalized the Navigable Waters Protection Rule, which narrows jurisdiction under the CWA relative to the WOTUS rule. However, legal challenges to the new rule are expected, and multiple challenges to the EPA's prior rulemakings remain pending. 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, imposes a variety of requirements related to the prevention of oil spills into navigable waters as well as liabilities for oil cleanup costs, natural resource damages and a variety of public and private damages that may result from such oil spills.

The disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended ("SDWA"), and analogous state laws. The SDWA's Underground Injection Control Program establishes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities as well as a prohibition against the migration of fluid containing any contaminants into underground sources of drinking water. State programs may have analogous permitting and operational requirements. In response to concerns related to increased seismic activity in the vicinity of injection wells, regulators in some states are considering additional requirements related to seismic safety. For example, the Texas Railroad Commission ("RRC") has previously adopted oil and gas permit rules in 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.

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

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that greenhouse gas ("GHG") emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, implement New Source Performance Standard ("NSPS") OOOOa directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. In August 2019, EPA proposed amendments to NSPS OOOOa that would remove methane specific requirements from the oil and natural gas source category, while keeping in place requirements for volatile organic compounds. Legal challenges to any final rulemaking that rescinds NSPS OOOOa is expected. Similarly, the Bureau of Land Management has adopted certain regulations relating to GHG emissions from operations on federal and tribal land, and certain rescissions are pending legal challenge. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is an agreement, the United Nations-sponsored "Paris Agreement," for nations to limit their GHG emissions through non-binding, individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Two critical declarations made by one or more candidates running for the Democratic nomination for President include threats to take actions banning hydraulic fracturing of oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as the reversal of the United States' withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

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.

Endangered Species

The Federal Endangered Species Act, as amended ("ESA"), and analogous state laws restrict activities that could have an adverse effect on threatened or endangered species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. Moreover, as a result of a court settlement, the U.S. Fish and Wildlife Service ("USFWS") was required to make a determination on listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. The USFWS did not complete the review by the deadline and continues to review species for protected status under the ESA. The presence of protected species or the designation of previously unidentified endangered or threatened species could impair our ability to timely complete well drilling and development and could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee Health and Safety

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

Other Laws and Regulations

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

Item 1A. ***Risk Factors***

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

The Company has made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with Company management, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended concerning the Company's operations, economic performance and financial condition. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and natural gas properties, marketing and midstream activities, and also include those statements accompanied by or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "predicts," "target," "goal," "plans," "objective," "potential," "should," or similar expressions or 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 risks 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 and production from our wells;*
- *the creditworthiness of our hedging counterparties and the effect of our 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 operating partners; and*
- *other factors discussed below and elsewhere in this Annual Report on Form 10-K and in our other public filings, press releases and discussions with our management.*

Oil and natural gas prices are volatile. A sustained decrease in the price of oil or natural gas would adversely impact our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial 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, 2015 to December 31, 2019, 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, and in the first quarter of 2020, the NYMEX Henry Hub price for natural gas has neared the five-year low. The market for these products will likely continue to be volatile in the future. Our revenues, operating results, profitability and future growth are highly dependent on the prices we receive for our production, and the levels of our production depend on numerous factors beyond our control. These factors include the following:

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

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

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

Drilling and exploration are the main methods we utilize to replace our reserves. However, drilling and exploration operations may not 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 2019 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 2019 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. In addition, 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, and expenditures we are required to pay or reimburse may be incurred at times we cannot control. If we cannot fund such capital expenditures, our interests in some properties may be reduced or forfeited.

If we are unable to or do not otherwise 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, 2019, 72% 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 lower 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.

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 2019. The prices we receive for our production may be lower than those upon which our reserve estimates are based. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

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

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

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

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

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

In addition, the 10% discount factor, which is required by the SEC to be used to calculate discounted future net cash flows for reporting purposes, and which we use in calculating our PV-10, may 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 $11.1 million for the year ended December 31, 2019 and $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 accumulated earnings of $2.7 million at December 31, 2019. 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 in an effort 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 $9.6 million during 2019 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.*

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, 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.

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.

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 whether an impairment exists. 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. We had no impairment for the years ended December 31, 2019 and 2018.

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, 2019 were associated with our Louisiana, Texas and Mississippi properties which include the Haynesville Shale Trend and, to a lesser extent, the 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, 2019, approximately 10% of our reserves and approximately 14% of our sales volumes were attributable to non-operated properties. We have less ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them versus those fields in which we are the operator. Although we have the ability to propose operations to the operator, our dependence on the operator and other working interest owners for these projects and our reduced influence or ability to control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital and lead to unexpected future costs.

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

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

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

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

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

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

Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. Revenues from the largest of these sources as a percent of oil and natural gas revenues for the years ended December 31, 2019 and 2018 were 39% and 41%, 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 establish 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, 2019 and 2018 are as follows:

	Year Ended December 31,	
	2019	**2018**
CIMA Energy, LP	39%	41%
Shell	19%	0%
ETC	19%	15%
CES	10%	8%
Genesis Crude Oil LP	8%	13%

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.

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.

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 2019 Senior Credit Facility and New 2L 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 New 2L Notes (as defined below) and our 2019 Senior Credit Facility (as defined below), contain various affirmative and negative covenants with which we must comply. For example, under the 2019 Senior Credit Facility, we are required to maintain certain financial covenants including the maintenance of (i) a ratio of Net Funded Debt (as defined in the 2019 Senior Credit Facility) to EBITDAX not to exceed 4.00 to 1.00 as of the last day of any fiscal quarter and (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 New 2L Notes remain outstanding, a ratio of Total Proved PV-10 attributable to the Company's and Subsidiary's Proved Reserves (as defined in the 2019 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.

The 2019 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 2019 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 2019 Senior Credit Facility, then we would no longer be permitted to borrow under that facility and 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, 2020, we have outstanding (i) 1.0 million warrants exercisable into approximately 1.3 million shares of the Company's common stock at an exercise price of $17.48 per share, (ii) New 2L Notes convertible into approximately 0.7 million shares of the Company's common stock at an exercise price of $21.33, and (iii) approximately 1.0 million restricted stock awards at target, collectively representing in total approximately 20% 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.

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.

Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce demand for our products.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our oil and natural gas exploration and production customers are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, implement New Source Performance Standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the Department of Transportation, implement GHG emissions limits on vehicles manufactured for operation in the United States. Similarly, the Bureau of Land Management has adopted certain regulations relating to GHG emissions from operations on federal and tribal land. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is an agreement, the United Nations-sponsored “Paris Agreement,” for nations to limit their GHG emissions through non-binding, individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Two critical declarations made by one or more candidates running for the Democratic nomination for President include threats to take actions banning hydraulic fracturing of oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as the reversal of the United States’ withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-energy related sectors. Institutional lenders who provide financing to fossil fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation.

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.

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.

The ownership position of our larger stockholders may limit other stockholders' ability to influence corporate matters and could affect the price of our common stock.

As of February 6, 2020, our largest three stockholders collectively beneficially own approximately 46% of our outstanding common stock. As a result, these stockholders will be able to exercise significant influence over matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of these stockholders with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders. Moreover, the concentration of stock ownership may adversely affect the trading price of our common stock as a result of lower public float or if investors perceive a disadvantage in owning stock of a company with a significant concentration of ownership.

We do not currently pay a dividend.

We do not currently pay cash dividends or other distributions with respect to our common stock. 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 Third Amended and Restated Certificate of Incorporation ("Charter") and our Second Amended and Restated Bylaws ("Bylaws") may have the effect of delaying or preventing changes in control if our board of directors ("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:

- 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.

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.

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

The Company's common stock trades on the NYSE American under the symbol "GDP".

At March 2, 2020, the number of holders of record of our common stock was 87 and 12,532,950 shares were outstanding.

Dividends

We do not currently pay any dividends on our common stock.

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, 2019.

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 *"Part I, 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 (the "Board") 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. The prices we receive for our production are largely beyond our control, and in the first quarter of 2020, the NYMEX Henry Hub price for natural gas has neared the five-year low. 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 more limited. See *"Item 1A—Risk Factors"* for a discussion of the risks to our business as a result of lower commodity prices.

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 volumes and reduce our per unit operating expenses.

Expand acreage position in the Haynesville Shale Trend. As of December 31, 2019, we held approximately 22,000 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, 2019, we had $1.5 million in cash and $92.9 million of outstanding borrowings with $32.1 million of availability under the 2019 Senior Credit Facility borrowing base of $125 million. 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, costless collars and basis swaps. 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 2019 Results

- We grew production by 85% in 2019 as we conducted drilling or completion operations on 16 wells, adding 9 gross (7.2 net) wells to production in the Haynesville Shale Trend;
- We grew reserves by 8% to 517 Bcfe of proved oil and natural gas reserves with a PV-10 of $297 million;
- We increased our oil and natural gas revenues to $118.4 million, representing an increase of 35% from 2018;
- We grew net cash provided by operating activities by 61% in 2019 to $79.1 million and generated net income of $13.3 million or $1.09 per share (basic) and $0.96 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 40,000 gross (22,000 net) acres as of December 31, 2019 producing from or prospective for the Haynesville Shale Trend. We incurred drilling or completion costs on 16 wells in 2019, spending $93.4 million of which $0.5 million was leasehold cost. We added 9 gross (7.2 net) wells to production in 2019. Our net production volumes from our Haynesville Shale Trend wells represented approximately 97% of our total equivalent production on a Mcfe basis and substantially all of our total natural gas production for the year ended December 31, 2019.

Tuscaloosa Marine Shale Trend

We held approximately 48,000 gross (33,000 net) acres in the TMS as of December 31, 2019 with approximately 47,000 gross (33,000 net) acres held by production. During 2019, we 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 2% of our total equivalent production on a Mcfe basis and approximately 99% of our total oil production for the year ended December 31, 2019. During 2019, we did not spend any capital in the TMS; however, we did spend $1.0 million on workover expense activities to maintain volumes on producing wells.

Eagle Ford Shale Trend

As of December 31, 2019, we retained approximately 12,000 net acres of undeveloped leasehold in the Eagle Ford Shale Trend in Frio County, Texas.

Results of Operations

For the year ended December 31, 2019, we reported net income of $13.3 million, or $1.09 per share (basic) and $0.96 per share (diluted), on oil and gas revenues of $118.4 million. This compares to net income of $1.8 million, or $0.15 per share (basic) and $0.13 per share (diluted) for the year ended December 31, 2018. The recurring items that had the most material financial effect on our net income for the years ended December 31, 2019 and 2018 were increased oil and gas revenues each year offset by increased transportation and processing cost and increased depreciation, depletion and amortization cost. Additionally, we incurred gains on derivatives not designated as hedges for the year ended December 31, 2019. All of these items can be primarily attributed to our increased production volumes and our derivative contracts entered into to manage commodity price risk.

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, 2019**	**Year Ended December 31, 2018**	**Variance**	
Revenues:				
Natural gas	$ 107,966	$ 73,198	$ 34,768	47%
Oil and condensate	$ 10,387	$ 14,745	$ (4,358)	(30%)
Natural gas, oil and condensate	$ 118,353	$ 87,943	$ 30,410	35%
Net Production:				
Natural gas (Mmcf)	46,712	24,444	22,268	91%
Oil and condensate (MBbls)	171	217	(46)	(21%)
Total (Mmcfe)	47,737	25,746	21,991	85%
Average daily production (Mcfe/d)	130,787	70,537	60,250	85%
Average Realized Sales Price Per Unit:				
Natural gas (per Mcf)	$ 2.31	$ 2.99	$ (0.68)	(23%)
Natural gas (per Mcf) including the effect of realized gains/losses on derivatives	$ 2.53	$ 2.94	$ (0.41)	(14%)
Oil and condensate (per Bbl)	$ 60.77	$ 67.93	$ (7.16)	(11%)
Oil and condensate (per Bbl) including the effect of realized gains/losses on derivatives	$ 56.78	$ 59.27	$ (2.49)	(4%)
Average realized price (per Mcfe)	$ 2.48	$ 3.42	$ (0.94)	(27%)

Oil and Natural Gas Revenue

Natural gas, oil and condensate revenues increased during the year ended December 31, 2019 compared to the prior year period in 2018 reflecting an increase in natural gas production offset by decreased oil and condensate production as well as decreased realized sales prices for natural gas, oil and condensate. Increased natural gas production contributed approximately $51.5 million to our increased revenues while decreased realized prices and decreased oil and condensate production reduced revenues by $21.1 million compared to 2018. The increase in natural gas production volumes was attributed to 9 gross Haynesville Shale Trend wells put on production during 2019. We continue to concentrate our operational activities and resources on increasing natural gas production in the Haynesville Shale Trend. For the years ended December 31, 2019 and 2018, 91% and 83%, respectively, of our oil and natural gas revenue was attributable to natural gas sales.

The difference between our average realized prices inclusive and exclusive of net cash derivative settlements for the years ended December 31, 2019 and 2018 related to our oil and natural gas swap contracts. In 2019, we received a net $10.3 million on natural gas derivative settlements on a daily average of approximately 95,000 MMBtu with a weighted average fixed price of $2.90 per MMBtu and paid a net $0.7 million on oil derivative settlements on a daily average of 312 barrels at a weighted average price of $51.08 per barrel. 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.

Operating Expenses

(in thousands)	**Year Ended December 31, 2019**	**Year Ended December 31, 2018**	**Variance**	
Lease operating expenses	$ 12,371	$ 10,446	$ 1,925	18%
Production and other taxes	2,573	2,605	(32)	(1%)
Transportation and processing	20,703	11,046	9,657	87%

Per Mcfe	**Year Ended December 31, 2019**	**Year Ended December 31, 2018**	**Variance**	
Lease operating expenses	$ 0.26	$ 0.41	$ (0.15)	(37%)
Production and other taxes	$ 0.05	$ 0.10	$ (0.05)	(50%)
Transportation and processing	$ 0.43	$ 0.43	$ -	0%

Lease Operating Expense

Lease operating expense (“LOE”) increased $1.9 million to $12.4 million during the year ended December 31, 2019 compared to the prior year period. The increase in LOE between years was attributable primarily to increased natural gas production volumes which increased variable lease operating costs such as saltwater disposal and equipment rental expenses, while fixed expenses remained relatively flat between years. The per unit cost of production decreased by 37% to $0.26 per Mcfe for the year ended December 31, 2019. Per unit LOE is expected to continue to decrease as we increase production in the Haynesville Shale Trend, which carries a lower per unit LOE than the Company’s current per unit rate. We incurred $1.3 million in workover expense in 2019 and $1.4 million in 2018. The majority of the workover expense incurred in both years was attributed to our TMS wells in an effort to maintain our oil production. Lease operating expense exclusive of workover expense on a per unit basis was $0.23 and $0.35 per Mcfe for the years ended December 31, 2019 and 2018, respectively.

Production and Other Taxes

Production and other taxes includes severance and ad valorem taxes. Severance taxes were $1.6 million for the year ended December 31, 2019, which decreased by $0.2 million compared to the prior year period. Severance taxes in 2018 were higher due to a non-recurring tax rate true-up associated with our non-operated take-in-kind natural gas volumes. Ad valorem taxes were $1.0 million for the year ended December 31, 2019, which was an increase of $0.2 million compared to the prior year period. We expect ad valorem taxes to increase as our newly producing wells begin to be valued by the taxing jurisdictions. The State of Louisiana has enacted an exemption from the existing 12.5% severance tax on oil and from the $0.111 per Mcf (from July 1, 2017 through June 30, 2018), $0.122 per Mcf (from July 1, 2018 through June 30, 2019) and $0.125 per Mcf (which began on July 1, 2019) 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 wells in Northwest Louisiana are benefiting from this exemption.

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, 2019 increased while per unit expense remained flat compared to the prior year period, 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. Additionally, the wells we have recently put on production are producing from leases that stipulate that the royalty is free from transportation cost; consequently, we currently are incurring a proportionately higher transportation cost on the production from those wells. Our per unit transportation cost will continue to decrease as we increase our operated natural gas production under more favorable transportation contracts and from areas with more favorable lease terms.

(in thousands)	**Year Ended December 31, 2019**	**Year Ended December 31, 2018**	**Variance**	
Depreciation, depletion & amortization	$ 50,722	$ 26,809	$ 23,913	89%
General & administrative	20,775	19,663	1,112	6%
Other	106	7	99	1414%

Per Mcfe	**Year Ended December 31, 2019**	**Year Ended December 31, 2018**	**Variance**	
Depreciation, depletion & amortization	$ 1.06	$ 1.04	$ 0.02	2%
General & administrative	$ 0.44	$ 0.76	$ (0.32)	(42%)
Other	$ -	$ -	$ -	0%

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

DD&A expense for the year ended December 31, 2019 and 2018 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 for the year ended December 31, 2019 versus the prior year period as a result of an increase in the DD&A rate based on the 2019 reserve reports and also because of additional production volumes to which the DD&A rate was applied. Included in DD&A for the year ended December 31, 2019 was the depletion of our oil and gas properties of $50.1 million, accretion of our asset retirement obligation of $0.2 million, and $0.4 million in depreciation of our furniture and fixtures.

Impairment

Our Full Cost Ceiling Test performed quarterly did not require recording an impairment in 2019 or 2018.

General and Administrative Expense ("G&A")

General and Administrative Expense for the year ended December 31, 2019 was $20.8 million, which included $6.3 million of share based compensation. The $1.1 million increase in G&A expense for the year ended December 31, 2019 compared to the prior year period was substantially attributed to an increase in the annual performance bonus accrual and payment of special bonuses partially offset by a decrease in share based compensation. The special bonus was granted to non-executives in 2019 in lieu of any year-end 2018 restricted stock grants. We capitalized $3.7 million and $3.5 million of G&A directly attributed to our capital development to the full cost pool for the year ended December 31, 2019 and December 31, 2018, respectively. Our G&A expense per unit of production decreased by 42% in 2019 and is expected to continue to decrease entirely due to our increasing production volumes with similar G&A expenses.

Other Income (Expense)

	Year Ended December 31, 2019	Year Ended December 31, 2018	Variance	
Other Income (Expense):				
Interest expense	$ (11,001)	$ (11,944)	$ (943)	(8%)
Interest income and other	25	508	(483)	(95%)
Gain (loss) on derivatives not designated as hedges	15,010	(3,986)	18,996	477%
Loss on early extinguishment of debt	(1,846)	-	(1,846)	(100%)
Reorganization items loss, net	-	(305)	305	100%
Income tax benefit	-	57	(57)	(100%)
Average funded borrowings adjusted for debt discount	$ 86,493	$ 55,672		
Average funded borrowings	$ 89,909	$ 62,476		

Interest Expense

Interest expense for the year ended December 31, 2019 included $0.9 million incurred on the 2017 Senior Credit Facility, $3.4 million incurred on the 2019 Senior Credit Facility, $5.3 million incurred on the Convertible Second Lien Notes, and $1.4 million incurred on the New 2L Notes. The interest on the Convertible Second Lien Notes and New 2L Notes was all non-cash consisting of paid-in-kind interest of $4.0 million, amortized debt discount of $2.6 million and amortization of debt issuance costs of $0.1 million.

Interest expense for the year ended December 31, 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 paid-in-kind interest of $6.7 million and amortized debt discount of $4.1 million.

Interest expense decreased for the year ended December 31, 2019 compared to the prior year period due to a reduction in our average interest rate on our debt offset by an increase in our funded debt amount, mainly resulting from additional borrowings on our 2019 Senior Credit Facility and accretion of the paid-in-kind interest on our New 2L Notes. On May 29, 2019, we redeemed our Convertible Second Lien Notes using borrowings from our 2019 Senior Credit Facility and recorded a $1.8 million loss on early extinguishment of debt. On May 31, 2019, we issued $12.0 million of new convertible second lien notes. These transactions resulted in, and will continue to result, in the Company incurring less interest expense overall because a large portion of our debt was moved to the 2019 Senior Credit Facility, which has a lower interest rate, but an increase in interest payable in cash.

Interest Income and Other

Interest income and other for the year ended December 31, 2019 was less than $0.1 million.

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.

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.

Gain on commodity derivatives not designated as hedges of $15.0 million for the year ended December 31, 2019 was comprised of a mark-to-market gain of $5.4 million, representing the change in fair value of our unsettled derivative contracts, and a gain of $9.6 million from net cash settlements. The mark-to-market gain represented an $8.2 million gain in the fair value of our natural gas derivative contracts, offset by a $2.4 million loss in the fair value of our basis swaps and a $0.4 million loss in the fair value our oil derivative contracts. The gain on cash settlements reflected a net $10.3 million received from our counter-parties on settlement of our natural gas derivatives offset by a net $0.7 million paid to our counter-parties on settlement of oil derivatives.

Loss on commodity derivatives not designated as hedges for the year ended December 31, 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.

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 no income tax benefit or expense for the year ended December 31, 2019 and a $0.1 million income tax benefit for the year ended December 31, 2018. We maintained a valuation allowance at December 31, 2019, 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 commodity prices and our recent history of tax net operating losses in 2018 and prior years) that led to a conclusion that based upon the more-likely-than-not standard of the accounting literature our deferred tax assets were unrecoverable. The income tax benefit recorded in 2018 was due to the adjustment to projected refund of AMT credits for which we also recorded a non-current deferred tax asset for the amount we expected to receive in 2019 and future tax years.

Adjusted EBITDA

Adjusted EBITDA grew by 65% to $79.0 million in 2019. 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.

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, 2019	Year Ended December 31, 2018
Net income (US GAAP)	$ 13,288	$ 1,750
Depreciation, depletion and amortization	50,722	26,809
Income tax benefit	-	(57)
Share based compensation expense (non-cash)	6,400	6,545
Interest expense	11,001	11,944
Loss on reorganization	-	305
(Gain) loss on commodity derivatives not designated as hedges	(15,010)	3,986
Net cash received (paid) in settlement of derivative instruments	9,560	(3,236)
Loss on early extinguishment of debt	1,846	-
Other items (1)	1,146	(96)
Adjusted EBITDA	$ 78,953	$ 47,950

(1) Other items include $1.2 million and zero, respectively, from the impact of accounting for operating leases under ASC 842 as well as interest income, reorganization items and other non-recurring income and 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 2019 were cash on hand, cash flow from operating activities of $79.1 million, $21.2 million net proceeds from borrowings on our senior credit facilities and the issuance of the New 2L Notes, and cash proceeds of $1.3 million from asset sales. We used $99.3 million in cash to fund our drilling and development capital program, $2.8 million to pay issuance costs related to our debt and $2.1 million for purchases of treasury stock for tax withholding purposes related to stock compensation. We currently plan to fund our operations and capital expenditures for 2020 through a combination of cash on hand, cash from operating activities and borrowings (if any) under the 2019 Senior Credit Facility, although we may from time to time consider other funding alternatives.

On May 14, 2019, the Company entered into a Second Amended and Restated Senior Secured Revolving Credit Agreement (the “2019 Credit Agreement”) among the Company, the Subsidiary, as borrower (in such capacity, the “Borrower”), SunTrust Bank, as administrative agent (the “Administrative Agent”), and certain lenders that are party thereto, which provides for revolving loans of up to the borrowing base then in effect (the “2019 Senior Credit Facility”). The 2019 Senior Credit Facility amended, restated and refinanced the obligations under our 2017 Credit Agreement.

The 2019 Senior Credit Facility matures (a) May 14, 2024 or b) December 3, 2020, if the New 2L Notes (as defined below) have not been voluntarily redeemed, repurchased, refinanced or otherwise retired by December 3, 2020, which is the date that is 180 days prior to the “Maturity Date” as defined in the indenture governing the New 2L Notes (the “New 2L Notes Indenture”) as in effect on the issuance date of the New 2L Notes. The maximum credit amount under the 2019 Senior Credit Facility is $500 million with a current borrowing base of $125 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, 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 at their sole discretion and consistent with their oil and gas lending criteria at the time of the relevant redetermination. The Borrower may also request the issuance of letters of credit under the 2019 Credit Agreement in an aggregate amount up to $10 million, which reduce the amount of available borrowings under the borrowing base in the amount of such issued and outstanding letters of credit.

On May 14, 2019, the Company and the Subsidiary entered into a purchase agreement with certain funds and accounts managed by Franklin Advisers, Inc., as investment manager (each such fund or account, together with its successors and assigns, a “New 2L Notes Purchaser”) pursuant to which the Company issued to the New 2L Notes Purchasers (the “New 2L Notes Offering”) $12.0 million aggregate principal amount of the Company’s 13.50% Convertible Second Lien Senior Secured Notes due 2021 (the “New 2L Notes”). The closing of the New 2L Notes Offering occurred on May 31, 2019. Proceeds from the sale of the New 2L Notes were primarily used to pay down outstanding borrowings under the 2019 Senior Credit Facility. Holders of the New 2L Notes have a second priority lien on all assets of the Company.

The New 2L Notes, as set forth in the New 2L Notes Indenture, are scheduled to mature on May 31, 2021. The New 2L 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 New 2L Notes by increasing the principal amount of the outstanding New 2L Notes.

We exited 2019 with $1.5 million of cash on hand and $92.9 million of outstanding borrowings with $32.1 million of availability under the current borrowing base of $125.0 million on the 2019 Senior Credit Facility. Due to the timing of payment of our capital expenditures, we reflected a working capital deficit of $19.7 million as of December 31, 2019. To the extent we operate with a working capital deficit, we expect such deficit to be offset by liquidity available under our 2019 Senior Credit Facility. We are beginning 2020 with $33.6 million in immediately available capital resources. See *Note 5—Debt* in the *Notes to Consolidated Financial Statements* in *“Item 8—Financial Statements and Supplementary Data”* of the Annual Report on Form 10-K for more information on the 2019 Senior Credit Facility and the New 2L Notes.

Outlook

Our total capital expenditures for 2020 are expected to be approximately $55 to $65 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 13 gross (5.8 net) wells utilizing improved completion techniques.

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

In addition, to support future cash flows, we entered into strategic derivative positions as of December 31, 2019 covering approximately 47% of our anticipated natural gas sales volumes for 2020 and 54% of our anticipated oil sales volumes for 2020. See *Note 9—Derivative Activities in the Notes to Consolidated Financial Statements in "Item 8—Financial Statements and Supplementary Data" 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 2019 Senior Credit Facility;
- issuance of debt securities;
- joint ventures in our TMS and/or Haynesville Shale Trend acreage;
- sale of non-core assets; and
- issuance of equity securities if favorable conditions exist.

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

Cash flow statement information:	**Year Ended December 31, 2019**	**Year Ended December 31, 2018**
Net Cash:		
Provided by operating activities	$ 79,071	$ 49,186
Used in investing activities	(97,967)	(78,249)
Provided by financing activities	16,280	7,139
Decrease in cash and cash equivalents	$ (2,616)	$ (21,924)

At December 31, 2019, our capital expenditures at the end of 2019 resulted in a working capital deficit of $19.7 million, which was more than offset by the liquidity available under the 2019 Senior Credit Facility. We had approximately $104.4 million in long-term debt as of December 31, 2019.

Cash Flows

For the Year Ended December 31, 2019

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 operating cash flows. Net cash provided by operating activities for the year ended December 31, 2019 was $79.1 million including operating cash flows before working capital changes of $75.5 million which included $9.6 million for settlements of derivative contracts. The substantial increase in cash provided by operating activities in 2019 compared to 2018 was attributable to a 35% increase in oil and natural gas revenues driven by an 85% increase in equivalent production volumes.

Investing activities: Net cash used in investing activities was $98.0 million for the year ended December 31, 2019, which reflected cash expended on capital projects of $99.3 million reduced by $1.3 million cash proceeds received from sales of oil and gas properties. We recorded $98.4 million in capital expenditures in this period, which reflected the capitalization of $0.3 million in asset retirement obligation and $0.7 million of non-cash internal cost reduced by a net $1.9 million in the change of the capital expenditure accrual. We conducted drilling and completion operations on 16 gross wells bringing 9 gross (7.2 net) wells on production in the Haynesville Shale Trend during the year ended December 31, 2019, and we capitalized $5.0 million in internal costs. We had 9 gross (4.9 net) wells waiting completion at December 31, 2019.

Financing activities: Net cash provided by financing activities for the year ended December 31, 2019 was $16.3 million consisting of net draws of $65.9 million on the Company's senior credit facilities reduced by $44.7 million net payments on our convertible second lien notes, $2.1 million for the purchase of shares withheld from employee stock awards for the payments of taxes and $2.8 million of debt issuance cost paid upon the amendment of the 2019 Senior Credit Facility and issuance of the New 2L Notes.

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.

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.

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

	December 31, 2019			December 31, 2018		
	Principal	**Carrying Amount**	**Fair Value**	**Principal**	**Carrying Amount**	**Fair Value**
2017 Senior Credit Facility (1)	$ -	$ -	$ -	$ 27,000	$ 27,000	$ 27,000
2019 Senior Credit Facility (1)	92,900	92,900	92,900	-	-	-
Convertible Second Lien Notes (2)	-	-	-	53,691	49,820	60,857
New 2L Notes (3)	12,969	11,535	12,952	-	-	-
Total debt	$ 105,869	$ 104,435	$ 105,852	$ 80,691	$ 76,820	$ 87,857

(1) The carrying amount for the 2017 Senior Credit Facility and the 2019 Senior Credit Facility represent fair value as they were fully secured.

(2) The debt discount was being amortized using the effective interest rate method based upon a maturity date of August 30, 2019 until the Convertible Second Lien Notes were fully paid off on May 29, 2019.

(3) The debt discount is being amortized using the effective interest rate method based upon a maturity date of May 31, 2021. The principal includes paid-in-kind interest of $1.0 million as of December 31, 2019. The carrying value includes $1.1 million of unamortized debt discount and $0.3 million of unamortized issuance cost at December 31, 2019. The fair value of the New 2L Notes, a Level 2 fair value estimate, was obtained by using the last known sale price for the value on December 31, 2019.

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, 2019		Year Ended December 31, 2018	
	Interest Expense	**Effective Interest Rate**	**Interest Expense**	**Effective Interest Rate**
2017 Senior Credit Facility	$ 872	7.2%	$ 1,130	8.9%
2019 Senior Credit Facility	3,409	6.0%	-	-
Convertible Second Lien Notes (1)	5,304	24.1%	10,814	23.9%
New 2L Notes (2)	1,416	21.6%	-	-
Total	$ 11,001		$ 11,944	

(1) The Convertible Second Lien Notes had a coupon interest rate of 13.50%; however, the discount recorded due to the convertibility of the notes increased the effective interest rate to 24.1% for the year ended December 31, 2019 (until payoff on May 29, 2019) and 23.9% for the year ended December 31, 2018. Interest expense for the year ended December 31, 2019 included $2.3 million of debt discount amortization and $3.0 million of paid-in-kind interest. Interest expense for the year ended December 31, 2018 included $4.1 million of debt discount amortization and $6.7 million of paid-in-kind interest.

(2) The New 2L Notes have a coupon interest rate of 13.50%; however, the discount recorded due to the convertibility of the notes increased the effective interest rate to 21.6% for the year ended December 31, 2019. Interest expense for the year ended December 31, 2019 included $0.3 million of debt discount amortization and $1.0 million of accrued interest to be paid in-kind.

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, 2019. In addition to the contractual obligations presented in the table below, our Consolidated Balance Sheet at December 31, 2019 reflects accrued interest on our bank debt of $0.2 million payable in the first quarter of 2020. For additional information see *Note 5—Debt*, *Note 10—Commitments and Contingencies* and *Note 11—Leases* 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**	**2020**	**2021**	**2022**	**2023**	**2024 and After**
Debt	5	$ 105,869	$ -	$ 12,969	$ -	$ -	$ 92,900
Office space leases	11	2,353	1,540	813	-	-	-
Operations contracts		2,491	2,491	-	-	-	-
Total contractual obligations (1)		$ 110,713	$ 4,031	$ 13,782	$ -	$ -	$ 92,900

(1) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $4.2 million as of December 31, 2019. We record a separate liability for the asset retirement obligations. See *Note 4—Asset Retirement Obligation* in the *Notes to Consolidated Financial Statements in "Item 8—Financial Statements and Supplementary Data"* of this Annual Report on Form 10-K.

Summary of Critical Accounting Policies and Estimates

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

Proved Oil and Natural Gas Reserves

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

While the estimates of our proved reserves at December 31, 2019 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 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.

Full Cost Ceiling Test

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

Fair Value Measurement

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

Asset Retirement Obligations

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

Income Taxes

We are subject to income and other related taxes in areas in which we operate. When recording income tax expense, certain estimates are required by management due to timing and the impact of future events on when income tax expenses and benefits are recognized by us. We periodically evaluate our tax operating loss and other carry-forwards to determine whether a gross deferred tax asset, as well as a related valuation allowance, should be recognized in our financial statements.

Accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. See *Note 1—Description of Business and Summary of Significant Accounting Policies—Income Taxes* and *Note 7—Income Taxes* in the *Notes to Consolidated Financial Statements* in *“Item 8— Financial Statements and Supplementary Data”* of this Annual Report on Form 10-K.

Share-based Compensation Plans

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

New Accounting Pronouncements

See *Note 1—Description of Business and Summary of Significant Accounting Policies—New Accounting Pronouncements* in the *Notes to Consolidated Financial Statements* in *“Item 8—Financial Statements and Supplementary Data”* of this Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

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

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

As a smaller reporting company, we are not required to provide the information required by this Item 7A.

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, 2019.

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, 2019 and 2018, 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, 2019 and 2018, 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, 2020

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

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

	December 31, 2019	December 31, 2018
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,452	$ 4,068
Accounts receivable, trade and other, net of allowance	1,131	744
Accrued oil and natural gas revenue	11,345	14,464
Fair value of oil and natural gas derivatives	8,537	803
Inventory	234	596
Prepaid expenses and other	549	533
Total current assets	23,248	21,208
PROPERTY AND EQUIPMENT:		
Unevaluated properties	123	180
Oil and gas properties (full cost method)	302,859	206,097
Furniture, fixtures and equipment	4,450	1,360
	307,432	207,637
Less: Accumulated depletion, depreciation and amortization	(94,124)	(42,447)
Net property and equipment	213,308	165,190
Fair value of oil and natural gas derivatives	31	-
Deferred tax asset	393	786
Other	2,338	580
TOTAL ASSETS	$ 239,318	$ 187,764
LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)		
CURRENT LIABILITIES:		
Accounts payable	$ 26,348	$ 25,734
Accrued liabilities	16,615	16,518
Total current liabilities	42,963	42,252
Long term debt, net	104,435	76,820
Accrued abandonment costs	4,169	3,791
Fair value of oil and natural gas derivatives	2,786	471
Non-current operating lease liability	800	-
Total liabilities	155,153	123,334
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 12,532,550 shares issued and outstanding at December 31, 2019 and $0.01 par value, 75,000,000 shares authorized, and 12,150,918 shares issued and outstanding at December 31, 2018	125	122
Additional paid-in capital	81,305	74,861
Retained earnings (deficit)	2,735	(10,553)
Total stockholders' equity	84,165	64,430
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 239,318	$ 187,764

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF OPERATIONS
(In Thousands, Except Per Share Amounts)

	Year Ended December 31, 2019	Year Ended December 31, 2018
REVENUES:		
Oil and natural gas revenues	$ 118,353	$ 87,943
Other	(3)	53
	118,350	87,996
OPERATING EXPENSES:		
Lease operating expense	12,371	10,446
Production and other taxes	2,573	2,605
Transportation and processing	20,703	11,046
Depreciation, depletion, and amortization	50,722	26,809
General and administrative	20,775	19,663
Other	106	7
	107,250	70,576
Operating income	11,100	17,420
OTHER INCOME (EXPENSE):		
Interest expense	(11,001)	(11,944)
Interest income and other	25	508
Gain (loss) on derivatives not designated as hedges	15,010	(3,986)
Loss on early extinguishment of debt	(1,846)	-
	2,188	(15,422)
Reorganization items, net	-	(305)
Income before income taxes	13,288	1,693
Income tax benefit	-	57
Net income	$ 13,288	$ 1,750
PER COMMON SHARE:		
Net income per common share—basic	$ 1.09	$ 0.15
Net income per common share—diluted	$ 0.96	$ 0.13
Weighted average shares of common stock outstanding—basic	12,233	11,622
Weighted average shares of common stock outstanding—diluted	13,895	13,665

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)

	Year Ended December 31, 2019	Year Ended December 31, 2018
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 13,288	$ 1,750
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation and amortization	50,722	26,809
Right of use asset depreciation	1,252	-
Deferred income taxes	-	(57)
(Gain) loss on derivatives not designated as hedges	(15,010)	3,986
Net cash received (paid) in settlement of derivative instruments	9,560	(3,236)
Share-based compensation (non-cash)	6,400	6,545
Loss on early extinguishment of debt	1,846	-
Amortization of finance cost, debt discount, paid-in-kind interest and accretion	7,097	10,983
Reorganization items (non-cash)	-	(476)
Loss (gain) from material transfers & inventory sales & write-downs	327	(32)
Change in assets and liabilities:		
Accounts receivable, trade and other, net of allowance	6	835
Accrued oil and natural gas revenue	3,119	(9,506)
Inventory	35	-
Prepaid expenses and other	(45)	(249)
Accounts payable	614	8,530
Accrued liabilities	(140)	3,304
Net cash provided by operating activities	79,071	49,186
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(99,301)	(105,088)
Proceeds from sale of assets	1,334	26,839
Net cash used in investing activities	(97,967)	(78,249)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Principal payments of bank borrowings	(49,500)	(16,723)
Proceeds from bank borrowings	115,400	27,000
Repayment of Convertible Second Lien Notes	(56,728)	-
Proceeds from New 2L Notes	12,000	-
Issuance cost, net	(2,795)	(49)
Other including purchase of treasury stock	(2,097)	(3,089)
Net cash provided by financing activities	16,280	7,139
Decrease in cash and cash equivalents	(2,616)	(21,924)
Cash and cash equivalents, beginning of period	4,068	25,992
Cash and cash equivalents, end of period	$ 1,452	$ 4,068
Supplemental disclosures of cash flow information:		
Cash paid during the year for interest	$ 4,137	$ 575
Cash paid during the year for taxes	$ -	$ -
Decrease in non-cash capital expenditures	$ (1,911)	$ (2,425)

See accompanying notes to consolidated financial statements.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY/(DEFICIT)
(In Thousands)

	Preferred Stock		Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings/ (Deficit)	Total Stockholders' Equity/(Deficit)
	Shares	Value	Shares	Value		Shares	Value		
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
Net income	-	-	-	-	-	-	-	13,288	13,288
Share-based compensation	-	-	-	-	7,221	-	-	-	7,221
Restricted stock vesting & other	-	-	232	4	(90)	(208)	(2,098)	-	(2,184)
Convertible Second Lien Notes warrant exercises	-	-	150	1	(20)	-	-	-	(19)
New 2L Notes conversion	-	-	-	-	1,429	-	-	-	1,429
Treasury stock activity	-	-	-	(2)	(2,096)	208	2,098	-	-
Balance at December 31, 2019	-	$ -	12,533	$ 125	$ 81,305	-	$ -	$ 2,735	$ 84,165

See accompanying notes to consolidated financial statements.

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, 2019 and 2018 (in thousands):

	December 31,	
	2019	**2018**
Trade payables	$ 11,461	$ 8,633
Revenue payables	14,483	16,665
Prepayments from partners	-	132
Other	404	304
Total Accounts payable	$ 26,348	$ 25,734

Accrued Liabilities—Accrued liabilities consisted of the following items as of December 31, 2019 and 2018 (in thousands):

	December 31,	
	2019	**2018**
Accrued capital expenditures	$ 6,175	$ 8,086
Accrued lease operating expense	989	1,100
Accrued production and other taxes	430	338
Accrued transportation and gathering	2,258	1,888
Accrued performance bonus	4,642	3,420
Accrued interest	208	443
Accrued office lease	1,414	598
Accrued general and administrative expense and other	499	645
Total Accrued liabilities	$ 16,615	$ 16,518

Inventory—Inventory consisted of equipment, 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, 2019 and December 31, 2018, we transferred $0.3 million and $6.0 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 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, 2019 and December 31, 2018 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.

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 senior credit facilities 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, 2019 and December 31, 2018, 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, 2019 and 2018, 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*.

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, 2019 and 2018 are as follows:

	Year Ended December 31,	
	2019	2018
CIMA Energy, LP	39%	41%
Shell	19%	0%
ETC	19%	15%
CES	10%	8%
Genesis Crude Oil LP	8%	13%

Share-based Compensation—We account for our share-based transactions using the fair value as of the grant date and recognize compensation expense over the requisite service period. See *Note 3*.

Guarantee—As of December 31, 2019 Goodrich Petroleum Company LLC, the wholly owned subsidiary of Goodrich Petroleum Corporation, was the Subsidiary Guarantor of our New 2L Notes (as defined below). The parent company has no independent assets or operations, the guarantee is full and unconditional, and the parent has no subsidiaries other than Goodrich Petroleum Company LLC.

Debt Issuance Cost—The Company records debt issuance costs associated with its New 2L Notes (and previously with its Convertible Second Lien Notes, both as defined below) as a contra balance to long term debt, net in our Consolidated Balance Sheets, which is amortized straight-line over the life of the respective 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 December 2019, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2019-12, Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes. The amendments in this ASU adds new guidance to simplify accounting for income taxes, changes the accounting for certain income tax transactions and makes minor improvements to the codification. For public entities, the amendments in this ASU are effective for fiscal periods beginning after December 15, 2020, including interim periods therein. We are evaluating the expected impact these amendments will have on our consolidated financial statements; however, we do not expect a material impact from the adoption of this ASU.

In August 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 no do anticipate a material impact from the adoption of this ASU.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2019 and December 31, 2018, receivables from contracts with customers were $11.3 million and $14.5 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, 2019			
(In thousands)	**Oil Revenue**	**Gas Revenue**	**NGL Revenue**	**Total Oil and Natural Gas Revenues**
Operated	$ 9,961	$ 91,811	$ -	$ 101,772
Non-operated	426	16,142	13	16,581
Total oil and natural gas revenues	$ 10,387	$ 107,953	$ 13	$ 118,353

	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

NOTE 3—Share-based Compensation Plans

Overview

The Company had one effective share-based compensation plan as of December 31, 2019 and December 31, 2018, 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, provides for awards of restricted stock, options, performance awards, phantom shares and stock appreciation rights to directors, officers, employees, and consultants. 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.

In 2019, the Company granted approximately (i) 205,000 restricted stock units (“RSUs”) to employees which will generally vest over three years from the date of grant, subject to continued employment, (ii) 205,000 performance share units (“PSUs”), which will generally cliff vest after a three-year performance period from the date of grant, subject to continued employment and the level of achievement with respect to applicable performance metrics and (iii) 81,000 RSU's to non-employee directors which will generally cliff vest in 12 months following the date of grant, subject to continued service. In 2018, there were no material issuances of RSUs granted to employees and the only issuances to employees under the LTIP were 201,969 shares of common stock issued in settlement for performance bonuses earned in 2017. In December 2018, 45,160 RSUs were granted to non-employee directors which vested in 12 months following the date of grant. As of December 31, 2019, the Company had no further shares available for future issuance under the LTIP, assuming that the PSUs awarded in 2017 and 2019 will vest at the maximum payouts of 250% and 200%, respectively.

Performance Share Unit Awards

In December 2019, the Company granted approximately 205,000 PSUs. The PSU 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 after a three-year performance period from the date of grant. The actual number of shares to be earned and that will cliff vest is subject to a market condition, which is based on company stock price performance. The range of shares of common stock which may be earned by an award recipient ranges from zero to 200% of the initial PSUs 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 a share of the Company's common stock 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 was assumed to be zero since the Company does not anticipate paying dividends within the vesting term of the PSU’s.

- 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.

The grant date fair value of each PSU as determined by the Monte Carlo simulation model was $10.43, which was based on the following assumptions:

	2019
Number of simulations	250,000
Grant price	$ 10.43
Volatility factor	49.3%
Dividend yield	—
Risk-free interest rate	2%
Expected term (in years)	P3Y

The fair value of the PSUs granted in 2019 of $2.1 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, 2019, unrecognized compensation costs related to the unvested PSUs granted in 2019 was $2.1 million and will be recognized as share-based compensation expense, net of amounts capitalized, over a weighted-average period of 2.95 years.

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, 2019 and 2018:

	Year Ended December 31,	
2016 Long Term Incentive Plan	**2019**	**2018**
RSU expense - employees	$ 4,521	$ 4,702
PSU expense	1,952	1,893
RSU expense - directors	664	595
Total share-based compensation	$ 7,137	$ 7,190
Capitalized and lease operating expense share-based compensation	(835)	(747)
Net share-based compensation - general and administrative expense	$ 6,302	$ 6,443

RSUs and PSUs awarded under the LTIP generally have a vesting period between 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 the employment or service relationship, as applicable, ends before the end of the vesting period. Certain RSUs and PSUs provide for accelerated vesting in certain limited circumstances. RSUs and PSUs are not considered to be currently issued and outstanding until the restrictions lapse and/or they vest.

RSU and PSU activity and changes under the LTIP for the years ended December 31, 2019 and 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, 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
Granted	294,871	204,755	499,626	9.96	10.43	10.16	2,938	2,136	5,074
Vested	(530,446)	-	(530,446)	10.18	-	10.18	(5,138)	-	(5,138)
Forfeited	(9,032)	-	(9,032)	13.84	-	13.84	(125)	-	(125)
Unvested at December 31, 2019	416,530	604,143	1,020,673	$ 9.92	$ 13.64	$ 12.12	$ 2,328	$ 8,243	$ 10,571

(1) Includes 201,969 shares of common stock issued in settlement for 2017 performance bonuses, which were paid in 2018.

As of December 31, 2019 and 2018, 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, 2019	$ 3,969	$ 4,283	$ 8,252	1.95	1.93	1.94
December 31, 2018	$ 6,340	$ 4,100	$ 10,440	1.35	1.96	1.59

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, 2019	December 31, 2018
Beginning balance	$ 3,791	$ 3,367
Liabilities incurred	224	303
Revisions in estimated liabilities (1)	63	47
Liabilities settled	(4)	(13)
Accretion expense	297	262
Dispositions (2)	(202)	(175)
Ending balance	$ 4,169	$ 3,791
Current liability	$ -	$ -
Long term liability	$ 4,169	$ 3,791

(1) Changes in estimated costs and timing of plugging and abandoning gave rise to the revision in estimated liabilities.
(2) See *Note 12* for further information on the dispositions during the year ended December 31, 2019.

NOTE 5—Debt

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

	December 31, 2019			December 31, 2018		
	Principal	Carrying Amount	Fair Value	Principal	Carrying Amount	Fair Value
2017 Senior Credit Facility (1)	$ -	$ -	$ -	$ 27,000	$ 27,000	$ 27,000
2019 Senior Credit Facility (1)	92,900	92,900	92,900	-	-	-
Convertible Second Lien Notes (2)	-	-	-	53,691	49,820	60,857
New 2L Notes (3)	12,969	11,535	12,952	-	-	-
Total debt	$ 105,869	$ 104,435	$ 105,852	$ 80,691	$ 76,820	$ 87,857

(1) The carrying amount for the 2017 Senior Credit Facility and the 2019 Senior Credit Facility represent fair value as they were fully secured.
(2) The debt discount was being amortized using the effective interest rate method based upon a maturity date of August 30, 2019 until the Convertible Second Lien Notes were fully paid off on May 29, 2019.
(3) The debt discount is being amortized using the effective interest rate method based upon a maturity date of May 31, 2021. The principal includes paid-in-kind interest of $1.0 million as of December 31, 2019. The carrying value includes $1.1 million of unamortized debt discount and $0.3 million of unamortized issuance cost at December 31, 2019. The fair value of the New 2L Notes, a Level 2 fair value estimate, was obtained by using the last known sale price for the value on December 31, 2019.

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, 2019		Year Ended December 31, 2018	
	Interest Expense	Effective Interest Rate	Interest Expense	Effective Interest Rate
2017 Senior Credit Facility	$ 872	7.2%	$ 1,130	8.9%
2019 Senior Credit Facility	3,409	6.0%	-	-
Convertible Second Lien Notes (1)	5,304	24.1%	10,814	23.9%
New 2L Notes (2)	1,416	21.6%	-	-
Total	$ 11,001		$ 11,944	

(1) The Convertible Second Lien Notes had a coupon interest rate of 13.50%; however, the discount recorded due to the convertibility of the notes increased the effective interest rate to 24.1% for the year ended December 31, 2019 (until payoff on May 29, 2019) and 23.9% for the year ended December 31, 2018. Interest expense for the year ended December 31, 2019 included $2.3 million of debt discount amortization and $3.0 million of paid-in-kind interest. Interest expense for the year ended December 31, 2018 included $4.1 million of debt discount amortization and $6.7 million of paid-in-kind interest.
(2) The New 2L Notes have a coupon interest rate of 13.50%; however, the discount recorded due to the convertibility of the notes increased the effective interest rate to 21.6% for the year ended December 31, 2019. Interest expense for the year ended December 31, 2019 included $0.3 million of debt discount amortization and $1.0 million of accrued interest to be paid in-kind.

2017 Senior Credit Facility

On October 17, 2017, the Company entered into the Amended and Restated Senior Secured Revolving Credit Agreement (as amended, the “2017 Credit Agreement”) with the Subsidiary, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain lenders that are party thereto, which provided for revolving loans of up to the borrowing base then in effect (as amended, the “2017 Senior Credit Facility”). The 2017 Senior Credit Facility was set to mature on (a) October 17, 2021 or (b) December 30, 2019, if the Convertible Second Lien Notes had not been voluntarily redeemed, repurchased, refinanced or otherwise retired by December 30, 2019. The maximum credit amount under the 2017 Senior Credit Facility when it was paid off in full on May 14, 2019 was $250.0 million with a borrowing base of $75.0 million.

All amounts outstanding under the 2017 Senior Credit Facility bore 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 was utilized, or (ii) adjusted LIBOR plus an applicable margin ranging from 2.75% to 3.75%, depending on the percentage of the borrowing base that was utilized. Undrawn amounts under the 2017 Senior Credit Facility were subject to a 0.50% commitment fee.

The obligations under the 2017 Credit Agreement were secured by a first lien security interest in substantially all of the assets of the Company and the Subsidiary.

On May 14, 2019, the 2017 Senior Credit Facility was paid off in full and amended, restated and refinanced into the 2019 Senior Credit Facility. In connection with the refinancing, we recorded a $0.2 million loss on early extinguishment of debt related to the remaining unamortized debt issuance costs.

2019 Senior Credit Facility

On May 14, 2019, the Company entered into a Second Amended and Restated Senior Secured Revolving Credit Agreement (the “2019 Credit Agreement”) among the Company, the Subsidiary, as borrower (in such capacity, the “Borrower”), SunTrust Bank, as administrative agent (the “Administrative Agent”), and certain lenders that are party thereto, which provides for revolving loans of up to the borrowing base then in effect (the “2019 Senior Credit Facility”).

The 2019 Senior Credit Facility matures (a) May 14, 2024 or b) December 3, 2020, if the New 2L Notes (as defined below) have not been voluntarily redeemed, repurchased, refinanced or otherwise retired by December 3, 2020, which is the date that is 180 days prior to the “Maturity Date” as defined in the indenture governing the New 2L Notes (the “New 2L Notes Indenture”) as in effect on the issuance date of the New 2L Notes. The 2019 Senior Credit Facility provides for a maximum credit amount of $500 million subject to a borrowing base limitation, which originally was $115 million. The borrowing base was increased to $125 million in August of 2019 and is scheduled to be redetermined thereafter 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 at their sole discretion and consistent with their oil and gas lending criteria at the time of the relevant redetermination. The Borrower may also request the issuance of letters of credit under the 2019 Credit Agreement in an aggregate amount up to $10 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 2019 Senior Credit Facility 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 1.50% to 2.50%, depending on the percentage of the borrowing base that is utilized, or (ii) adjusted LIBOR plus an applicable margin from 2.50% to 3.50%, depending on the percentage of the borrowing base that is utilized. Undrawn amounts under the 2019 Senior Credit Facility are subject to a commitment fee ranging from 0.375% to 0.50%, depending on the percentage of the borrowing base that is utilized. To the extent that a payment default exists and is continuing, all amounts outstanding under the 2019 Senior Credit Facility will bear interest at 2.0% per annum above the rate and margin otherwise applicable thereto. As of December 31, 2019, the weighted average interest rate on the borrowings from the 2019 Senior Credit Facility was 5.039%. The obligations under the 2019 Credit Agreement are guaranteed by the Company and secured by a first lien security interest in substantially all of the assets of the Company and the Borrower.

The 2019 Credit Agreement contains certain customary representations and warranties, affirmative and negative covenants and events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the 2019 Senior Credit Facility to be immediately due and payable. The 2019 Credit Agreement also contains certain financial covenants, including the maintenance of (i) a ratio of Net Funded Debt to EBITDAX not to exceed 4.00 to 1.00 as of the last day of any fiscal quarter, (ii) a current ratio (based on the ratio of current assets to current liabilities as defined in the 2019 Credit Agreement) not to be less than 1.00 to 1.00 and (iii) until no New 2L Notes remain outstanding, a ratio of Total Proved PV-10 attributable to the Company’s and Borrower’s Proved Reserves to Total Secured Debt (net of any Unrestricted Cash not to exceed $10 million) not to be less than 1.50 to 1.00 and minimum liquidity requirements. On May 14, 2019, the Company utilized borrowings under the 2019 Senior Credit Facility to refinance its obligations under the 2017 Senior Credit Facility and to fund the Redemption (as defined below) of the Convertible Second Lien Notes.

As of December 31, 2019, the Company had a borrowing base of $125.0 million with $92.9 million of borrowings outstanding. The Company also had $2.2 million of unamortized debt issuance costs recorded as of December 31, 2019 related to the 2019 Senior Credit Facility.

As of December 31, 2019, the Company was in compliance with all covenants within the 2019 Senior Credit Facility.

Convertible Second Lien Notes

In October 2016, the Company issued $40.0 million aggregate principal amount of the Company's 13.50% Convertible Second Lien Senior Secured Notes due 2019 (the "Convertible Second Lien Notes") along with 10-year costless warrants to acquire 2.5 million shares of common stock. Holders of the Convertible Second Lien Notes had a second priority lien on all assets of the Company, and holders of such warrants had a right to appoint two members to our Board of Directors (the "Board") as long as such warrants were outstanding.

The Convertible Second Lien Notes were scheduled 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 Convertible Second Lien Notes bore 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 also had the option under certain circumstances 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.

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 was amortized using the effective interest rate method based upon an original term through August 30, 2019. The Convertible Second Lien Notes were redeemed in full on May 29, 2019 for $56.7 million, using borrowings under the 2019 Senior Credit Facility. In connection with the redemption of the Convertible Second Lien Notes, we recorded a $1.6 million loss on early extinguishment of debt related to the remaining unamortized debt discount and debt issuance costs.

New Convertible Second Lien Notes

On May 14, 2019, the Company and the Subsidiary entered into a purchase agreement with certain funds and accounts managed by Franklin Advisers, Inc., as investment manager (each such fund or account, together with its successors and assigns, a "New 2L Notes Purchaser") pursuant to which the Company issued to the New 2L Notes Purchasers (the "New 2L Notes Offering") $12.0 million aggregate principal amount of the Company's 13.50% Convertible Second Lien Senior Secured Notes due 2021 (the "New 2L Notes"). The closing of the New 2L Notes Offering occurred on May 31, 2019. Proceeds from the sale of the New 2L Notes were primarily used to pay down outstanding borrowings under the 2019 Senior Credit Facility. Holders of the New 2L Notes have a second priority lien on all assets of the Company.

The New 2L Notes, as set forth in the indenture governing such notes (the "New 2L Notes Indenture"), are scheduled to mature on May 31, 2021. The New 2L 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 New 2L Notes by increasing the principal amount of the outstanding New 2L Notes.

The New 2L Notes Indenture 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 sales of assets and stock; business activities; transactions with affiliates; and changes of control. The New 2L Notes Indenture also contains a financial covenant which requires the maintenance of a ratio of Total Proved PV-10 attributable to the Company's and Subsidiary's Proved Reserves (as defined in the New 2L Notes Indenture) 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.

The New 2L Notes are convertible into the Company's common stock at the conversion rate, which is the sum of the outstanding principal amount of New 2L Notes to be converted, including any accrued and unpaid interest, divided by the conversion price, which shall initially be $21.33, subject to certain adjustments as described in the New 2L Notes Indenture. Upon conversion, the Company must deliver, at its option, either (1) a number of shares of its common stock determined as set forth in the New 2L Notes Indenture, (2) cash or (3) a combination of shares of its common stock and cash; however, the Company's ability to redeem the New 2L Notes with cash is subject to the terms of the 2019 Senior Credit Agreement.

The New 2L Notes were issued and sold to the New 2L Notes Purchasers pursuant to an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereunder. The Company has completed the registration with the U.S. Securities and Exchange Commission of the resale of the New 2L Notes and the shares of common stock issuable upon conversion of The New 2L Notes.

Upon issuance of the New 2L Notes on May 31, 2019, in accordance with accounting standards related to convertible debt instruments that may be settled in cash upon conversion, we recorded a debt discount of $1.4 million, thereby reducing the $12.0 million carrying value upon issuance to $10.6 million and recorded an equity component of $1.4 million. The equity component was valued using a binomial model. The debt discount is amortized using the effective interest rate method based upon an original term through May 31, 2021.

As of December 31, 2019, $1.1 million of debt discount and $0.3 million of debt issuance costs remained to be amortized on the New 2L Notes.

As of December 31, 2019, the Company was in compliance with all covenants within the New 2L Notes Indenture.

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, 2019	Year Ended December 31, 2018
Basic net income per common share:		
Net income applicable to common stock	$ 13,288	$ 1,750
Weighted-average shares of common stock outstanding	12,233	11,622
Basic net income per common share	$ 1.09	$ 0.15
Diluted net income per common share:		
Net income applicable to common stock	$ 13,288	$ 1,750
Weighted-average shares of common stock outstanding	12,233	11,622
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	1,314	1,418
Common shares issuable on assumed conversion of restricted stock *	348	475
Diluted weighted average shares of common stock outstanding	13,895	13,665
Diluted net income per common share (1)	$ 0.96	$ 0.13
(1) Common shares issuable upon conversion of the New 2L Notes and Convertible Second Lien Notes were not included in the computation of diluted loss per common share since their inclusion would have been anti-dilutive.	608	1,875

* Common shares issuable on assumed conversion of restricted stock from 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.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 7—Income Taxes

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

	Year Ended December 31, 2019	Year Ended December 31, 2018
Current tax expense (benefit)		
Federal	$ (393)	$ (208)
State	-	-
Total current tax expense (benefit)	(393)	(208)
Deferred tax expense (benefit)		
Federal	393	151
State	-	-
Total deferred tax expense (benefit)	393	151
Total tax expense (benefit)	$ -	$ (57)

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

	Year Ended December 31, 2019	Year Ended December 31, 2018
Income tax expense (benefit)		
Tax expense at U.S. statutory rate	$ 2,790	$ 356
Disallowed executive compensation	821	841
Valuation allowance	(5,499)	(2,530)
State income taxes, net of federal benefit	718	1,194
Nondeductible expenses and other	1,170	82
Total tax expense (benefit)	$ -	$ (57)

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, 2019 and 2018:

	December 31,	
	2019	2018
Non-current deferred tax assets:		
Operating loss carry-forwards	$ 45,280	$ 38,958
State tax NOL and credits	11,611	10,278
Statutory depletion carry-forward	-	4,221
AMT tax credit carry-forward	393	786
Compensation	1,461	1,426
Contingent liabilities and other	378	784
Lease liabilities	465	-
Debt discount	-	54
Property and equipment	16,813	28,530
Total gross non-current deferred tax assets	76,401	85,037
Less valuation allowance	(74,150)	(84,181)
Net non-current deferred tax assets	2,251	856
Non-current deferred tax liabilities:		
Derivatives	(1,214)	(70)
Right of use asset	(350)	
Other	(97)	
Debt discount	(197)	-
Total non-current deferred tax liabilities	(1,858)	(70)
Net non-current deferred tax asset	$ 393	$ 786

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The valuation allowance for deferred tax assets decreased by $10.0 million to $74.2 million in 2019. The valuation allowance decreased by $5.5 million related to current year activity. Additionally, we determined that $4.5 million of our deferred tax asset, which carried a full valuation allowance, would never be recognized and therefore, we reduced both the deferred tax asset and the related valuation allowance for this in 2019. In determining the carrying value of our deferred tax assets and liabilities, we evaluated all available evidence (including commodity prices and our recent history of tax net operating losses in 2018 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 and liabilities were unrecoverable. The carrying value of our deferred tax asset of $0.4 million represents the remaining Alternative Minimum Tax (“AMT”) credits that are expected to be monetized. The tax benefit recorded for 2018 was due to adjustment of the AMT credits that were expected to be recognized by the Company as sequestration was removed from the estimate. AMT credits were partially monetized in 2016 through 2018 with the Company receiving $0.4 million in 2019. The remaining $0.4 million of AMT credits are expected to be fully refundable in tax years 2019 - 2021 regardless of the Company's regular tax liability as a result of the repeal of the Corporate AMT under the Tax Cuts and Jobs Act. The Company no longer has a valuation recorded against our estimate of refundable AMT credits. The valuation allowance has no impact on our net operating loss (“NOL”) position for tax purposes, and if we generate taxable income in future periods, we will be able to use our NOLs to offset taxes due at that time.

As of December 31, 2019, we have federal net operating loss carry-forwards of approximately $846.6 million. These carry-forwards are subject to limitation by IRC Section 382 and it is estimated $215.6 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 triggered 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 NOLs available for use of $77.0 million in Louisiana and $151.5 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, 2019. 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, 2019.

NOTE 8—Stockholders' Equity

At December 31, 2019 there were 12,532,550 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, 2019, the final 150,000 of the 10-year costless warrants associated with the Convertible Second Lien Notes were exercised. The Company received cash for the one cent par value for the issuance of the 150,000 common shares. During the year ended December 31, 2019, the Company had vestings of its share-based compensation units representing a total fair value of $5.1 million and resulting in the issuance of approximately 530,000 common shares. During the year ended December 31, 2019, the Company paid $2.1 million in cash for the purchase of approximately 208,000 Treasury shares withheld from employees upon the vesting of restricted stock awards for the payment of taxes. All shares held in Treasury were retired prior to December 31, 2019.

In connection with the issuance of the New 2L Notes, we recorded an equity component of $1.4 million. For further details, see *Note 5*.

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.

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 2019 and 2018 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, 2019	Year Ended December 31, 2018
Gain (loss) on commodity derivatives not designated as hedges, settled	$ 9,560	$ (3,236)
Gain (loss) on commodity derivatives not designated as hedges, not settled	5,450	(750)
Total gain (loss) on commodity derivatives not designated as hedges	$ 15,010	$ (3,986)

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 and reviewed periodically by the Board.

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 $8.2 million had SunTrust Bank and RBC Capital been unable to fulfill their obligations as of December 31, 2019.

As of December 31, 2019, the open positions on our outstanding commodity derivative contracts, all of which were with SunTrust Bank, RBC Capital and ARM Energy, and the associated fair values (in thousands) were as follows:

Contract Type	Average Daily Volume	Total Volume	Weighted Average Fixed Price	December 31, 2019
Crude oil swaps (Bbls)				
2020	221	80,945	$ 59.02	$ 35
2021	220	18,000	$56.58	24
			Total oil	59
Natural gas swaps (MMBtu)				
2020	51,631	18,897,000	$ 2.67	$ 7,502
2021	42,656	3,839,000	$2.64	11
Natural gas collars (MMBtu)				
2020	18,287	6,693,000	$2.40-$2.625	901
2021	27,000	2,430,000	$2.40-$2.625	(314)
			Total natural gas	8,100
Natural gas basis swaps (MMBtu)				
2020	50,000	18,300,000	NYMEX - $0.209	$ 99
2021	50,000	18,250,000	NYMEX - $0.209	(239)
2022	50,000	18,250,000	NYMEX - $0.209	(518)
2023	50,000	18,250,000	NYMEX - $0.209	(679)
2024	50,000	18,300,000	NYMEX - $0.209	(1,040)
			Total natural gas basis	(2,377)
			Total	$ 5,782

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, 2019 (in thousands). We measure the fair value of our commodity derivative contracts by applying the income approach. See *Note 1* 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	$ -	$ 8,537	$ -	$ 8,537
Fair value of oil and natural gas derivatives - Non-current Assets	-	31	-	31
Fair value of oil and natural gas derivatives - Current Liabilities	-	-	-	-
Fair value of oil and natural gas derivatives - Non-current Liabilities	-	(2,786)	-	(2,786)
Total	$ -	$ 5,782	$ -	$ 5,782

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, 2019:

	December 31, 2019		
Fair Value of Oil and Natural Gas Derivatives (in thousands)	**Gross Amount**	**Amount Offset**	**As Presented**
Fair value of oil and natural gas derivatives - Current Assets	$ 9,401	$ (864)	$ 8,537
Fair value of oil and natural gas derivatives - Non-current Assets	847	(816)	31
Fair value of oil and natural gas derivatives - Current Liabilities	(864)	864	-
Fair value of oil and natural gas derivatives - Non-current Liabilities	(3,602)	816	(2,786)
Total	$ 5,782	$ -	$ 5,782

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, 2019 (in thousands):

		Payment due by Period					
	Note	Total	2020	2021	2022	2023	2024 and After
Debt	5	$ 105,869	$ -	$ 12,969	$ -	$ -	$ 92,900
Office space leases	11	2,353	$ 1,540	$ 813	$ -	$ -	$ -
Operations contracts		2,491	$ 2,491	$ -	$ -	$ -	$ -
Total contractual obligations (1)		$ 110,713	$ 4,031	$ 13,782	$ -	$ -	$ 92,900

(1) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $4.2 million as of December 31, 2019. 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, 2019, and 2018 was approximately $1.7 million and $1.6 million, respectively.

NOTE 11—Leases

We adopted ASU 2016-02, Leases, on January 1, 2019, and we elected the transition relief package of practical expedients. We determine if an arrangement is or contains a lease at inception. Leases with an initial term of 12 months or less are not recorded on our Consolidated Balance Sheets. We lease our corporate office building in Houston, Texas. We recognize lease expense for this lease on a straight-line basis over the lease term. This operating lease is included in furniture, fixtures and equipment and other capital assets, accrued liabilities and other non-current liabilities on our Consolidated Balance Sheets. The operating lease asset and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term. As this lease did not provide an implicit rate, we used a collateralized incremental borrowing rate based on the information available at commencement date, including lease term, in determining the present value of future payments. The operating lease asset includes any lease payments made but excludes annual operating charges. Operating lease expense is recognized on a straight-line basis over the lease term and reported in general and administrative operating expense on our Consolidated Statements of Operations. We have also entered into leases for certain vehicles and other equipment which are immaterial to our financial statements and have therefore not been recorded on our Consolidated Balance Sheets.

The lease cost components for the year ended December 31, 2019 are classified as follows:

(in thousands)	Year Ended December 31, 2019	Consolidated Statements of Operations Classification
Building lease cost	$ 1,540	General and administrative expense
Variable lease cost (1)	118	General and administrative expense
	$ 1,658	

(1) Includes building operating expenses.

The following are additional details related to our lease portfolio as of December 31, 2019:

(in thousands)	December 31, 2019	Consolidated Balance Sheets Classification
Lease asset, gross	$ 2,922	Furniture, fixtures and equipment and other capital assets
Accumulated depreciation	(1,252)	Accumulated depletion, depreciation and amortization
Lease asset, net	$ 1,670	
Current lease liability	$ 1,414	Accrued liabilities
Non-current lease liability	800	Other non-current liabilities
Total lease liabilities	$ 2,214	

The following table presents operating lease liability maturities as of December 31, 2019:

(in thousands)	December 31, 2019
2020	1,540
2021	813
2022	-
2023	-
Thereafter	-
Total lease payments	$ 2,353
Less imputed interest	$ 139
Present value of lease liabilities	$ 2,214

As of December 31, 2019, our office building operating lease has a weighted-average remaining lease term of 1.3 years and a weighted-average discount rate of 8.0 percent. Cash paid for amounts included in the measurement of operating lease liabilities was $1.6 million for the year ended December 31, 2019.

NOTE 12—Dispositions and Acquisitions

On March 1, 2019, the Company closed on the sale of working interests in certain non-core Haynesville Shale Trend oil and gas leases and related facilities in Caddo Parish, Louisiana for total consideration of $1.3 million, 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 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.

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY
SUPPLEMENTAL INFORMATION
(Unaudited)

NOTE 13—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 35 years of experience in the oil and natural gas industry, including over 30 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 a participant in professional industry groups and has been a member of the Society of Petroleum Engineers for over 35 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, 2019 and 2018 have been independently prepared by NSAI and RSC. NSAI prepared the estimates on all our proved reserves as of December 31, 2019 and 2018 on our properties other than in the TMS. RSC prepared the estimate of proved reserves as of December 31, 2019 and 2018 for our TMS properties. Copies of the summary reserve reports of NSAI and RSC for 2019 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 2019. For oil volumes, the average price of $55.69 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For natural gas volumes, the average price of $2.58 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, 2019 and 2018 (in thousands):

	Year Ended December 31, 2019	Year Ended December 31, 2018
Proved properties	$ 302,859	$ 206,097
Unproved properties	123	180
	302,982	206,277
Less: accumulated depreciation, depletion and amortization	(91,958)	(41,886)
Net oil and natural gas properties	$ 211,024	$ 164,391

We did not have any capitalized exploratory well costs that were pending the determination of proved reserves as of December 31, 2019 and 2018, respectively.

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, 2019	Year Ended December 31, 2018
Property Acquisition		
Unproved	$ 269	$ 178
Proved	-	-
Exploration	-	-
Development (1)	97,972	106,583
Total (2)	$ 98,241	$ 106,761

(1) Includes asset retirement costs of $0.1 million in 2019 and less than $0.1 million in 2018.
(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, 2019, 2018 and 2017 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)		
	2019	2018	2017	2019	2018	2017
Net proved reserves at beginning of period	470,937	415,224	286,038	1,441	2,130	2,815
Revisions of previous estimates (1)	(132,005)	(16,993)	106,639	(166)	(388)	(381)
Extensions, discoveries and improved recovery (2)	218,015	100,499	32,871	-	-	-
Purchases of minerals in place	-	-	-	-	-	-
Sales of minerals in place	(169)	(3,349)	-	-	(84)	-
Production	(46,712)	(24,444)	(10,324)	(171)	(217)	(304)
Net proved reserves at end of period	510,066	470,937	415,224	1,104	1,441	2,130
Net proved developed reserves:						
Beginning of period	92,118	52,861	21,872	1,441	2,130	2,815
End of period	138,607	92,118	52,861	1,104	1,441	2,130
Net proved undeveloped reserves:						
Beginning of period	378,819	362,363	264,166	-	-	-
End of period	371,459	378,819	362,363	-	-	-

	Natural Gas Equivalents (Mmcfe)		
	2019	**2018**	**2017**
Net proved reserves at beginning of period	479,583	428,002	302,927
Revisions of previous estimates (1)	(133,001)	(19,320)	104,354
Extensions, discoveries and improved recovery (2)	218,016	100,499	32,871
Purchases of minerals in place	-	-	-
Sales of minerals in place (3)	(169)	(3,852)	-
Production	(47,738)	(25,746)	(12,150)
Net proved reserves at end of period	516,691	479,583	428,002
Net proved developed reserves:			
Beginning of period	100,764	65,639	44,432
End of period	145,232	100,764	65,639
Net proved undeveloped reserves:			
Beginning of period	378,819	362,363	258,495
End of period	371,459	378,819	362,363

(1) Revisions of previous estimates in 2019 were negative, primarily due to commodity prices. Revisions of previous estimates in 2018 were negative, primarily due to increases in our operating expenditures and other tax rates. Revisions of previous estimates in 2017 were positive, primarily 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 2019, we sold approximately 55 Mmcfe and 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):

	2019	**2018**	**2017**
Future revenues	$ 1,272,504	$ 1,494,557	$ 1,260,490
Future lease operating expenses and production taxes	(377,851)	(410,957)	(430,048)
Future development costs (1)	(338,116)	(349,552)	(329,938)
Future income tax expense	(13,945)	(56,784)	(17,113)
Future net cash flows	542,592	677,264	483,391
10% annual discount for estimated timing of cash flows	(248,269)	(279,679)	(223,081)
Standardized measure of discounted future net cash flows	$ 294,323	$ 397,585	$ 260,310
Index price used to calculate reserves (2)			
Natural gas (per Mcf)	$ 2.58	$ 3.10	$ 2.98
Oil (per Bbl)	$ 55.69	$ 65.56	$ 51.34

(1) Includes cumulative asset retirement obligations of $7.4 million and $7.3 million in 2019 and 2018, 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.

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,		
	2019	2018	2017
Balance, beginning of year	$ 397,585	$ 260,310	$ 56,922
Net changes in prices and production costs related to future production	(146,806)	95,927	113,319
Sales and transfers of oil and natural gas produced, net of production costs	(82,706)	(63,846)	(32,012)
Net change due to revisions in quantity estimates	(130,244)	(25,595)	107,499
Net change due to extensions, discoveries and improved recovery	101,012	129,207	8,970
Net change due to purchases and sales of minerals in place	10	(3,382)	-
Changes in future development costs	125,172	(4,608)	(59,560)
Previously estimated development cost incurred in period	31,340	7,923	8,114
Net change in income taxes	17,555	(16,336)	(3,686)
Accretion of discount	41,777	26,416	5,709
Change in production rates (timing) and other	(60,372)	(8,431)	55,035
Net increase (decrease) in standardized measures	(103,262)	137,275	203,388
Balance, end of year	$ 294,323	$ 397,585	$ 260,310

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, 2019, 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.

PART III

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

Our executive officers and directors and their ages and positions as of March 5, 2020, are as follows:

Name	Age	Position
Walter G. “Gil” Goodrich	61	Chairman of the Board of Directors, Chief Executive Officer and Director
Robert C. Turnham, Jr.	62	President, Chief Operating Officer and Director
Mark E. Ferchau	65	Executive Vice President
Michael J. Killelea	57	Executive Vice President, General Counsel and Corporate Secretary
Robert T. Barker	69	Senior Vice President, Controller, Chief Accounting Officer and Chief Financial Officer
Ronald F. Coleman	65	Director
K. Adam Leight	63	Director
Timothy D. Leuliette	70	Director
Jeffrey S. Serota	54	Director
Edward J. Sondey	54	Director
Thomas M. Souers	66	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.

Ronald F. Coleman is an energy executive with over 37 years of international and domestic oilfield services operations experience. 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.

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, its 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.

Jeffrey S. Serota serves as Vice Chairman and Chief Investment Officer of Corbel Capital Partners, an independent investment firm that makes non-control investments in debt or equity securities in lower middle-market businesses. Mr. Serota has over 30 years of experience as a principal investor, financial services professional and operating executive. Independent of his responsibilities at Corbel, Mr. Serota currently serves as the Chairman of Great Elm Capital Group and as a Director of Maverick Natural Resources. Prior to joining Corbel, Mr. Serota served as a Senior Partner with Ares Management in Los Angeles from 1997 to 2012 and as a Senior Advisor to Ares in 2013. While at Ares, Mr. Serota was a member of the Investment Committee for all private equity related transactions. He has led transactions (including sourcing, due diligence, financing, consummating, monitoring and exiting) of a variety of sizes and in numerous industries including industrials, energy, chemicals, manufacturing and business services. As part of his role as Senior Partner at Ares, Mr. Serota acted as an interim CEO for certain portfolio company investments of Ares, led fundraising efforts for private equity investment funds, and participated in numerous private and public companies as a member of the boards of directors. Prior to joining Ares, Mr. Serota worked at Bear Stearns, Dabney/Resnick, Inc. and Salomon Brothers Inc. Mr. Serota received a B.S. in Economics from the Wharton School at the University of Pennsylvania, and an M.B.A. from the Anderson School of Management at the University of California at Los Angeles. He was elected to the Company's Board of Directors in 2019.

Edward J. Sondey serves as Senior Managing Director of Private Equity at LS Power Group where he is responsible for the firm's E&P and midstream investments. Mr. Sondey joined LS Power in 2011 and has over twenty-five years of experience in the energy industry. Prior to joining LS Power, Mr. Sondey served as Managing Director in the BofA Merrill Lynch global energy & power investment banking group from 2005 to 2011. He was head of competitive generation, and advised a broad range of industrial and financial clients on the execution of M&A, capital markets and structured commodity transactions. Prior to BofA Merrill, Mr. Sondey was Vice President, Finance for PSEG Power from 2000 to 2005 where he led strategic and finance activities and executed several asset M&A and development transactions. Mr. Sondey started his career as an early member of J. Makowski Associates, a Warburg Pincus portfolio company. Mr. Sondey received a BA degree from Princeton University. He was elected to the Company's Board of Directors in 2019.

Thomas M. Souers served as a 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 the 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 2020 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 2020 annual meeting of stockholders to be filed within 120 days from December 31, 2019. 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 2020 Annual Meeting of Stockholders to be filed within 120 days from December 31, 2019.

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 2020 Annual Meeting of Stockholders to be filed within 120 days from December 31, 2019.

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 2020 Annual Meeting of Stockholders to be filed within 120 days from December 31, 2019.

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 2020 Annual Meeting of Stockholders to be filed within 120 days from December 31, 2019.

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 47.

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

3.1	Third Amended and Restated Certificate of Incorporation of Goodrich Petroleum Corporation, dated August 16, 2019, (Incorporated by reference to Exhibit 3.1 of the Company's Registration Statement on Form 8-K (File No. 333-12719) filed on August 21, 2019).
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 May 31, 2019, 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 2021 (Incorporated by reference to Exhibit 4.1 of the Company's Form 8-K (File No. 001-12719) filed on June 3, 2019).
4.3	Registration Rights Agreement, dated as of May 31, 2019, by and among Goodrich Petroleum Corporation and the Holders party thereto, relating to the New 2L Notes (Incorporated by reference to Exhibit 4.2 of the Company's Form 8-K (File No. 001-12719) filed on June 3, 2019).
4.4*	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934.
10.1*	Form Agreement of the Restricted Stock and Performance Stock Unit awards dated December 14, 2017 and December 10, 2019 under the 2016 Long Term Incentive Plan.
10.2	Second Amended and Restated Senior Secured Revolving Credit Agreement, dated as of May 14, 2019, among Goodrich Petroleum Corporation, as Parent Guarantor, Goodrich Petroleum Company, L.L.C., as Borrower, SunTrust Bank, as Administrative Agent, and the Lenders party thereto (Incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on May 14, 2019).
10.3	Note Purchase Agreement, dated as of May 14, 2019, among Goodrich Petroleum Corporation, Goodrich Petroleum Company, L.L.C., as subsidiary guarantor and certain funds and accounts managed by Franklin Advisers, Inc. as investment manager (Incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q (File No. 001-12719) filed on May 14, 2019.

10.4	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).
10.5	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).
10.6	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).
10.7†	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).
10.8†	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).
10.9†	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).
10.10†	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).
10.11†	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).
10.12†	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).
10.13†	Amendment and Restatement of Severance Agreement between the Company and Walter G. Goodrich dated August 22, 2018 (Incorporated by reference to Exhibit 10.1 of the Company's Form 8-K (File No. 001-12719) filed on August 23, 2018).
10.14†	Amendment and Restatement of Severance Agreement between the Company and Robert C. Turnham, Jr. dated August 22, 2018 (Incorporated by reference to Exhibit 10.1 of the Company's Form 8-K (File No. 001-12719) filed on August 23, 2018).
10.15†	Amendment and Restatement of Severance Agreement between the Company and Mark E. Ferchau dated August 22, 2018(Incorporated by reference to Exhibit 10.1 of the Company's Form 8-K (File No. 001-12719) filed on August 23, 2018).

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.
24.1*	Power of Attorney (included on the signature page hereto)
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

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* 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, 2020.

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, 2020.

Signature	Title
/s/ WALTER G. GOODRICH **Walter G. Goodrich**	Chairman, Chief Executive Officer and Director (Principal Executive Officer)
/s/ ROBERT C. TURNHAM, JR. **Robert C. Turnham, Jr.**	President, Chief Operating Officer and Director
/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/ JEFFREY SEROTA **Jeffrey Serota**	Director
/s/ EDWARD SONDEY **Edward Sondey**	Director
/s/ TOM SOUERS **Tom Souers**	Director

DESCRIPTION OF THE REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

Goodrich Petroleum Corporation ("we," "our," "us," or the "Company") has one class of securities registered under Section 12 of the Securities Exchange Act of 1934, as amended, our common stock, $0.01 par value per share (our "Common Stock"). The following summary includes a brief description of our Common Stock as well as certain related information. For the complete terms of our Common Stock and preferred stock, $1.00 par value per share ("Preferred Stock"), please refer to our Third Amended and Restated Certificate of Incorporation, as amended (our "Certificate of Incorporation") and our Second Amended and Restated Bylaws (our "Bylaws"). The Delaware General Corporation Law ("DGCL") may also affect the terms of these securities.

Authorized Capital Stock

Our authorized capital stock consists of

- 75,000,000 shares of Common Stock; and

- 10,000,000 shares of Preferred Stock.

Common Stock

Dividends. Subject to preferential dividend rights of any other class or series of stock, the holders of shares of our Common Stock are entitled to receive dividends, including dividends of our stock, if, as and when declared by our board of directors (the "Board"), subject to any limitations applicable by law and to the rights of the holders, if any, of our Preferred Stock.

Liquidation. In the event we are liquidated, dissolved or our affairs are wound up, after we pay or make adequate provision for all of our known debts and liabilities and pay or set aside for payment any preferential amount due to the holders of any other class or series of stock, each holder of our Common Stock will be entitled to share ratably in any or all assets that remain to be paid or distributed.

Voting Rights. Subject to any special voting rights of any series of Preferred Stock, each holder of our Common Stock is entitled to one vote for each share registered in the holder's name on all matters which the stockholders are entitled to vote, and the holders of our Common Stock shall have the exclusive right to vote for the election of Directors and on all other matters upon which the stockholders are entitled to vote, and, subject to the Series Terms (as defined in the Certificate of Incorporation) of any one or more series of Preferred Stock, the holders of any series of Preferred Stock shall not be entitled to vote at or receive notice of any meeting of stockholders; *provided*, *however*, that except as otherwise required by law, each holder of our Common Stock is not entitled to vote on any amendment to the Certificate of Incorporation (including any certificates of designation relating to any series of Preferred Stock) that relates solely to the terms of one or more outstanding series of Preferred Stock, if the holders of such affected series of Preferred Stock are entitled, either separately or together as a class with the holders of one or more other such series, to vote thereon pursuant to the Certificate of Incorporation (including any certificates of designation relating to any series of Preferred Stock). Holders of our Common Stock vote together as a single class. There is no cumulative voting in the election of our directors, which means that, subject to any rights to elect directors that are granted to the holders of any class or series of Preferred Stock, a majority of the votes cast at a meeting of stockholders at which a quorum is present is sufficient to elect a director.

Preemptive Rights. Any issuance of Common Stock, or other capital stock, and rights, convertible securities, options or warrants to purchase Common Stock or other capital stock ("New Securities") by the Company or any of its subsidiaries, other than an issuance of Exempt Securities (as defined below), shall be subject to a preemptive right, granted by the Company to each stockholder that, together with its affiliates, holds of record at least 10% of the Common Stock then outstanding (each, a "Qualified Shareholder"), to purchase a pro rata share of any and all issuances, sales or distributions of New Securities proposed to be made by the Company or any of its subsidiaries, subject to certain requirements.

Notwithstanding the foregoing, Qualified Shareholders shall not have the right to participate in the issuance of any New Securities which are otherwise authorized to be issued in accordance with the Certificate of Incorporation (i) if such New Securities were issued as consideration in any merger, consolidation or combination with or acquisition of securities or assets of another person in exchange for New Securities, (ii) if made upon conversion or exercise of any rights, convertible securities, options or warrants to purchase Common Stock or other capital stock of the Company, (iii) if made by any subsidiary of the Company to the Company or any of its direct or indirect wholly owned subsidiaries, (iv) if made as securities which are the subject of an effective registration statement, (v) if made to directors, officers, employees or consultants as compensation pursuant to any employee incentive plans or (vi) if such New Securities were issued in connection with the Debtors' First Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code, dated August 18, 2016 (together with all exhibits and schedules thereto) filed by the Company and Goodrich Petroleum Company, L.L.C., our wholly owned subsidiary, with the United States Bankruptcy Court for the Southern District of Texas (the New Securities described in the foregoing clauses (i) through (vi), "Exempt Securities").

Other Rights and Restrictions. Subject to the preferential rights of any other class or series of stock, all shares of our Common Stock have equal dividend, distribution, liquidation and other rights, and have no preference, appraisal or exchange rights, except for any appraisal rights provided by Delaware law. Furthermore, holders of our Common Stock have no conversion, or sinking fund or redemption rights. Our Certificate of Incorporation and Bylaws do not restrict the ability of a holder of our Common Stock to transfer the holder's shares of our Common Stock.

The rights, powers, preferences and privileges of holders of our Common Stock are subject to, and may be adversely affected by, the rights of holders of shares of our outstanding Preferred Stock and of any series of Preferred Stock which we may designate and issue in the future.

Preferred Stock

Under our Certificate of Incorporation, the Board has the authority, subject to any limitations prescribed by law and without further stockholder approval, to issue from time to time up to 10,000,000 shares of Preferred Stock.

The Preferred Stock is issuable in one or more series, each with such powers, voting powers, designations, preferences, rights, qualifications, limitations and restrictions as the Board, or any committee of the Board to which such responsibility is specifically and lawfully delegated, may determine in resolutions providing for their issuance.

The issuance of Preferred Stock may have the effect of delaying, deferring or preventing a change in control of us without further action by the stockholders and may adversely affect the voting and other rights of the holders of our Common Stock. The issuance of Preferred Stock with voting and conversion rights may adversely affect the voting power of the holders of Common Stock, including loss of voting control to others.

Pursuant to our Certificate of Incorporation we are authorized to issue "blank check" Preferred Stock, which may be issued from time to time in one or more series upon authorization by the Board. The Board, or any committee of the Board to which such responsibility is specifically and lawfully delegated, without further approval of the stockholders, is authorized to fix the dividend rights and terms, voting rights, conversion rights, redemption rights and terms, sinking fund provisions, liquidation preferences, restrictions upon the creation of indebtedness or issuance of additional Preferred Stock, and any other rights, preferences, privileges and restrictions applicable to each series of the Preferred Stock.

The issuance of Preferred Stock, while providing flexibility in connection with possible acquisitions and other corporate purposes could, among other things, adversely affect the voting power or rights of the holders of our Common Stock and, under certain circumstances, make it more difficult for a third party to gain control of us, discourage bids for our Common Stock at a premium or otherwise adversely affect the market price of the Common Stock.

The summaries above of selected provisions of our Common Stock and Preferred Stock are qualified entirely by the provisions of our Certificate of Incorporation, our Bylaws, and our debt agreements, all of which are included or incorporated by reference as exhibits to the Annual Report on Form 10-K of which this Exhibit 4.4 is a part.

Anti-Takeover Effects of Delaware Law, Our Certificate of Incorporation and Our Bylaws

Some provisions of Delaware law, our Certificate of Incorporation and our Bylaws contain provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

Section 203 of the DGCL prohibits a Delaware corporation from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the transaction is approved by the board of directors before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or
- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

An interested stockholder is defined as a person who, together with any affiliates or associates of such person, beneficially owns, directly or indirectly, 15% or more of the outstanding voting shares of a Delaware corporation. The term “business combination” is broadly defined to include a broad array of transactions, including mergers, consolidations, sales or other dispositions of assets having a total value in excess of 10% of the consolidated assets of the corporation or all of the outstanding stock of the corporation, and some other transactions that would increase the interested stockholder’s proportionate share ownership in the corporation.

Our Certificate of Incorporation and Our Bylaws

Provisions of our Certificate of Incorporation and our Bylaws may delay or discourage transactions involving an actual or potential change in control or change in our management, including transactions in which stockholders might otherwise receive a premium for their shares, or transactions that our stockholders might otherwise deem to be in their best interests. Therefore, these provisions could adversely affect the price of our Common Stock.

Among other things, our Certificate of Incorporation and Bylaws:

- provide that for so long as Franklin Advisers, Inc. (“Franklin”) shall beneficially own greater than 10% of the total outstanding Common Stock of the Company, Franklin shall be entitled to designate three nominees for election to the Board, with such designation right not being subject to reinstatement, despite any later increase in Franklin’s Common Stock ownership.
- provide that all vacancies, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of a series of Preferred Stock or certain board designation rights, be filled by a majority of directors then in office, even if less than a quorum, or by the sole remaining director, and any director so chosen shall hold office until the next annual meeting for the election of directors and until his or her successor shall be duly elected and qualified.
- provide that directors may be removed be removed from office, either with or without cause, by the affirmative vote of the holders of a majority of the shares then entitled to vote at an election of directors acting at a meeting of the stockholders in accordance with the DGCL, our Certificate of Incorporation and our Bylaws;
- provide that special meetings of our stockholders may only be called by our Chairman of the Board, Vice Chairman, Chief Executive Officer or by a majority of the directors then in office;
- authorize the Board to adopt resolutions providing for the issuance of undesignated Preferred Stock. This ability makes it possible for the Board to issue, without stockholder approval, Preferred Stock with voting or other rights or preferences that could impede the success of any attempt to change control of us;
- provide that the authorized number of directors may be changed only by the Board; and
- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, for a proposal to be timely submitted for consideration at an annual meeting, notice must be delivered to our secretary not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Generally, for a proposal to be timely submitted for consideration at a special meeting at which directors are to be elected, notice must be delivered to our secretary not earlier than the date on which public announcement of the date of such meeting is first made by the Company and not later than the close of business on the 15th day following the date of first public announcement. Our Bylaws specify the requirements as to form and content of all stockholders’ notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting.

Amendment of the Bylaws

Under the DGCL, the power to adopt, amend or repeal bylaws is conferred upon the stockholders. A corporation may, however, in its certificate of incorporation also confer upon the board of directors the power to adopt, amend or repeal its bylaws. The Certificate of Incorporation and the Bylaws grant to the Board the power to adopt, amend, restate or repeal the Bylaws, provided that no bylaw adopted by the stockholders may be amended, repealed or readopted by the Board if such bylaw so provides. The stockholders may adopt, amend, restate or repeal the Bylaws but only by the affirmative vote of the holders of at least 66 2/3% of our then outstanding voting stock.

No Cumulative Voting

Our stockholders do not have the right to cumulate votes, as discussed further under "—Common Stock—Voting Rights."

Exclusive Forum

Our Certificate of Incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware shall, to the fullest extent permitted by law, be the sole and exclusive forum for (1) any derivative action or proceeding brought in the name or right of us or on our behalf, (2) any action asserting a claim for breach of a fiduciary duty owed by any of our directors, officers, employees, stockholders or other agents to us or our stockholders, (3) any action arising or asserting a claim arising pursuant to any provision of the DGCL or any provision of the Certificate of Incorporation or the Bylaws or as to which the DGCL confers jurisdiction on the Court of Chancery of the State of Delaware or (4) any action asserting a claim governed by the internal affairs doctrine, including, without limitation, any action to interpret, apply, enforce or determine the validity of the Certificate of Incorporation or the Bylaws. Any person or entity purchasing or otherwise acquiring any interest in shares of our stock shall be deemed to have notice of and consented to the foregoing forum selection provisions.

Limitations of Liability and Indemnification Matters

Our Certificate of Incorporation limits the liability of our directors for monetary damages for breach of their fiduciary duty as directors, except for liability that cannot be eliminated under the DGCL. Delaware law provides that directors of a company will not be personally liable for monetary damages for breach of their fiduciary duty as directors, except for liabilities:

- for any breach of their duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;
- for unlawful payment of dividend or unlawful stock repurchase or redemption, as provided under Section 174 of the DGCL; or
- for any transaction from which the director derived an improper personal benefit.

Any amendment, repeal or modification of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment, repeal or modification.

Our Certificate of Incorporation also provides that we will indemnify our directors and officers to the fullest extent permitted by Delaware law. If Delaware law is amended to authorize corporate action further eliminating or limiting the personal liability of a director, then the liability of our directors will be eliminated or limited to the fullest extent permitted by Delaware law, as so amended. Our Certificate of Incorporation also permits us to purchase insurance on behalf of any officer, director, employee or other agent for any liability arising out of that person's actions as our officer, director, employee or agent, regardless of whether Delaware law would permit indemnification. We have entered into indemnification agreements with each of our directors and officers. These agreements require us to indemnify these individuals to the fullest extent permitted under Delaware law against liability that may arise by reason of their service to us, and to advance expenses incurred as a result of any proceeding against them as to which they could be indemnified. We believe that the limitation of liability provision in Certificate of Incorporation and the indemnification agreements facilitates our ability to continue to attract and retain qualified individuals to serve as directors and officers.

The limitation of liability and indemnification provisions in our Certificate of Incorporation and Bylaws may discourage stockholders from bringing a lawsuit against directors for breach of their fiduciary duties. They may also reduce the likelihood of derivative litigation against directors and officers, even though an action, if successful, might benefit us and our stockholders. A stockholder's investment may be harmed to the extent we pay the costs of settlement and damage awards against directors and officers pursuant to these indemnification provisions. Insofar as indemnification for liabilities arising under the Securities Act of 1933 (the "Securities Act") may be permitted to our directors, officers and controlling persons pursuant to the foregoing provisions, or otherwise, we have been advised that, in the opinion of the SEC, such indemnification is against public policy as expressed in the Securities Act, and is, therefore, unenforceable. There is no pending litigation or proceeding naming any of our directors or officers as to which indemnification is being sought, nor are we aware of any pending or threatened litigation that may result in claims for indemnification by any director or officer.

Transfer Agent and Registrar

The transfer agent and registrar for our Common Stock is American Stock Transfer & Trust Company.

Listing

Our Common Stock is quoted on the NYSE American LLC under the symbol "GDP."

GOODRICH PETROLEUM CORPORATION
2016 LONG TERM INCENTIVE PLAN

Grant of Shares

Grantee:

Grant Date:

1. **Grant of Shares**. Goodrich Petroleum Corporation (the "Company") hereby grants to you XXX Shares under the Goodrich Petroleum Corporation 2016 Long Term Incentive Plan (the "Plan") on the terms and conditions set forth herein and in the Plan, which is incorporated herein by reference as a part of this Agreement. In the event of any conflict between the terms of this Agreement and the Plan, the Plan shall control. Capitalized terms used in this Agreement but not defined herein shall have the meanings ascribed to such terms in the Plan, unless the context requires otherwise. Upon vesting pursuant to Sections 2 or 3, you will be entitled to receive the vested amount of the Phantom Shares in shares of Common Stock of the Company.

2. **Regular Vesting**. The Shares granted hereunder are comprised of (i) XXX performance-based Phantom Shares (the "Performance Vesting Phantom Shares") which shall vest, or be forfeited, on XXX with a potential award ranging from no shares up to shares in accordance with the attached Performance-Based Payment Schedule (unless they vest prior to such date in accordance with Paragraph 3 below), and (ii) XXX Phantom Shares (the "Time Vesting Phantom Shares") which shall vest on the anniversaries of XXX as follows:

Vesting Date	Cumulative Vested Percentage
1st Anniversary	33⅓%
2nd Anniversary	66⅔%
3rd Anniversary	100%

Vesting with respect to a fractional share shall be rounded up to the next whole share. The Performance Vesting Phantom Shares and the Time Vesting Phantom Shares are referred to, collectively, in this Agreement as the "Phantom Awards."

3. **Events Occurring Prior to Regular Vesting**.

(a) **Death or Disability**. If, prior to becoming fully vested in the Performance Vesting Phantom Shares or Time Vesting Phantom Shares hereby granted, you cease to be an employee of the Company as a result of your death or a disability that entitles you to benefits under the Company's long-term disability plan, the Time Vesting Phantom Shares then held by you will automatically become fully vested upon such termination and the Performance Vesting Phantom Shares then held by you will automatically become vested at 100% of Target Payment (as such term is used in the attached Performance-Based Payment Schedule) upon such termination.

(b) **Other Terminations**. If you terminate from the Company for any reason other than as provided in Paragraph 3(a), all unvested Phantom Awards then held by you automatically shall be forfeited without payment upon such termination.

(c) **Change of Control**. All outstanding Phantom Awards held by you at the time of a Change of Control will automatically become fully vested upon the Change of Control. With respect to the Performance Vesting Phantom Shares described in Paragraph 2 above, the calculations under the Performance-Based Payment Schedule attached hereto shall be made at the time of such Change of Control if prior to December 10, 2022.

For purposes of this Agreement, your employment with a parent or Subsidiary of the Company shall be deemed to be employment with the Company.

4. **Stock Certificates**. Upon vesting pursuant to Section 2 or Sections 3(a) or (c), the Company shall cause a stock certificate to be issued in your name for the shares of Common Stock that become vested. Settlement of Phantom Awards that vest pursuant to this Agreement will occur no later than 60 days following the applicable vesting event.

5. **Limitations Upon Transfer**. The Phantom Awards and all other rights under this Agreement shall belong to you alone and may not be transferred, assigned, pledged, or hypothecated by you in any way (whether by operation of law or otherwise), other than by will or the laws of descent and distribution and shall not be subject to execution, attachment, or similar process. Upon any attempt by you to transfer, assign, pledge, hypothecate, or otherwise dispose of such rights contrary to the provisions in this Agreement or the Plan, or upon the levy of any attachment or similar process upon such rights, such rights shall immediately become null and void.

6. **Restrictions**. By accepting this grant, you agree that any shares of Common Stock which you may acquire upon the vesting and payment of this award, if any, will not be sold or otherwise disposed of in any manner which would constitute a violation of any applicable federal or state securities laws, other applicable law or Company policies as determined by Company on advice of counsel chosen by the Company in its sole discretion. Notwithstanding any provision of this Agreement to the contrary, the issuance of Common Stock, if any, will be subject to compliance with all applicable requirements of federal, state, or foreign law with respect to such securities and with the requirements of any stock exchange or market system upon which the shares of Common Stock may then be listed. The Company may require you, as a condition of receiving the Common Stock, to give written assurances in substance and form satisfactory to the Company and its counsel to the effect that you are acquiring the Common Stock underlying the Phantom Awards for your own account for investment and not with any present intention of selling or otherwise distributing the same, and to such other effects as the Company deems necessary or appropriate to comply with federal and any applicable state and foreign securities laws. The Company intends to register the shares under the Plan on Form S-8 filed with the Securities and Exchange Commission. No shares will be issued hereunder if such issuance would constitute a violation of any applicable federal, state, or foreign securities laws or other law or regulations or the requirements of any stock exchange or market system upon which the shares may then be listed. In addition, shares will not be issued hereunder unless (a) a registration statement under the Securities Act of 1933, as amended (the "Securities Act") is at the time of issuance in effect with respect to the shares issued or (b) in the opinion of legal counsel to the Company, the shares issued may be issued in accordance with the terms of an applicable exemption from the registration requirements of the Securities Act. The inability of the Company to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Company's legal counsel to be necessary to the lawful issuance and sale of any shares subject to this Agreement will relieve the Company of any liability in respect of the failure to issue such shares as to which such requisite authority has not been obtained.

7. **Withholding of Tax**. To the extent that the grant, vesting or settlement of Phantom Awards results in the receipt of compensation by you with respect to which the Company or an affiliate has a tax withholding obligation pursuant to applicable law, unless other arrangements have been made by you that are acceptable to the Company or such affiliate, you shall deliver to the Company or the affiliate such amount of money as the Company or the affiliate may require or determine to be advisable. No issuance of a share of stock shall be made pursuant to this Agreement until you have paid or made arrangements approved by the Company or the affiliate to satisfy in full the applicable tax withholding requirements of the Company or affiliate.

8. **Phantom Dividends**. If during the period the Phantom Awards are held by you the Company pays a dividend on its Common Stock, you will be credited with additional Phantom Awards hereunder equal to the Fair Market Value of such dividends. Such additional Phantom Awards shall be subject to the same vesting provisions (including performance vesting provisions) and other provisions of this Agreement as if part of the tandem Phantom Award to which the phantom dividend relates and will be paid to you in Common Stock at the same time that the Phantom Awards associated with such phantom dividends are settled pursuant to this Agreement. For purposes of phantom dividends calculated on Performance Vesting Phantom Shares, such phantom dividends will be calculated on a number of Phantom Shares equal to 100% of the Target Payment (as such term is used in the attached Performance-Based Payment Schedule).

9. **Consent to Electronic Delivery; Electronic Signature**. In lieu of receiving documents in paper format, you agree, to the fullest extent permitted by law, to accept electronic delivery of any documents that the Company may be required to deliver (including, without limitation, prospectuses, prospectus supplements, grant or award notifications and agreements, account statements, annual and quarterly reports, and all other forms of communications) in connection with this and any other award made or offered by the Company. Electronic delivery may be via an electronic mail system of the Company or by reference to a location on a Company intranet to which you have access. You hereby consent to any and all procedures the Company has established or may establish for an electronic signature system for delivery and acceptance of any such documents that the Company may be required to deliver, and the Company agrees that your electronic signature is the same as, and shall have the same force and effect as, your manual signature.

10. **Binding Effect**. This Agreement shall be binding upon and inure to the benefit of any successor or successors of the Company and upon any person lawfully claiming under you.

11. **Entire Agreement.** This Agreement constitutes the entire agreement of the parties with regard to the subject matter hereof, and contains all the covenants, promises, representations, warranties and agreements between the parties with respect to the Phantom Award granted hereby. Without limiting the scope of the preceding sentence, all prior understandings and agreements, if any, among the parties hereto relating to the subject matter hereof are hereby null and void and of no further force and effect. Any modification of this Agreement shall be effective only if it is in writing and signed by both you and an authorized officer of the Company.

12. **Independent Legal and Tax Advice**. You have been advised, and you hereby acknowledge that you have been advised, to obtain independent legal and tax advice regarding this grant of a Phantom Award and the issues of Common Stock and eventual disposition of such Common Stock. The Board and the Company do not guarantee Common Stock potentially issued in connection herewith from loss or depreciation.

13. **Governing Law**. This grant shall be governed by, and construed in accordance with, the laws of the State of Texas, without regard to conflicts of laws principles thereof.

Please return this Agreement signed to the Company. The enclosed copy is for your records.

Agreed and accepted by Grantee **Goodrich Petroleum Corporation**

_________________________ By: Leslee M. Ranly

Name: Leslee M. Ranly Title: VP-Human Resources and Administration

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements No. 333-214080 and No. 333-221429 on Form S-8, the Registration Statement No. 333-233581 on Form S-1 and Registration Statement No. 333-217675 on Form S-3 of Goodrich Petroleum Corporation of our report dated March 5, 2020, relating to the consolidated financial statements of Goodrich Petroleum Corporation, appearing in this Annual Report (Form 10-K) for the year ended December 31, 2019.

/s/ Moss Adams LLP

Houston, Texas
March 5, 2020

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We consent to the incorporation by reference in the Registration Statements No. 333-233581 on Form S-1, No. 333-221429 on Form S-8, No. 333-217675 on Form S-3, and No. 333-214080 on Form S-8, of Goodrich Petroleum Corporation of information relating to Goodrich Petroleum Corporation's estimated proved reserves as set forth under the captions "Part I, Items 1 and 2. Business and Properties – Oil and Natural Gas Reserves" in Goodrich Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2019 and to the inclusion of our report dated February 5, 2020 in Goodrich Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2019.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
March 5, 2020

Exhibit 23.3

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA STREET SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We consent to the incorporation by reference in the Registration Statements:

1. Registration Statement (Form S-1 333-233581) pertaining to the shares of common stock issuable upon conversion of the 13.50% Convertible Second Lien Senior Secured notes due 2021,
2. Registration Statement (Form S-8 333-221429) pertaining to the 2016 Long Term Incentive Plan of Goodrich Petroleum Corporation,
3. Registration Statement (Form S-3 333-217675) pertaining to the registration of securities Goodrich Petroleum Corporation may offer and sell not to exceed $250 million,
4. Registration Statement (Form S-8 No. 333-214080) pertaining to the 2016 Long Term Incentive Plan of Goodrich Petroleum Corporation.

of information relating to our firm in the form and content in which they appear in Goodrich Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2019 and to the inclusion of our report dated January 30, 2020 in Goodrich Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2019.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
March 5, 2020

SUITE 800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

Exhibit 31.1

CERTIFICATION PURSUANT TO
15 U.S.C. SECTION 7241
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Walter G. Goodrich, certify that:

1. I have reviewed this annual report on Form 10-K of Goodrich Petroleum Corporation (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiary, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 5, 2020
/s/ Walter G. Goodrich
Walter G. Goodrich
Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
15 U.S.C. SECTION 7241
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robert T. Barker, certify that:

1. I have reviewed this annual report on Form 10-K of Goodrich Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiary, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 5, 2020
/s/ Robert T. Barker

Robert T. Barker
Senior Vice President, Controller, Chief Accounting Officer and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Goodrich Petroleum Corporation (the “Company”) on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Walter G. Goodrich, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002, that, to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Walter G. Goodrich
Walter G. Goodrich
Chief Executive Officer
March 5, 2020

This certification is provided pursuant to Section 906 of the Sarbanes Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes Oxley Act of 2002, be deemed filed by the Company or the certifying officer for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to Goodrich Petroleum Corporation and will be retained by it and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Goodrich Petroleum Corporation (the “Company”) on Form 10-K for the year ended December 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert T. Barker, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002, that, to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert T. Barker
Robert T. Barker
Senior Vice President, Controller, Chief Accounting Officer and Chief Financial Officer
March 5, 2020

This certification is provided pursuant to Section 906 of the Sarbanes Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes Oxley Act of 2002, be deemed filed by the Company or the certifying officer for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to Goodrich Petroleum Corporation and will be retained by it and furnished to the Securities and Exchange Commission or its staff upon request.

February 5, 2020

Mr. Mark E. Ferchau
Goodrich Petroleum Corporation
801 Louisiana Street, Suite 700
Houston, Texas 77002

Dear Mr. Ferchau:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2019, to the Goodrich Petroleum Corporation (Goodrich) interest in certain oil and gas properties located in the United States. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 99 percent of all proved reserves owned by Goodrich. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Goodrich's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Goodrich interest in these properties, as of December 31, 2019, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	12.4	0.1	137,683.4	200,860.0	143,844.1
Proved Developed Non-Producing	0.0	0.0	923.8	160.7	54.6
Proved Undeveloped	0.0	0.0	371,458.8	332,544.5	137,757.3
Total Proved	12.4	0.1	510,066.0	533,565.2	281,656.1

Totals may not add because of rounding.

The oil volumes shown include crude oil only. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. No study was made to determine whether probable or possible reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Goodrich's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Goodrich's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2019. For oil and NGL volumes, the average West Texas Intermediate spot price of $55.69 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.578 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. As requested, economic projections are included in this report to account for the incremental income received from a gas price hedge contract currently in place for certain Haynesville properties located in Louisiana. The average adjusted product prices weighted by production over the remaining lives of the properties are $48.19 per barrel of oil, $12.81 per barrel of NGL, and $2.363 per MCF of gas.

Operating costs used in this report are based on operating expense records of Goodrich. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties are limited to direct lease- and field-level costs and Goodrich's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into per-well costs and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by Goodrich and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Goodrich's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Goodrich interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Goodrich receiving its net revenue interest share of estimated future gross production. Additionally, we have been informed by Goodrich that it is not party to any firm transportation contracts for these properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Goodrich, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and material balance, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Goodrich, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Connor B. Riseden, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 4 years of prior industry experience. Mike K. Norton, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1989 and has over 10 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Connor B. Riseden
Connor B. Riseden, P.E. 100566
Vice Pesident

Date Signed: February 5, 2020

By: /s/ Mike K. Norton
Mike K. Norton, P.G. 441
Senior Vice President

Date Signed: February 5, 2020

LPV:LRG

NETHERLAND, SEWELL & ASSOCIATES, INC.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which 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 gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An 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 gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price 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 upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% 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 (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and 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, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

(i) 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.
(ii) 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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) 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, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.2

GOODRICH PETROLEUM CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2019

Miles. Palke, P.E. TBPE License No. 94894 Managing Senior Vice President	Beau Utley Senior Petroleum Engineer

STATE OF TEXAS
MILES R. PALKE
94894
LICENSED
PROFESSIONAL ENGINEER

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
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January 30, 2020

Goodrich Petroleum Corporation
801 Louisiana, Suite 700
Houston, Texas 77002

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of Goodrich Petroleum Corporation (Goodrich) as of December 31, 2019. The subject properties are located in the states of Louisiana and Mississippi targeting the Tuscaloosa Marine Shale (TMS). The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 24, 2020 and presented herein, was prepared for public disclosure by Goodrich in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.
-
The properties evaluated by Ryder Scott account for a portion of Goodrich's total net proved reserves as of December 31, 2019. Based on information provided by Goodrich, the third party estimate conducted by Ryder Scott addresses 98.8 percent of the total proved developed net liquid hydrocarbon reserves from the TMS. There are no gas reserves associated with these low gas volume producers. There are no proved undeveloped reserves included in this report, at the direction of Goodrich.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2019 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Goodrich Petroleum Corporation
As of December 31, 2019

	Proved		
	Developed		Total
	Producing	Non-Producing	Proved
Net Reserves			
Oil/Condensate – Barrels	1,091,583	0	1,091,583
Income Data ($M)			
Future Gross Revenue	$ 60,117	$ 0	$ 60,117
Deductions	37,012	134	37,146
Future Net Income (FNI)	$ 23,105	$ (134)	$ 22,971
Discounted FNI @ 10%	$ 15,381	$ (84)	$ 15,297

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels. There are no gas reserves since these are low gas volume producers and all gas production is consumed in operations. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. The program was used at the request of Goodrich. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, and certain abandonment costs net of salvage. Other deductions as shown in the cash flow consist of variable expenses based on oil and gas production rates. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for 100 percent total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at five other discount rates which were also compounded annually. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2019 Total Proved	
9	$	15,806
12	$	14,386
15	$	13,236
20	$	11,738
25	$	10,600

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined under the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. All reserves included in this report are proved developed producing. Certain costs associated with wells that will be plugged and abandoned in the near future are summarized in the proved shut-in status category. These wells have no reserves but are included to account for future abandonment expense.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Goodrich's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Goodrich’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Goodrich owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely to be achieved than not.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties that we evaluated were estimated by performance methods. All of the proved producing reserves attributable to producing wells and/or reservoirs that we evaluated were estimated by decline curve analysis, which utilized extrapolations of monthly historical production data available through July 2019, supplemented by daily production data through December 2019 (where available), in those cases where such data were considered to be definitive. There are no proved developed non-producing reserves included in this analysis. The data utilized in this analysis were furnished to Ryder Scott by Goodrich and were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Goodrich has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Goodrich with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Goodrich. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

The future production rates from wells currently on production may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were estimated by Ryder Scott based on information furnished to us by Goodrich. The data furnished to us to calculate differentials were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data supplied by Goodrich to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the “average realized price.” The average realized price shown in the table below was determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
North America				
United States	Oil/Condensate	WTI Cushing	$ 55.69/bbl	$ 60.80/bbl

The effects of derivative instruments designated as price hedges of oil quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Goodrich and are based on the operating expense reports of Goodrich and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Goodrich. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Goodrich. The development cost in this report includes the estimated net cost of abandonment after salvage for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Goodrich were accepted without independent verification.

The proved developed non-producing costs in this report are associated with the abandonment liability for wells that are currently not producing with no future reserves. Abandonment is estimated to occur in 2024 for these three properties.

Current costs used by Goodrich were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Goodrich. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Goodrich**.**

Goodrich makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Goodrich has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-8 of Goodrich of the references to our name as well as to the references to our third party report for Goodrich, which appears in the December 31, 2019 annual report on Form 10-K of Goodrich. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Goodrich.

We have provided Goodrich with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Goodrich and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Miles Palke, P.E.
TBPE License No. 94894
Managing Senior Vice President

STATE OF TEXAS
MILES R. PALKE
94894
LICENSED
PROFESSIONAL ENGINEER

Beau Utley
Senior Petroleum Engineer

MRP-BU (DCR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Miles Robert Palke was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Palke, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2009, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies with extensive experience in the Gulf of Mexico and other regions. Before joining Ryder Scott, Mr. Palke served in a number of engineering positions with BHP Billiton, Ryder Scott Company, and ARCO. For more information regarding Mr. Palke's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Palke earned a Bachelor of Science in Petroleum Engineering from Texas A&M University in College Station TX and a Master of Science in Petroleum Engineering from Stanford University in Palo Alto California. Mr. Palke graduated Magna Cum Laude and with University Honors from Texas A&M University and is a registered Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Palke fulfills. As part of his 2019 continuing education hours, Mr. Palke attended 15 hours of industry and in-house engineering training.

Based on his educational background, professional training and more than 23 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Palke has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and 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, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to 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.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price 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 upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category 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.

(i) 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.

(ii) 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.

(iii) 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, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.