NORTHERN OIL & GAS, INC.
Form 10-K
March 18, 2019
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018

Or

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

For the transition period from ________ to ________

Commission File No. 001-33999

NORTHERN OIL AND GAS, INC.

(*Exact Name of Registrant as Specified in Its Charter*)

Delaware	**95-3848122**
(*State or Other Jurisdiction of Incorporation or Organization*)	*(I.R.S. Employer Identification No.)*

601 Carlson Pkwy – Suite 990, Minnetonka, Minnesota 55305
(*Address of Principal Executive Offices*) (*Zip Code*)
952-476-9800
(*Registrant's Telephone Number, Including Area Code*)

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

Title of Each Class	**Name of Each Exchange On Which Registered**
Common Stock, $0.001 par value	NYSE American

Securities registered pursuant to Section 12(g) of the Act: **None**
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act Yes No ý
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No
Indicate by check mark whether the registrant has submitted electronically 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 ý No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging 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 x
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 Rule 12b-2 of the Exchange Act). Yes No ý

The aggregate market value of the registrant’s voting and non-voting common equity held by non-affiliates of the registrant on the last business day of the registrant’s most recently completed second fiscal quarter (based on the closing sale price as reported by the NYSE American) was approximately $606.1 million.

As of March 14, 2019, the registrant had 376,983,438 shares of common stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement related to the registrant's 2019 Annual Meeting of Stockholders are incorporated by reference into Part III of this report for the year ended December 31, 2018.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

We are including the following discussion to inform our existing and potential security holders generally of some of the risks and uncertainties that can affect our company and to take advantage of the "safe harbor" protection for forward-looking statements that applicable federal securities law affords.

From time to time, our management or persons acting on our behalf may make forward-looking statements to inform existing and potential security holders about our company. All statements other than statements of historical facts included in this report regarding our financial position, business strategy, plans and objectives of management for future operations, industry conditions, and indebtedness covenant compliance are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "continue," "anticipate," "target," "could," "plan," "intend," "seek," "goal," "will," "s
words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about actual or potential future production and sales, cash flows, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond our company's control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following: changes in crude oil and natural gas prices, the pace of drilling and completions activity on our properties, our ability to acquire additional development opportunities, changes in our reserves estimates or the value thereof, general economic or industry conditions, nationally and/or in the communities in which our company conducts business, changes in the interest rate environment, legislation or regulatory requirements, conditions of the securities markets, our ability to raise or access capital, changes in accounting principles, policies or guidelines, financial or political instability, acts of war or terrorism, and other economic, competitive, governmental, regulatory and technical factors affecting our company's operations, products and prices.

We have based any forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, results actually achieved may differ materially from expected results described in these statements. Forward-looking statements speak only as of the date they are made. You should consider carefully the statements in "Item 1A. Risk Factors" and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our company does not undertake, and specifically disclaims, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

Readers are urged not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. We assume no obligation to update any forward-looking statements in order to reflect any event or circumstance that may arise after the date of this report, other than as may be required by applicable law or regulation. Readers are urged to carefully review and consider the various disclosures made by us in our reports filed with the United States Securities and Exchange Commission (the "SEC") which attempt to advise interested parties of the risks and factors that may affect our business, financial condition, results of operation and cash flows. If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, our actual results may vary materially from those expected or projected.

GLOSSARY OF TERMS

Unless otherwise indicated in this report, natural gas volumes are stated at the legal pressure base of the state or geographic area in which the reserves are located at 60 degrees Fahrenheit. Crude oil and natural gas equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

The following definitions shall apply to the technical terms used in this report.

<u>Terms used to describe quantities of crude oil and natural gas:</u>

"*Bbl*." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

"*Boe*." A barrel of oil equivalent and is a standard convention used to express crude oil, NGL and natural gas volumes on a comparable crude oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil or NGL.

"*Boepd.*" Boe per day.

"*Btu or British Thermal Unit*." The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"*MBbl*." One thousand barrels of crude oil, condensate or NGLs.

"*MBoe*." One thousand Boe.

"*Mcf*." One thousand cubic feet of natural gas.

"*MMBbl*." One million barrels of crude oil, condensate or NGLs.

"*MMBoe*." One million Boe.

"*MMBtu*." One million British Thermal Units.

"*MMcf*." One million cubic feet of natural gas.

"*NGLs*." Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

<u>Terms used to describe our interests in wells and acreage:</u>

"*Basin*." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"*Completion*." The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs, and/or natural gas.

"*Conventional play*." An area that is believed to be capable of producing crude oil, NGLs, and natural gas occurring in discrete accumulations in structural and stratigraphic traps.

"*Costless Collar*." An option position where the proceeds from the sale of a call option at its inception fund the purchase of a put option at its inception.

"*Developed acreage.*" Acreage consisting of leased acres spaced or assignable to productive wells. Acreage included in spacing units of infill wells is classified as developed acreage at the time production commences from the initial well in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Development well.*" A well drilled within the proved area of a crude oil, NGL, or natural gas reservoir to the depth of a stratigraphic horizon (rock layer or formation) known to be productive for the purpose of extracting proved crude oil, NGL, or natural gas reserves.

"*Differential.*" The difference between a benchmark price of crude oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

"*Dry hole*." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*Exploratory well.*" A well drilled to find and produce crude oil, NGLs, or natural gas in an unproved area, to find a new reservoir in a field previously found to be producing crude oil, NGLs, or natural gas in another reservoir, or to extend a known reservoir.

"*Field*." 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 field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation*." A layer of rock which has distinct characteristics that differs from nearby rock.

"*Gross acres or Gross wells.*" The total acres or wells, as the case may be, in which a working interest is owned.

"*Held by operations.*" A provision in an oil and gas lease that extends the stated term of the lease as long as drilling operations are ongoing on the property.

"*Held by production.*" A provision in an oil and gas lease that extends the stated term of the lease as long as the property produces a minimum quantity of crude oil, NGLs, and natural gas.

"*Hydraulic fracturing*." The technique of improving a well's production by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"*Infill well.*" A subsequent well drilled in an established spacing unit of an already established productive well in the spacing unit. Acreage on which infill wells are drilled is considered developed commencing with the initial productive well established in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Net acres.*" The percentage ownership of gross acres. Net acres are deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 10% working interest in a lease covering 640 gross acres is equivalent to 64 net acres).

"*Net well.*" A well that is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

"*NYMEX*." The New York Mercantile Exchange.

"*OPEC.*" The Organization of Petroleum Exporting Countries.

"*Productive well*." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

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

"*Reservoir*." A porous and permeable underground formation containing a natural accumulation of producible crude oil, NGLs and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"*Spacing*." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*Unconventional play*." An area believed to be capable of producing crude oil, NGLs, and/or natural gas occurring in cumulations that are regionally extensive but require recently developed technologies to achieve profitability. These areas tend to have low permeability and may be closely associated with source rock as this is the case with crude oil and natural gas shale, tight crude oil and natural gas sands and coal bed methane.

"*Undeveloped acreage*." Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil, NGLs, and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage includes net acres held by operations until a productive well is established in the spacing unit.

"*Unit*." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Wellbore*." The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"*West Texas Intermediate or WTI*." A light, sweet blend of oil produced from the fields in West Texas.

"*Working interest*." The right granted to the lessee of a property to explore for and to produce and own crude oil, NGLs, natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"Workover." Operations on a producing well to restore or increase production.

Terms used to assign a present value to or to classify our reserves:

"*Possible reserves*." The additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

"*Pre-tax PV-10% or PV-10*." The estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the SEC.

"*Probable reserves*." The additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which together with proved reserves, are as likely as not to be recovered.

"*Proved developed producing reserves (PDPs)*." Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil, NGLs, and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"*Proved developed non-producing reserves (PDNPs).*" Proved crude oil, NGLs, and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. 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 started producing, (2) wells that 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 that will require additional completion work or future recompletion prior to the start of production.

"*Proved reserves*." The quantities of crude oil, NGLs and natural gas, which, by analysis of geosciences 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.

"*Proved undeveloped drilling location.*" A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"*Proved undeveloped reserves*" or "*PUDs*." 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 development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not 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 tests in the area and in the same reservoir or an analogous reservoir.

(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 crude oil, NGLs or natural 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 during the twelve-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.

"*Standardized measure*." Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

NORTHERN OIL AND GAS, INC.

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ANNUAL REPORT ON FORM 10-K
FOR FISCAL YEAR ENDED DECEMBER 31, 2018
PART I
Item 1. ***Business***

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas properties, primarily in the Bakken and Three Forks formations within the Williston Basin in North Dakota and Montana. We believe the location, size and concentration of our acreage position in one of North America's leading unconventional oil-resource plays provide us with drilling and development opportunities that will result in significant long-term value.

Our primary focus is acquiring and participating in the development of non-operated working interests in oil wells in the Williston Basin. As a non-operator, we are able to diversify our investment exposure by participating in a large number of gross wells, as well as entering into additional project areas by partnering with numerous experienced operating partners or pursuing value-enhancing acquisitions. In addition, because we can elect to participate on a well-by-well basis, we believe we have increased flexibility in the timing and amount of our capital expenditures because we are not burdened with various contractual arrangements with respect to minimum drilling obligations. Further, we are able to avoid exploratory and infrastructure costs incurred by many oil and gas producers.

We seek to create value through strategic acquisitions and partnering with operators who have experience in developing and producing oil in our core areas. We have more than 40 experienced operating partners that provide technical insights and opportunities for acquisitions. Historically, our core acquisition strategy has been to seek to acquire smaller lease positions at a significant discount to the contiguous acreage positions typically sought by larger producers and operators of oil wells. Such acquisitions, including wellbore acquisitions, have been a significant driver of our historical net well additions and additions to production.

During 2018, in addition to the foregoing, we significantly accelerated our growth through several larger acquisitions of non-operated asset packages:

•***W Energy Acquisition***. On October 1, 2018, we closed on an acquisition of approximately 27.2 net producing wells, 5.9 net wells in process and 10,633 net acres in North Dakota from WR Operating LLC (the "W Energy Acquisition").

•***Pivotal Acquisition***. On September 17, 2018, we closed on acquisitions of approximately 20.8 net producing wells, 2.2 net wells in process and 444 net acres in North Dakota from Pivotal Williston Basin, LP and Pivotal Williston Basin II, LP (the "Pivotal Acquisition").

•***Salt Creek Acquisition***. On June 4, 2018, we closed on an acquisition of approximately 5.5 net producing wells, 1.5 net wells in process and 1,319 net acres in North Dakota from Salt Creek Oil and Gas, LLC (the "Salt Creek Acquisition").

We estimate that these three acquisitions contributed approximately 32%, or 11,503 Boe per day, of our average daily production in the fourth quarter of 2018.

During 2018, we added a total of 1,536 gross (97.0 net) producing wells in the Williston Basin, including 65.8 net wells from acquisitions. At December 31, 2018, we owned working interests in 4,792 gross (325.1 net) producing wells, with substantially all the wells targeting the Bakken and Three Forks formations. As of December 31, 2018, we leased approximately 157,083 net acres, all located in the Williston Basin, of which approximately 144,208 net acres were developed.

As of December 31, 2018, our proved reserves were 135.5 MMBoe (all of which are in the Williston Basin) as estimated by our third-party independent reserve engineers, Cawley, Gillespie & Associates, Inc. As of December 31, 2018, 56% of our proved reserves were classified as proved developed and 83% of our proved reserves were oil. The following table provides a summary of certain information regarding our assets:

	As of December 31, 2018						
	Net Acres	Productive Wells		Average Daily Production(1) (Boe per day)	Proved Reserves (MBoe)	% Oil	% Proved Developed
		Gross	Net				
North Dakota	141,733	4,693	314.1	35,691	134,578	83 %	56 %
Montana	15,359	99	11.0	567	906	87	100
Total	157,092	4,792	325.1	36,258	135,484	83 %	56 %

(1) Represents the average daily production over the three months ended December 31, 2018.

Business Strategy

Key elements of our business strategies include:

•*Diversify Our Risk Through Non-Operated Participation in a Large Number of Wells.* As a non-operator, we seek to diversify our investment and operational risk through participation in a large number of oil wells and with multiple operators. As of December 31, 2018, we have participated in 4,792 gross (325.1 net) producing wells in the Williston Basin with an average working interest of 6.8% in each gross well, with more than 40 experienced operating partners. We believe the best way to develop our acreage is to take a long-term approach and to participate in the development of our locations with potential for the highest rates of return.

•*Accelerate Growth by Pursuing Value-Enhancing Acquisitions.* We strive to be the natural consolidator and clearing house of non-operated working interest in the Williston Basin. Historically, our core acquisition strategy has been to seek to acquire smaller lease positions at a significant discount to the contiguous acreage positions typically sought by larger producers and operators of oil wells, focusing on near term drilling opportunities. Such acquisitions have been a significant driver of our net well additions and additions to production. We intend to continue these activities, while at the same time evaluating and pursuing larger non-operated asset packages that we believe can responsibly accelerate our growth strategy.

•*Build and Maintain a Strong Balance Sheet and Proactively Manage to Limit Downside.* We strive for financial strength and flexibility through the prudent management of our balance sheet and active management of commodity price volatility. Additionally, given the volatility of the commodity price environment, we employ an active commodity price risk management program to better enable us to execute our business plan over the entire commodity price cycle. The following table summarizes the open oil derivative contracts (excluding basis swaps) that we have entered into as of December 31, 2018, by year:

Open Contracts		
Year	**Swap Volumes (Bbl)**	**Weighted Average Swap Price ($)**
2019	6,851,730	63.32
2020	4,186,080	61.01

2021 and beyond	1,310,100	61.18

Industry Operating Environment

The oil and natural gas industry is a global market impacted by many factors, such as government regulations, particularly in the areas of taxation, energy, climate change and the environment, political and social developments in the Middle East, demand in Asian and European markets, and the extent to which members of OPEC and other oil exporting nations manage oil supply through export quotas. Natural gas prices are generally determined by North American supply and demand and are also affected by imports and exports of liquefied natural gas. Weather also has a significant impact on demand for natural gas since it is a primary heating source.

Oil and natural gas prices have been, and we expect may continue to be, volatile. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices may affect planned capital expenditures and the oil and natural gas reserves that we can economically produce. Lower oil and gas prices may also reduce the amount of our borrowing base under our revolving credit facility, which is determined at the discretion of the lenders based on various factors including the collateral value of our proved reserves.

While lower commodity prices may reduce our future net cash flow from operations, we expect to have sufficient liquidity to continue development of our oil and gas properties. At December 31, 2018, the borrowing base on our revolving credit facility was $425.0 million and we had $140.0 million of borrowings outstanding thereunder, leaving $285.0 million of borrowing availability under the facility. In addition, we undertake an active commodity hedging program that helps stabilize a volatile commodity pricing environment and protect cash flows in a potential downturn.

Development

We primarily engage in oil and natural gas exploration and production by participating on a proportionate basis alongside third-party interests in wells drilled and completed in spacing units that include our acreage. In addition, we acquire wellbore-only working interests in wells in which we do not hold the underlying leasehold interests from third parties unable or unwilling to participate in particular well proposals. We typically depend on drilling partners to propose, permit and initiate the drilling of wells. Prior to commencing drilling, our partners are required to provide all owners of oil, natural gas and mineral interests within the designated spacing unit the opportunity to participate in the drilling costs and revenues of the well to the extent of their pro-rata share of such interest within the spacing unit. We assess each drilling opportunity on a case-by-case basis and participate in wells that we expect to meet our return thresholds based upon our estimates of ultimate recoverable oil and natural gas, expected oil and gas prices, expertise of the operator, and completed well cost from each project, as well as other factors. Historically, we have participated pursuant to our working interest in a vast majority of the wells proposed to us. However, declines in oil prices typically reduce both the number of well proposals we receive and the proportion of well proposals in which we elect to participate. Our land and engineering team uses our extensive database to make these economic decisions. Given our large acreage footprint and substantial number of well participations, we believe we can make accurate economic drilling decisions.

We do not manage our commodities marketing activities internally, but our operating partners generally market and sell oil and natural gas produced from wells in which we have an interest. Our operating partners coordinate the transportation of our oil production from our wells to appropriate pipelines or rail transport facilities pursuant to arrangements that such partners negotiate and maintain with various parties purchasing the production. We understand that our partners generally sell our production to a variety of purchasers at prevailing market prices under separately negotiated short-term contracts. The price at which production is sold generally is tied to the spot market for oil. Williston Basin Light Sweet Crude from the Bakken source rock is generally 41-42 API crude oil and is readily accepted into the pipeline infrastructure. The weighted average differential reported to us by our operating partners during 2018 was $7.12 per barrel below NYMEX pricing. Our weighted average differential was approximately $10.13 per barrel below NYMEX pricing during the fourth quarter of 2018. This differential represents the imbedded transportation costs in moving the oil from wellhead to refinery and will fluctuate based on availability of pipeline, rail and other transportation methods. Using our commodity hedging program, we may, from time to time, enter into financial hedging contracts to help mitigate pricing risk and volatility with respect to differentials.

Competition

The oil and natural gas industry is intensely competitive and we compete with numerous other oil and natural gas exploration and production companies, many of which have substantially greater resources than we have and may be able to pay more for exploratory prospects and productive oil and natural gas properties. Our larger or integrated competitors may be better able to absorb the burden of existing, and any changes to federal, state, and local laws and regulations than we can, which would adversely affect our competitive position. Our ability to discover reserves and acquire additional properties in the future is dependent upon our ability and resources to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Marketing and Customers

The market for oil and natural gas that will be produced from our properties depends on many factors, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is expected to be sold at prices tied to the spot oil markets. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices. We rely on our operating partners to market and sell our production. Our operating partners include a variety of exploration and production companies, from large publicly-traded companies to small, privately-owned companies. We do not believe the loss of any single operator would have a material adverse effect on our company as a whole.

Title to Properties

Our oil and natural gas properties are subject to customary royalty and other interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. A significant portion of our indebtedness, including under our revolving credit facility and senior secured notes, is also secured by liens on substantially all of our assets. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

We believe that we have satisfactory title to or rights in our producing properties. As is customary in the oil and gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title only when we acquire producing properties or before commencement of drilling operations.

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt the drilling and producing activities of our operating partners and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt the operations of our operating partners and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operating partners' operations.

Principal Agreements Affecting Our Ordinary Business

We do not own any physical real estate, but, instead, our acreage is comprised of leasehold interests subject to the terms and provisions of lease agreements that provide our company the right to participate in drilling and maintenance of wells in specific geographic areas. Lease arrangements that comprise our acreage positions are generally established using industry-standard terms that have been established and used in the oil and natural gas industry for many years. Some of our leases may be acquired from other parties that obtained the original leasehold interest prior to our acquisition of the leasehold interest.

In general, our lease agreements stipulate three-to-five year terms. Bonuses and royalty rates are negotiated on a case-by-case basis consistent with industry standard pricing. Once a well is drilled and production established, the leased acreage in the applicable spacing unit is considered developed acreage and is held by production. Other locations within the drilling unit created for a well may also be drilled at any time with no time limit as long as the lease is held by production. Given the current pace of drilling in the Bakken play at this time, we do not believe lease expiration issues will materially affect our North Dakota position.

Governmental Regulation and Environmental Matters

Our operations are subject to various rules, regulations and limitations impacting the oil and natural gas exploration and production industry as whole.

Regulation of Oil and Natural Gas Production

Our oil and natural gas exploration, production and related operations are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, North Dakota and Montana require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of oil and natural gas. Such states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the process of drilling, completion and abandonment, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill. Moreover, many states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions. Failure to comply with any such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. On December 17, 2015, the FERC established a new price index for the five-year period which commenced on July 1, 2016.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally governed by pro-rationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future.

Onshore gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case-by-case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Environmental Matters

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue. These laws and regulations may:

•require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities;

•limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and

•impose substantial liabilities for pollution resulting from its operations.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on our company, as well as the oil and natural gas industry in general.

The Comprehensive Environmental, Response, Compensation, and Liability Act ("CERCLA") and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. Recent regulation and litigation that has been brought against others in the industry under RCRA concern liability for earthquakes that were allegedly caused by injection of oil field wastes.

The Endangered Species Act ("ESA") seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, nor destroy or modify the critical habitat of such species. Under ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. ESA provides for criminal penalties for willful violations of ESA. Other statutes that provide protection to animal and plant species and that may apply to our operations include, but are not necessarily limited to, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although we believe that our operations are in substantial compliance with such statutes, any change in these statutes or any reclassification of a species as endangered could subject our company (directly or indirectly through our operating partners) to significant expenses to modify our operations or could force discontinuation of certain operations altogether.

The Clean Air Act ("CAA") controls air emissions from oil and natural gas production and natural gas processing operations, among other sources. CAA regulations include New Source Performance Standards ("NSPS") for the oil and natural gas source category to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”) and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities.

On September 18, 2015, the EPA proposed to further amend the NSPS for the oil and natural gas source category to set standards for methane and VOC emissions from new and modified oil and gas production sources and natural gas-processing and transmission sources. These regulations were finalized and published in the Federal Register on June 3, 2016. Although these regulations are still in effect, they are being reconsidered by the Trump Administration EPA. Although we cannot predict the cost to comply with these new requirements at this point, or to what extent they may or may not be changed upon review, compliance with these new rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

These new regulations and proposals and any other new regulations requiring the installation of more sophisticated pollution control equipment could have a material adverse impact on our business, results of operations and financial condition.

The Federal Water Pollution Control Act of 1972, or the Clean Water Act (the "CWA"), imposes restrictions and controls on the discharge of produced waters and other pollutants into waters of the United States ("WOTUS"). Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The CWA and certain state regulations prohibit the discharge of produced water, sand, drilling fluids, drill cuttings, sediment and certain other substances related to the oil and gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. CWA jurisdiction depends on the definition of WOTUS. This definition has been in flux since 2015, when US EPA and the Army Corps of Engineers enacted regulations to more broadly define WOTUS, thereby potentially expanding CWA jurisdiction. The 2015 WOTUS rule is subject to numerous legal challenges, which have left the new definition in place in 26 states but enjoined in 24 states, including Montana and North Dakota. Furthering uncertainty about CWA jurisdiction, in February 2019, US EPA and the Army Corps of Engineers proposed a replacement WOTUS rule circumscribing CWA jurisdiction. This rule will likely also be challenged once it is finally promulgated. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Although the federal CWA is currently interpreted not to regulate discharges to groundwater, on February 21, 2019, the United States Supreme Court accepted jurisdiction to review the case *County of Maui v. Hawaii Wildlife Fund*, No. 18-260, which raises the question whether the federal CWA regulates pollutants that originate from a point source but are only conveyed to navigable water through groundwater. Costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges, for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release.

The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Substantially all of the oil and natural gas production in which we have interest is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress continues to consider legislation to amend the Safe Drinking Water Act to address hydraulic fracturing operations.

Scrutiny of hydraulic fracturing activities continues in other ways. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts. Several states, including Montana and North Dakota where our properties are located, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities in other states, including Colorado and Texas, have enacted bans on hydraulic fracturing. New York State's ban on hydraulic fracturing was recently upheld by the Courts. In Colorado, the Colorado Supreme Court has ruled the municipal bans were preempted by state law. We cannot predict whether any other legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, which could lead to delays, increased operating costs and process prohibitions that would materially adversely affect our revenue and results of operations.

The National Environmental Policy Act ("NEPA") establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA. Many of the activities of our third-party operating partners are covered under categorical exclusions which results in a shorter NEPA review process. The Council on Environmental Quality has announced an intention to reinvigorate NEPA reviews and on March 12, 2012, issued final guidance that may result in longer review processes that could lead to delays and increased costs that could materially adversely affect our revenues and results of operations.

Climate Change

Significant studies and research have been devoted to climate change, and climate change has developed into a major political issue in the United States and globally. Certain research suggests that greenhouse gas emissions contribute to climate change and pose a threat to the environment. Recent scientific research and political debate has focused in part on carbon dioxide and methane incidental to oil and natural gas exploration and production.

In the United States, legislative and regulatory initiatives are underway to limit greenhouse gas ("GHG") emissions. The U.S. Congress has considered legislation that would control GHG emissions through a "cap and trade" program and several states have already implemented programs to reduce GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the CAA definition of an "air pollutant." Recent litigation has held that if a source was subject to Prevention of Significant Deterioration ("PSD") or Title V based on emissions of conventional pollutants like sulfur dioxide, particulates, nitrogen dioxide, carbon monoxide, ozone or lead, then the EPA could also require the source to control GHG emissions and the source would have to install Best Available Control Technology to do so. As a result, a source may still have to control GHG emissions if it is an otherwise regulated source.

On February 23, 2014, Colorado became the first state in the nation to adopt rules to control methane emissions from oil and gas facilities. On June 3, 2016, EPA issued three final rules that were intended to curb emissions of methane, VOCs and toxic air pollutants such as benzene from new, reconstructed and modified oil and gas sources. These new regulations include leak detection and repair provisions, and may require controls to reduce methane emissions from certain oil and gas facilities. To the extent that these regulations remain in place and to the extent that our third party operating partners are required to further control methane emissions, such controls could impact our business.

In addition, our third party operating partners are required to report their greenhouse gas emissions under CAA rules. Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact us. Moreover, while the U.S. Supreme Court held in its June 2011 decision *American Electric Power Co. v. Connecticut* that, with respect to claims concerning GHG emissions, the federal common law of nuisance was displaced by the CAA, the Court left open the question of whether tort claims against sources of GHG emissions alleging property damage may proceed under state common law. There thus remains some litigation risk for such claims. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on us.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The majority of scientific studies on climate change suggest that stronger storms may occur in the future in the areas where we operate, although the scientific studies are not unanimous. Although operators may take steps to mitigate physical risks from storms, no assurance can be given that future storms will not have a material adverse effect on our business.

Employees

As of December 31, 2018, we had 20 full time employees. We may hire additional technical or administrative personnel as appropriate. We also use the services of independent consultants and contractors to perform various professional services.

Office Locations

Our executive offices are located at 601 Carlson Pkwy, Suite 990, Minnetonka, Minnesota 55305. Our office space consists of 8,295 square feet of leased space. We believe our current office space is sufficient to meet our needs for the foreseeable future.

Organizational Background

On May 9, 2018, we filed articles of conversion with the Secretary of State of the State of Minnesota and filed a certificate of conversion with the Secretary of State of the State of Delaware changing our jurisdiction of incorporation from Minnesota to Delaware (the "Reincorporation"). The Reincorporation was approved by our stockholders at a special meeting held on May 8, 2018. Upon the Reincorporation, each outstanding certificate representing shares of the Minnesota corporation's common stock was deemed, without any action by the holders thereof, to represent the same number and class of shares of our company's common stock. As of May 9, 2018, the rights of our stockholders began to be governed by Delaware General Corporation Law and our Delaware certificate of incorporation and bylaws. On August 23, 2018, the stockholders of the company, upon recommendation of the Board of Directors, approved an amendment to the Certificate of Incorporation to increase the number of authorized shares of common stock to 675,000,000. On August 24, 2018, the Company restated its Certificate of Incorporation to integrate all prior amendments.

Available Information – Reports to Security Holders

Our website address is www.northernoil.com. We make available on this website, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and amendments to those reports as soon as reasonably practicable after we electronically file those materials with, or furnish those materials to, the SEC. Electronic filings with the SEC are also available on the SEC internet website at www.sec.gov.

We have also posted to our website our Audit Committee Charter, Compensation Committee Charter, Nominating Committee Charter and our Code of Business Conduct and Ethics, in addition to all pertinent company contact information.

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

Oil and natural gas prices are volatile. Extended declines in oil and natural gas prices have adversely affected, and could in the future adversely affect, our business, financial position, results of operations and cash flow.

The oil and natural gas markets are very volatile, and we cannot predict future oil and natural gas prices. Oil and natural gas prices declined significantly starting in 2014 and have fluctuated significantly since that time. The prices we receive for our oil and natural gas production heavily influences our revenue, cash flows, profitability, access to capital and future rate of growth. Although we seek to mitigate volatility and potential declines in oil prices through derivative arrangements that hedge a portion of our expected production, this merely seeks to mitigate (not eliminate) these risks, and such activities come with their own risks.

The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

•changes in global supply and demand for oil and natural gas;

•the actions of OPEC and other major oil producing countries;

•the price and quantity of imports of foreign oil and natural gas;

•political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity;

•the level of global oil and natural gas exploration and production activity;

•the level of global oil and natural gas inventories;

•changes in U.S. energy policy;

•weather conditions;

•technological advances affecting energy consumption;

•domestic and foreign governmental tariffs and/or regulations;

•proximity and capacity of oil and natural gas pipelines and other transportation facilities;

•the price and availability of competitors’ supplies of oil and natural gas in captive market areas; and

•the price and availability of alternative fuels.

These factors and the volatility of the energy markets make it extremely difficult to predict oil and natural gas prices. Lower oil and natural gas prices have in the past and may in the future adversely affect our revenues, the amount of oil and natural gas that our operators can produce economically, and our reserve bookings. A substantial or extended decline in oil or natural gas prices, such as the depressed commodity price environment that we’ve experienced since late 2014, has resulted in and could result in future impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we may be required to reduce spending or borrow or issue additional equity to cover any such shortfall. Lower oil and natural gas prices may limit our ability to comply with the covenants under our revolving credit facility (or other debt instruments) and/or limit our ability to access borrowing availability thereunder, which is dependent on many factors including the value of our proved reserves.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Determining the amount of oil and natural gas recoverable from various formations involves significant complexity and uncertainty. No one can measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and/or natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating, exploration and development costs. Some of our reserve estimates are made without the benefit of a lengthy production history and are less reliable than estimates based on a lengthy production history. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate.

We routinely make estimates of oil and natural gas reserves in connection with managing our business and preparing reports to our lenders and investors. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, development schedules, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, reserve engineers and other advisors to make accurate assumptions. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, natural gas and NGLs we ultimately recover being different from our reserve estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K, subsequent reports we file with the SEC or other company materials. In addition, we may adjust estimates of net proved reserves to reflect production history, changes in operating costs, results of exploration and development, prevailing oil and natural gas prices and any other factors, many of which are beyond our control.

Drilling for and producing oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our financial condition or results of operations.

Our operators’ drilling activities are subject to many risks, including the risk that they will not discover commercially productive reservoirs. Drilling for oil or natural gas can be uneconomical, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, drilling and producing operations on our acreage may be curtailed, delayed or canceled by our operators as a result of other factors, including:

•declines in oil or natural gas prices;

•the high cost, shortages or delivery delays of equipment and services;

•shortages of or delays in obtaining water for hydraulic fracturing operations;

•unexpected operational events;

•adverse weather conditions;

•facility or equipment malfunctions;

•title problems;

•pipeline ruptures or spills;

•compliance with environmental and other governmental requirements;

•regulations, restrictions, moratoria and bans on hydraulic fracturing;

•unusual or unexpected geological formations;

•loss of drilling fluid circulation;

•formations with abnormal pressures;

•environmental hazards, such as oil, natural gas or well fluids spills or releases, pipeline or tank ruptures and discharges of toxic gas;

•fires;

•blowouts, craterings and explosions;

•uncontrollable flows of oil, natural gas or well fluids; and

•pipeline capacity curtailments.

Any of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties.

We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Due to the declines in oil and natural gas prices, we have taken significant writedowns of our oil and natural gas properties. We may be required to record further writedowns of our oil and natural gas properties.

In 2015 and 2016 we were required to write down the carrying value of certain of our oil and natural gas properties, and further writedowns could be required in the future. Writedowns may occur when oil and natural gas prices are low, or if we have downward adjustments to our estimated proved reserves, increases in our estimates of operating or development costs, deterioration in drilling results or mechanical problems with wells where the cost to redrill or repair is not supported by the expected economics.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are subject to amortization. Should capitalized costs exceed this ceiling, an impairment would be recognized.

Our company did not record any impairments during 2017 or 2018, but if a lower pricing environment reoccurs we could be required to further write down the value of our oil and natural gas properties. If lower average monthly pricing is reflected in the trailing twelve-month average pricing calculation, the present value of our future net revenues could decline and one or more impairments could be recognized. The quarterly ceiling test considers many factors including reserves, capital expenditure estimates and trailing twelve-month average prices. SEC defined prices for each quarter in 2018 were as follows:

SEC Defined Prices for 12 Months Ended	**NYMEX Oil Price (per Bbl)**		**Henry Hub Gas Price (per MMBtu)**	
December 31, 2018	$	65.56	$	3.10
September 30, 2018	63.43		2.91	

June 30, 2018	57.67	2.92
March 31, 2018	53.49	3.00

Any significant reduction in our borrowing base under our revolving credit facility, and any limit on our ability to comply with the financial covenants thereunder, will negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility or any other obligation if required as a result of a borrowing base reduction.

Availability under our revolving credit facility is subject to a borrowing base, with scheduled semiannual (April 1 and October 1) and other elective borrowing base redeterminations based upon, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the revolving credit facility. The lenders under the revolving credit facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Our revolving credit facility includes covenants that require the ratio of (a) our Total Net Debt (as defined therein) to (b) EBITDAX (as defined therein), to not exceed 4.00 to 1.00 and (ii) the ratio of Current Assets (as defined therein) to Current Liabilities (as defined therein) to be greater than or equal to 1.00 to 1.00, in each case, as of the last day of any fiscal quarter. Reductions in estimates of our producing oil, NGL and natural gas reserves could result in a reduction of our borrowing base thereunder. The same could also arise from other factors, including but not limited to:

•lower commodity prices or production;

•inability to drill or unfavorable drilling results;

•changes in crude oil, NGL and natural gas reserve engineering; or

•increased operating and/or capital costs.

As of December 31, 2018, we had $140.0 million of borrowings outstanding under our revolving credit facility. We expect to make further borrowings under our revolving credit facility in the future. Any significant reduction in our borrowing base could result in a default under current and/or future debt instruments, negatively impact our liquidity and our ability to fund our operations and, as a result, could have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess. If we do not have sufficient funds and we are otherwise unable to arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Our future success depends on our ability to replace reserves that our operators produce.

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and natural gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as our reserves are produced. We have added significant net wells and production from wellbore-only acquisitions, where we don’t hold the underlying leasehold interest that would entitle us to participate in future wells. For example, our Pivotal Acquisition in 2018 consisted primarily of producing wellbore interests without associated future development rights. Future oil and natural gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

We may acquire significant amounts of unproved property to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We seek to acquire both proved and producing properties as well as undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot assure you that all of these properties will contain economically viable reserves or that we will not abandon our initial investments. Additionally, we cannot assure you that unproved reserves or undeveloped acreage that we acquire will be profitably developed, that new wells drilled on our properties will be productive or that we will recover all or any portion of our investments in our properties and reserves.

As a non-operator, our development of successful operations relies extensively on third-parties, which could have a material adverse effect on our results of operation.

We have only participated in wells operated by third parties. The success of our business operations depends on the timing of drilling activities and success of our third-party operators. If our operators are not successful in the development, exploitation, production and exploration activities relating to our leasehold interests, or are unable or unwilling to perform, our financial condition and results of operation would be materially adversely affected.

These risks are heightened in a low commodity price environment, which may present significant challenges to our operators. The challenges and risks faced by our operators may be similar to or greater than our own, including with respect to their ability to service their debt, remain in compliance with their debt instruments and, if necessary, access additional capital. Certain oil and gas operators filed for bankruptcy as a result of the low commodity price environment that began in 2014 and a low commodity price environment could result in additional operators being forced into bankruptcy. The insolvency of an operator of any of our properties, the failure of an operator of any of our properties to adequately perform operations or an operator's breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner. Finally, an operator of our properties may have the right, if another non-operator fails to pay its share of costs because of its insolvency or otherwise, to require us to pay our proportionate share of the defaulting party's share of costs.

Our operators will make decisions in connection with their operations (subject to their contractual and legal obligations to other owners of working interests), which may not be in our best interests.

Additionally, we may have virtually no ability to exercise influence over the operational decisions of our operators, including the setting of capital expenditure budgets and drilling locations and schedules. Dependence on our operators could prevent us from realizing our target returns for those locations. The success and timing of development activities by our operators will depend on a number of factors that will largely be outside of our control, including:

•oil and natural gas prices and other factors generally affecting industry operating environment;

•the timing and amount of capital expenditures;

•their expertise and financial resources;

•approval of other participants in drilling wells;

•selection of technology; and

•the rate of production of reserves, if any.

We could experience periods of higher costs as activity levels in the Williston Basin fluctuate or if commodity prices rise. These increases could reduce our profitability, cash flow, and ability to complete development activities as planned.

The recent rise in commodity prices has increased activity and investment in the Williston Basin. As a result of increased activity in the Williston Basin, competition for equipment, labor and supplies is also expected to increase. Likewise, higher oil, natural gas and NGL prices generally increase the demand for equipment, labor and supplies, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our operating partners' ability to drill the wells and conduct the operations that we currently expect.

In addition, capital and operating costs in the oil and natural gas industry have generally risen during periods of increasing commodity prices as producers seek to increase production in order to capitalize on higher commodity prices. In situations where cost inflation exceeds commodity price inflation, our profitability and cash flow, and our operators' ability to complete development activities as scheduled and on budget, may be negatively impacted. Any delay in the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash available to make payments on our debt obligations.

Our lack of industry and geographical diversification may increase the risk of an investment in our company.

Our business focus is on the oil and natural gas industry in properties that are primarily in the areas of the Williston Basin located in Montana and North Dakota. While other companies may have the ability to manage their risk by diversification, the narrow focus of our business, in terms of both the industry focus and geographic scope of our business, means that we will likely be impacted more acutely by factors affecting our industry or the region in which we operate than we would if our business were more diversified. As a result of the narrow focus of our business, we may be disproportionately exposed to the effects of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of oil or natural gas. Additionally, we may be exposed to further risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within the Williston Basin.

Locations that the operators of our properties decide to drill may not yield oil or natural gas in commercially viable quantities.

The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if the operators of our properties drill dry holes or wells that are productive but do not produce enough to be commercially viable after drilling, operating and other costs. If the operators of our properties drill future wells that are identified as dry holes, the drilling success rate would decline and may adversely affect our results of operations.

To the extent we are unable to obtain future hedges at attractive prices or our derivative activities are not effective, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the price of oil, we enter into derivative instrument contracts for a portion of our expected oil production, including swaps, collars, puts and basis swaps. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included on our balance sheet as assets or liabilities and in our statements of income as gain (loss) on derivatives, net. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative instruments.

Our derivatives activities could result in financial losses or could reduce our cash flow.

We enter into swaps, collars or other derivatives arrangements from time to time to hedge our expected production depending on projected production levels and expected market conditions. While intended to mitigate the effects of volatile oil and natural gas prices, such transactions may limit our potential gains and increase our potential losses if oil and natural gas prices were to rise substantially over the price established by the hedge.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

•a counterparty to our derivative contracts is unable to satisfy its obligations under the contracts;

•our production is less than expected; or

•there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement.

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Our ability to use net operating loss carryforwards to offset future taxable income may be subject to certain limitations.

We have net operating loss ("NOL") carryforwards that we may use to offset against taxable income for U.S. federal income tax purposes. At December 31, 2018, we had an estimated NOL carryforward of approximately $370.5 million for United States federal income tax purposes. In general, under Section 382 of the Internal Revenue Code of 1986, as amended (the "IRC"), a corporation that undergoes an "ownership change" can be subject to limitations on the use of its NOLs to offset future taxable income. We underwent an "ownership change" during 2018 and, as a result, the use of our existing NOL carryforwards are subject to limitations under Section 382, which are generally determined by multiplying the value of our stock at the time of the ownership change by the applicable long term tax exempt rate as defined in Section 382. See Note 10 to our financial statements. Future changes in our stock ownership, some of which are outside of our control, could result in an additional ownership change under Section 382 of the IRC.

Changes in United States federal income tax law may have an adverse effect on our cash flows, results of operations or financial condition overall

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Act") that significantly reformed the IRC. The Act, among other things, (i) reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) eliminates the deduction for certain domestic production activities, (iv) imposes new limitations on the utilization of net operating losses, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. The Act is complex and far-reaching and we cannot predict with certainty the resulting impact its enactment has on us. The ultimate impact of the Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued and any such changes in interpretations or assumptions could adversely affect our business and financial condition. See Note 10 to our financial statements.

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

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for natural gas and oil properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these provisions were largely unchanged in the Tax Act, Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation. Moreover, other more general features of any additional tax reform legislation, including changes to cost recovery rules, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted in future legislation and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development or increase costs, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated proved reserves.

We base the estimated discounted future net cash flows from our proved reserves using a 12-month average price and costs in effect on the day of the estimate. However, actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

•the volume, pricing and duration of our oil and natural gas hedging contracts;

•actual prices we receive for oil, natural gas and NGLs;

•our actual operating costs in producing oil, natural gas and NGLs;

•the amount and timing of our capital expenditures;

•the amount and timing of actual production; and

•changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our business depends on oil and natural gas transportation and processing facilities and other assets that are owned by third parties.

The marketability of our oil and natural gas depends in part on the availability, proximity and capacity of pipeline systems, processing facilities, oil trucking fleets and rail transportation assets owned by third parties. The lack of available capacity on these systems and facilities, whether as a result of proration, physical damage, scheduled maintenance or other reasons, could result in a substantial increase in costs, the shut-in of producing wells or the delay or discontinuance of development plans for our properties. The negative effects arising from these and similar circumstances may last for an extended period of time. In many cases, operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, many of our wells are drilled in locations in the Williston Basin that are serviced to a limited extent, if at all, by gathering and transportation pipelines, which may or may not have sufficient capacity to transport production from all of the wells in the area. As a result, we rely on third party oil trucking to transport a significant portion of our production to third party transportation pipelines, rail loading facilities and other market access points. Any significant curtailment in gathering system or pipeline capacity, or the unavailability of sufficient third party trucking or rail capacity, could adversely affect our business, results of operations and financial condition.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established or operations are commenced on units containing the acreage or the leases are extended.

A significant portion of our acreage is not currently held by production or held by operations. Unless production in paying quantities is established or operations are commenced on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to participate in the development of the related properties. Drilling plans for these areas are generally in the discretion of third party operators and are subject to change based on various factors that are beyond our control, such as: the availability and cost of capital, equipment, services and personnel; seasonal conditions; regulatory and third party approvals; oil, NGL and natural gas prices; results of title work; gathering system and other transportation constraints; drilling costs and results; and production costs. As of December 31, 2018, we estimate that we had leases that were not developed that represented 5,160 net acres potentially expiring in 2019, 907 net acres potentially expiring in 2020, 1,428
net acres expiring in 2022, and 3,324 and net acres potentially expiring in 2023 and beyond.

Seasonal weather conditions adversely affect operators' ability to conduct drilling activities in the areas where our properties are located.

Seasonal weather conditions can limit drilling and producing activities and other operations in our operating areas and as a result, a majority of the drilling on our properties is generally performed during the summer and fall months. These seasonal constraints can pose challenges for meeting well drilling objectives and increase competition for equipment, supplies and personnel during the summer and fall months, which could lead to shortages and increase costs or delay operations. Additionally, many municipalities impose weight restrictions on the paved roads that lead to jobsites due to the muddy conditions caused by spring thaws. This could limit access to jobsites and operators' ability to service wells in these areas.

Significant capital expenditures are required to develop our properties and replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, borrowings under our credit facilities, debt issuances, and equity issuances. We have also engaged in asset sales from time to time. If our access to capital were limited due to numerous factors, which could include a decrease in operating cash flow due to lower oil and natural gas prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to develop our properties and replace our reserves. We may not be able to incur additional debt under our revolving credit facility, issue debt or equity, engage in asset sales or access other methods of financing on acceptable terms to develop our properties and/or meet our reserve replacement requirements.

We may be unable to obtain additional capital that we will require to implement our business plan.

Future acquisitions and future exploration, development, production and marketing activities, will require a substantial amount of capital. Cash reserves, cash from operations and borrowings under our revolving credit facility may not be sufficient to fund both our continuing operations and our planned growth. We may require additional capital to continue to grow our business through acquisitions and to further expand our exploration and development programs. We may be unable to obtain additional capital if and when required.

We may pursue sources of additional capital through various financing transactions or arrangements, including joint venturing of projects, debt financing, equity financing or other means. We may not be successful in consummating suitable financing transactions in the time period required or at all, and we may not be able to obtain the capital we require by other means. If the amount of capital we are able to raise from financing activities, together with our cash from operations, is not sufficient to satisfy our capital requirements, we may not be able to implement our business plan and may be required to scale back our operations, sell assets at unattractive prices or obtain financing on unattractive terms, any of which could adversely affect our business, results of operations and financial condition.

The development of our proved undeveloped reserves in the Williston Basin and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 44% of our estimated net proved reserves volumes were classified as proved undeveloped as of December 31, 2018. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Our acquisition strategy will subject us to certain risks associated with the inherent uncertainty in evaluating properties for which we have limited information.

We intend to expand our operations in part through acquisitions. Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not economically feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections are often not performed on properties being acquired, and environmental matters, such as subsurface contamination, are not necessarily observable even when an inspection is undertaken.

Any acquisition involves other potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues and costs;
- a decrease in our liquidity by using a significant portion of our cash from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;

• the ultimate value of any contingent consideration agreed to be paid in an acquisition;

• dilution to shareholders if we use equity as consideration for, or to finance, acquisitions;

• the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;

•an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; and

•an increase in our costs or a decrease in our revenues associated with any potential royalty owner or landowner claims or disputes.

Contingent consideration payable pursuant to existing or future agreements could adversely impact our results of operation, cash flows and financial condition.

We have in the past, and may in the future, enter into agreements that provide for the potential payment by us of additional consideration depending on actual performance against established criteria. Recent agreements of this type include the acquisition agreements we entered into during 2018 in connection with the Pivotal Acquisition and the W Energy Acquisition (see Note 3 to our financial statements), as well as certain exchange agreements we entered into during 2018 with holders of our senior unsecured notes (see Note 4 to our financial statements), each of which require us to pay additional consideration to the counterparties if our stock price does not trade at or above agreed upon levels over specified periods. The liabilities associated with the potential additional consideration under the Pivotal and W Energy acquisition agreements are recognized at fair value and recorded as contingent consideration liabilities on the Company's condensed balance sheets. The liabilities associated with the potential additional consideration under the debt exchange agreements are recognized at fair value and recorded as debt exchange derivative liabilities on the Company's condensed balance sheets. These fair values may change significantly over time, with the fair value of these liabilities generally decreasing if our average stock price increases or increasing if our average stock price decreases, and such changes are recorded in other income (expense) on the Company's condensed statement of operations. We are permitted in certain circumstances to settle amounts owed in either cash or shares of common stock. Regardless, changes in the fair value of these liabilities, and amounts we are required to pay over time, could adversely impact our results of operation, cash flows and financial condition.

The loss of any member of our management team, upon whose knowledge, relationships with industry participants, leadership and technical expertise we rely could diminish our ability to conduct our operations and harm our ability to execute our business plan.

Our success depends heavily upon the continued contributions of those members of our management team whose knowledge, relationships with industry participants, leadership and technical expertise would be difficult to replace. In particular, our ability to successfully acquire additional properties, to increase our reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements depends on developing and maintaining close working relationships with industry participants. In addition, our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment is dependent on our management team's knowledge and expertise in the industry. To continue to develop our business, we rely on our management team's knowledge and expertise in the industry and will use our management team's relationships with industry participants to enter into strategic relationships, which may take the form of joint ventures with other private parties and contractual arrangements with other oil and natural gas companies.

The members of our management team may terminate their employment with our company at any time. If we were to lose members of our management team, we may not be able to replace the knowledge that they possess. In addition, we may not be able to establish or maintain strategic relationships with industry participants. If we were to lose the services of the members of our management team, our ability to conduct our operations and execute our business plan could be materially harmed.

Deficiencies of title to our leased interests could significantly affect our financial condition.

We typically do not incur the expense of a title examination prior to acquiring oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights. If an examination of the title history of a property reveals that an oil or natural gas lease or other developed rights have been purchased in error from a person who is not the owner of the mineral interest desired, our interest would substantially decline in value or be eliminated. In such cases, the amount paid for such oil or natural gas lease or leases or other developed rights may be lost. It is generally our practice not to incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Rather, we typically rely upon the judgment of oil and natural gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental or county clerk's office before attempting to acquire a lease or other developed rights in a specific mineral interest.

Prior to drilling an oil or natural gas well, however, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed oil or natural gas well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, such as obtaining affidavits of heirship or causing an estate to be administered. Such curative work entails expense, and the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion. Furthermore, title issues may arise at a later date that were not initially detected in any title review or examination. Any one or more of the foregoing could require us to reverse revenues previously recognized and potentially negatively affect our cash flows and results of operations. Our failure to obtain perfect title to our leaseholds may adversely affect our current production and reserves and our ability in the future to increase production and reserves.

Competition may limit our ability to obtain rights to explore and develop oil and natural gas reserves.

The oil and natural gas industry is highly competitive. Other oil and natural gas companies may seek to acquire oil and natural gas leases and other properties and services we will need to operate our business in the areas in which we expect to operate. Additionally, other companies engaged in our line of business may compete with us from time to time in obtaining capital from investors. Competitors include larger companies which, in particular, may have access to greater resources, may be more successful in the recruitment and retention of qualified employees and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests. If we are unable to compete effectively or respond adequately to competitive pressures, our results of operation and financial condition may be materially adversely affected.

Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

The Williston Basin crude oil business environment has historically been characterized by periods when oil production has surpassed local transportation and refining capacity, resulting in substantial discounts in the price received for crude oil versus prices quoted for WTI crude oil. Although additional Williston Basin transportation takeaway capacity has been added over the last several years, production also increased substantially during the same period. The increased production coupled with delays in rail car arrivals and commissioning of rail loading facilities has caused price differentials to significantly increase at times.

Crude oil from the Bakken/Three Forks formations may pose unique hazards that may have an adverse effect on our operations.

In 2015, the U.S. Department of Transportation ("USDOT") concluded that crude oil from the Bakken/ Three Forks formations has a higher volatility than most other U.S. crude oil and thus is more ignitable and flammable. Based on that information, and several fires involving rail transportation of crude oil, USDOT issued a rail safety rule in 2015 that included new construction standards for rail tank cars constructed after October 1, 2015. The final rule created a new North American tank car standard known as the DOT Specification 117 ("DOT-117") rail car with thicker steel and redesigned bottom outlet valves, among other improvements over the then-standard DOT Specification 111 ("DOT-111") tank car. The final rule established a schedule for retrofitting or replacing older tank cars and included mandates for using electronically controlled pneumatic ("ECP") braking systems and for performing routing analyses, among other requirements. In December 2017, the USDOT repealed the ECP provisions of the 2015 rail safety rule. USDOT issued a final rule in 2019 expanding the applicability of oil spill response plans for high-hazard flammable trains. In addition, the rail industry has adopted increased precautions for crude shipments. Any new restrictions that significantly affect transportation of crude oil production could materially and adversely affect our financial condition, results of operations and cash flows.

Our business involves the selling and shipping by rail of crude oil, including from the Bakken shale, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as potential regulatory changes that may adversely impact our business, financial condition or results of operations.

A portion of our crude oil production is transported to market centers by rail. Derailments in North America of trains transporting crude oil have caused various regulatory agencies and industry organizations, as well as federal, state and municipal governments, to focus attention on transportation by rail of flammable materials. Transportation safety regulators in the United States and Canada are concerned that crude oil from the Bakken shale may be more flammable than crude oil from other producing regions and are investigating that issue and are also considering changes to existing regulations to address those possible risks, as noted directly above. In May 2015, USDOT's Pipelines and Hazardous Materials Safety Administration ("PHMSA") adopted a final rule that, among other things, imposed a new and enhanced tank car design standard for certain tank cars carrying crude oil and ethanol, a phase out by as early as January 2018 for older DOT-111 tank cars that were not retrofitted, and a classification and testing program for unrefined petroleum based products, including crude oil. The rule also included new operational requirements such as routing analyses, speed restrictions and enhanced braking controls. However, in December 2017, the USDOT repealed the enhanced braking control provisions of the May 2015 rail safety rule. USDOT is expected to issue a final rule in 2018 expanding the applicability of oil spill response plans for high-hazard flammable trains. Transport Canada has also issued legal requirements that align with the rule adopted by PHMSA, including standards relating to train speed restrictions, route risk analyses and a phase out of non-compliant DOT-111 tank cars.

Any changes to existing laws and regulations, or promulgation of new laws and regulations, including any voluntary measures by the rail industry, that result in new requirements for the design, construction or operation of tank cars used to transport crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

To the extent that new regulations require design changes or other modifications of tank cars, we may incur significant constraints on transportation capacity during the period while tank cars are being retrofitted or newly constructed to comply with the new regulations. In addition, any derailment of crude oil from the Bakken shale involving crude oil that we have sold or are shipping may result in claims being brought against us that may involve significant liabilities. Although we believe that we are adequately insured against such events, we cannot assure you that our insurance policies will cover the entirety of any damages that may arise from such an event.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. If our production becomes shut-in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We depend on computer and telecommunications systems, and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed or may develop proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. It is possible that we, or these third parties, could incur interruptions from cyber security attacks, computer viruses or malware, or that third party service providers could cause a breach of our data. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties for our computing and communications infrastructure or any other interruptions to, or breaches of, our information systems could lead to data corruption, communication interruption, loss of sensitive or confidential information or otherwise significantly disrupt our business operations. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. To our knowledge we have not experienced any material losses relating to cyber attacks; however, there can be no assurance that we will not suffer material losses in the future either as a result of an interruption to or a breach of our systems or those of our third party vendors and service providers.

We are subject to litigation and adverse outcomes in such litigation could have an adverse effect on our financial condition.

We are, and from time to time may become, subject to litigation and various legal proceedings, including stockholder derivative suits, class action lawsuits and other matters, that involve claims for substantial amounts of money or for other relief or that might necessitate changes to our business or operations. For example, in August 2016, Jeffrey Fries, individually and on behalf of all others similarly situated, filed a class action complaint in the United States District Court for the Southern District of New York against the Company. The complaint was amended in January 2018 and alleged violations of the Exchange Act, and Rule 10b-5 thereunder. Although this particular complaint was ultimately dismissed, the defense of these actions may be both time consuming and expensive. We evaluate these litigation claims and legal proceedings to assess the likelihood of unfavorable outcomes and to estimate, if possible, the amount of potential losses. Based on these assessments and estimates, we may establish reserves and/or disclose the relevant litigation claims or legal proceedings, as and when required or appropriate. These assessments and estimates are based on information available to management at the time of such assessment or estimation and involve a significant amount of judgment. As a result, actual outcomes or losses could differ materially from those envisioned by our current assessments and estimates. Our failure to successfully defend or settle any litigation or legal proceedings could result in liability that, to the extent not covered by our insurance, could have an adverse effect on our business, financial condition and results of operations.

Allegations and proceedings concerning our founder, chairman emeritus and president could generate negative publicity for us, harm our reputation and adversely affect our business.

Our founder, chairman emeritus and president, Michael Reger, has played a key role in the development and success of our business. Mr. Reger has been the subject of proceedings and lawsuits in connection with alleged securities violations as a co-founder of Dakota Plains Holdings, Inc. These proceedings included administrative proceedings instituted by the SEC for alleged federal securities laws violations related to Mr. Reger's alleged failure to adequately disclose his ownership and control of Dakota Plains Holdings, Inc., which Mr. Reger settled in October 2016 without admitting or denying the SEC's findings. Any future proceedings or allegations against Mr. Reger could result in negative press speculation, as well as adverse perceptions of him or us among the public, our industry or in the capital markets, any of which could have a material adverse effect on our business.

Our derivative activities expose us to potential regulatory risks.

The Federal Trade Commission ("FTC"), Federal Regulatory Commission ("FERC") and the Commodities Futures Trading Commission ("CFTC") have statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to derivative activities that we undertake with respect to oil, natural gas, NGLs, or other energy commodities, we are required to observe the market-related regulations enforced by these agencies. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

Legislative and regulatory developments could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

In July of 2010, the United States Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"), which contains measures aimed at increasing the transparency and stability of the over-the-counter ("OTC") derivatives market and preventing excessive speculation. In November 2013, the CFTC re-proposed implementing regulations imposing position limits for certain physical commodity contracts in the major energy markets and economically equivalent futures, options and swaps, with exemptions for certain bona fide hedging positions. The CFTC's initial position limit rules were vacated by a federal court in 2012. It is not clear when the re-proposed rules on position limits would become effective. CFTC rules under the Dodd-Frank Act also may impose clearing and trade execution requirements in connection with our derivatives activities, although currently those requirements do not extend to derivatives based on physical commodities in the energy markets and some or all of our derivatives activities may be exempt from such requirements based on our non-financial end-user status.

Regulations issued under the Dodd-Frank Act also may require certain counterparties to our derivative instruments to spin off some of their derivative activities to a separate entity, which may not be as creditworthy as the current counterparty. The final rules are being phased in over time depending on the finalization of certain other rules to be promulgated jointly by the CFTC and the SEC. The legislation and regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. We maintain an active hedging program related to oil price risks. The Dodd-Frank Act and rules and regulations thereunder could reduce trading positions and the market-making activities of our counterparties. If we reduce our use of derivatives as a result of legislation and regulations or any resulting changes in the derivatives markets, 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 or to make payments on our debt obligations. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

Our business is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our operational interests, as operated by our third-party operating partners, are regulated extensively at the federal, state, tribal and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, our company (either directly or indirectly through our operating partners) could also be liable for personal injuries, property and natural resource damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our business and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we do business includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our business and limit the quantity of natural gas we may produce and sell. A major risk inherent in the drilling plans in which we participate is the need for our operators to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on the development of our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our profitability. At this time, we cannot predict the effect of this increase on our results of operations. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff.

Environmental risks may adversely affect our business.

All phases of the oil and natural gas business can present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. There is risk of incurring significant environmental costs and liabilities as a result of the handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to our business, and historical operations and waste disposal practices. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, loss of our leases, incurrence of investigatory or remedial obligations and the imposition of injunctive relief.

Environmental legislation is evolving in a manner we expect may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge, regardless of whether we were responsible for the release or contamination and regardless of whether our operating partners met previous standards in the industry at the time they were conducted. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of operations on our properties. The application of environmental laws to our business may cause us to curtail production or increase the costs of our production, development or exploration activities.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is used extensively by our third- party operating partners. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Any federal or state legislative or regulatory changes with respect to hydraulic fracturing could cause us to incur substantial compliance costs or result in operational delays, and the consequences of any failure to comply by us or our third-party operating partners could have a material adverse effect on our financial condition and results of operations.

In addition, in response to concerns relating to recent seismic events near underground disposal wells used for the disposal by injection of flowback and produced water or certain other oilfield fluids resulting from oil and natural gas activities (so-called "induced seismicity"), regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. States may, from time to time, develop and implement plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. These developments could result in additional regulation and restrictions on the use of injection wells by our operators to dispose of flowback and produced water and certain other oilfield fluids. Increased regulation and attention given to induced seismicity also could lead to greater opposition to, and litigation concerning, oil and natural gas activities utilizing injection wells for waste disposal. Until such pending or threatened legislation or regulations are finalized and implemented, it is not possible to estimate their impact on our business.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

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

Various state governments and regional organizations have considered enacting new legislation and promulgating new regulations governing or restricting the emission of "greenhouse gases" ("GHG") from stationary sources such as our equipment and operations. At the federal levels, the EPA has determined that emissions of certain GHG present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on its findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHG.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHG, though it is yet to do so, and almost one-half of the states have already taken legal measures to reduce emissions of GHG primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of GHGs. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG reduction goal. As the number of GHG emission allowances declines each year, the cost or value of such allowances is expected to escalate significantly.

Additionally, in December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris Agreement" was signed by the United States in April 2016 and entered in force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions. In August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may reenter the Paris Agreement or separately negotiated agreement are unclear at this time.

The adoption of legislation or regulatory programs to reduce emissions of GHG could require our third-party operating partners, and indirectly us, to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas produced by our operational interests. Consequently, legislation and regulatory programs to reduce emissions of GHG could have an adverse effect on our business, financial condition and results of operations.

Regulation of GHG emissions could also result in reduced demand for our production, as oil and natural gas consumers seek to reduce their own GHG emissions. Any regulation of GHG emissions, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could have a material adverse effect on our business, results of operations and financial condition. In addition, to the extent climate change results in more severe weather and significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic effects, our own, our third-party operating partners or our customers' operations may be disrupted, which could result in a decrease in our available products or reduce our customers' demand for our products.

Further, there have been various legislative and regulatory proposals at the federal and state levels to provide incentives and subsidies to (i) shift more power generation to renewable energy sources and (ii) support technological advances to drive less energy consumption. These incentives and subsidies could have a negative impact on oil, natural gas and NGL consumption.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Decommissioning costs are unknown and may be substantial. Unplanned costs could divert resources from other projects.

We may become responsible for costs associated with plugging, abandoning and reclaiming wells, pipelines and other facilities that we use for production of oil and natural gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as "decommissioning." We accrue a liability for decommissioning costs associated with our wells, but have not established any cash reserve account for these potential costs in respect of any of our properties. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair our ability to focus capital investment in other areas of our business.

Our revolving credit facility and the indenture governing our senior secured notes contain operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit facility and the indenture governing our senior secured notes contain, and any future indebtedness we incur may contain, a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

•declare or pay any dividend or make any other distributions on, purchase or redeem our equity interests or purchase or redeem certain debt;

•make loans or certain investments;

•make certain acquisitions and investments;

•incur or guarantee additional indebtedness or issue certain types of equity securities;

•incur liens;

•transfer or sell assets;

•create subsidiaries

•consolidate, merge or transfer all or substantially all of our assets; and

•engage in transactions with our affiliates.

In addition, the revolving credit facility requires us to maintain compliance with certain financial covenants and other covenants. As a result of these covenants, we could be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the covenants and restrictions may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our revolving credit facility or any future indebtedness could result in an event of default under our revolving credit facility or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. If an event of default under our revolving credit facility occurs and remains uncured, the lenders thereunder:

•would not be required to lend any additional amounts to us;

•could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;

•may have the ability to require us to apply all of our available cash to repay these borrowings; and

•may prevent us from making debt service payments under our other agreements.

An event of default or an acceleration under our revolving credit facility could result in an event of default and an acceleration under other existing or future indebtedness, including the indenture governing the senior secured notes. Conversely, an event of default or an acceleration under any other existing or future indebtedness could result in an event of default and an acceleration under our revolving credit facility. In addition, our obligations under the revolving credit facility and the senior secured notes are collateralized by perfected liens and security interests on substantially all of our assets and if we default thereunder the lenders could seek to foreclose on our assets.

Our revolving credit facility limits the amounts we can borrow up to a borrowing base amount, which the administrative agent in good faith and in accordance with its usual and customary oil and gas lending criteria as they exist at the particular time will determine and be approved by the required lenders or all lenders on a semi- annual basis based upon projected revenues from our natural gas properties pursuant to engineering reports provided to the administrative agent. In addition to the scheduled redeterminations, we, the administrative agent and the required lenders have the right to request one additional borrowing base redetermination during each period between scheduled redeterminations. Any increase in the borrowing base requires the consent of all lenders. Subject to customary grace periods, we will be required to repay outstanding borrowings in excess of the borrowing base. The borrowing base will also automatically decrease upon the issuance of certain debt, the sale or other disposition of certain assets in excess of 5% of the borrowing base then in effect and the early termination of certain swap agreements.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

•refinancing or restructuring our debt;

•selling assets;

•reducing or delaying capital investments; or

•seeking to raise additional capital.

However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations, or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

The inability of one or more of our operating partners to meet their obligations to us may adversely affect our financial results.

Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production, which operating partners market on our behalf to energy marketing companies, refineries and their affiliates.

We are subject to credit risk due to the concentration of our oil and natural gas receivables with a limited number of operating partners. This concentration may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. A low commodity price environment may strain our operating partners, which could heighten this risk. The inability or failure of our operating partners to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our revolving credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

We may be able to incur substantially more debt. This could further exacerbate the risks associated with our substantial indebtedness.

We may be able to incur substantial additional indebtedness in the future, subject to certain limitations, including under our revolving credit facility, our senior secured notes and under any future debt agreements. If new debt is added to our current debt levels, the related risks that we now face could increase. Our level of indebtedness could, for instance, prevent us from engaging in transactions that might otherwise be beneficial to us or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations, and business prospects.

Our level of indebtedness could affect our operations in several ways, including the following:

•require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;

•increase our vulnerability to economic downturns and adverse developments in our business;

•limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;

•place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;

•place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing then indebtedness;

•limit our ability to deduct our net interest expense; and

•make it more difficult for us to satisfy our obligations under the instruments governing our indebtedness and increase the risk that we may default on our debt obligations.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We depend on our revolving credit facility for future capital needs, because we use operating cash flows for investing activities and borrow as needed. We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough money, we may be required to refinance all or part of our existing debt, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all. Our ability to comply with the financial and other restrictive covenants in our indebtedness will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could materially and adversely affect our business, financial condition and results of operations.

Our certificate of incorporation, bylaws, and Delaware state law contain provisions that may have the effect of delaying or preventing a change in control and may adversely affect the market price of our capital stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without any further vote or action by our shareholders. The rights of the holders of our common stock will be subject to the rights of the holders of any preferred stock that may be issued in the future. The issuance of preferred stock could delay, deter or prevent a change in control and could adversely affect the voting power or economic value of our shares.

In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our shareholders, including, among others, limitations on the ability of our stockholders to call special meetings, limitations on the ability of our shareholders to act by written consent, and advance notice provisions for shareholders proposals and nominations for elections to the board of directors to be acted upon at meetings of shareholders.

Delaware law generally prohibits us from engaging in any business combination with any “interested shareholder,” meaning generally that a shareholder who owns 15% or more of our stock cannot acquire us for a period of three years from the date such shareholder became an interested shareholder, unless various conditions are met.

The availability of shares for sale in the future could reduce the market price of our common stock.

Our board of directors has the authority, without action or vote of our stockholders, to issue all or any part of our authorized but unissued shares of common stock. In the future, we may issue securities to raise cash for acquisitions, as consideration in acquisitions to pay down debt, to fund capital expenditures or general corporate expenses, in connection with the exercise of stock options or to satisfy our obligations under our incentive plans. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

Because we do not currently pay, and are subject to restriction on paying dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We have never paid any cash dividends on our common stock. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in the instruments governing our indebtedness restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. *Properties*

Estimated Net Proved Reserves

The table below summarizes our estimated net proved reserves at December 31, 2018, 2017 and 2016 based on reports prepared by Cawley, Gillespie & Associates, Inc. ("Cawley"), our independent reserve engineers for the year ending December 31, 2018 and Ryder Scott, LP ("Ryder Scott"), our former independent reserve engineers for the years ending December 31, 2017 and 2016. In preparing its reports, Cawley and Ryder Scott, respectively, evaluated properties representing all of our proved reserves at December 31, 2018, 2017 and 2016 in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities. Our estimated net proved reserves in the table below do not include probable or possible reserves and do not in any way include or reflect our commodity derivatives.

	December 31, 2018		**December 31, 2017**		**December 31, 2016**	
	Proved Reserves (MBoe)(1)	**% of Total**	**Proved Reserves (MBoe)(2)**	**% of Total**	**Proved Reserves (MBoe)(3)**	**% of Total**
SEC Proved Reserves:						
Developed	76,216	56%	46,345	61%	37,713	70%
Undeveloped	59,268	44	29,487	39	16,368	30
Total Proved Properties	135,484	100%	75,832	100%	54,081	100%

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(1) The table above values oil and natural gas reserve quantities as of December 31, 2018 assuming constant realized prices of $61.23 per barrel of oil and $4.50 per Mcf of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period, after adjustment to reflect applicable transportation and quality differentials.
(2) The table above values oil and natural gas reserve quantities as of December 31, 2017 assuming constant realized prices of $45.90 per barrel of oil and $3.34 per Mcf of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period, after adjustment to reflect applicable transportation and quality differentials.
(3) The table above values oil and natural gas reserve quantities as of December 31, 2016 assuming constant realized prices of $35.24 per barrel of oil and $1.67 per Mcf of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period, after adjustment to reflect applicable transportation and quality differentials.

Estimated net proved reserves at December 31, 2018 were 135,484 MBoe, a 79% increase from estimated net proved reserves of 75,832 MBoe at December 31, 2017. The increase in 2018 total proved reserves was primarily due to the impact of our 2018 acquisitions, as well as higher commodity prices and higher activity levels in 2018 as compared to 2017, which also increased both the number of undeveloped drilling locations and the expected productive life of economic locations reflected in our 2018 proved reserve estimates. Higher commodity prices and increased development activity in 2018 led to an increase in our capital spending. As a result of the higher activity levels and our 2018 acquisitions, the number of proved undeveloped wells included in the reserves was increased from 52.1 net wells in 2017 to 97.9 net wells in 2018.

Estimated net proved reserves at December 31, 2017 were 75,832 MBoe, a 40% increase from estimated net proved reserves of 54,081 MBoe at December 31, 2016. The increase in 2017 total proved reserves was primarily due to the impact of higher commodity prices in 2017 as compared to 2016, which also increased both the number of undeveloped drilling locations and the expected productive life of economic locations reflected in our 2017 proved reserve estimates. Higher commodity prices and development activity in 2017 led to an increase in our capital spending. As a result of the higher activity levels, the number of proved undeveloped wells included in the reserves was increased from 32.6 net wells in 2016 to 52.1 net wells in 2017.

The following table sets forth summary information by reserve category with respect to estimated proved reserves at December 31, 2018:

	SEC Pricing Proved Reserves[1]					
	Reserve Volumes				**PV-10(3)**	
Reserve Category	**Oil (MBbls)**	**Natural Gas (MMcf)**	**Total (MBoe)(2)**	**%**	**Amount (In thousands)**	**%**
PDP Properties	55,426	73,266	67,637	50%	$ 1,310,931	60%
PDNP Properties	7,071	9,048	8,579	6	206,113	10
PUD Properties	50,476	52,752	59,268	44	663,184	30
Total	112,973	135,066	135,484	100%	$ 2,180,228	100%

[1] The SEC Pricing Proved Reserves table above values oil and natural gas reserve quantities and related discounted future net cash flows as of December 31, 2018 based on average prices of $65.56 per barrel of oil and $3.10 per MMbtu of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per MMbtu of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period. The average resulting price used as of December 31, 2018, after adjustment to reflect applicable transportation and quality differentials, was $61.23 per barrel of oil and $4.50 per Mcf of natural gas.
[2] Boe are computed based on a conversion ratio of one Boe for each barrel of oil and one Boe for every 6,000 cubic feet (i.e., 6 Mcf) of natural gas.
[3] Pre-tax PV10%, or “PV-10,” may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP measure. See “Reconciliation of PV-10 to Standardized Measure” below.

The table above assumes prices and costs discounted using an annual discount rate of 10% without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or federal income taxes. The information in the table above does not give any effect to or reflect our commodity derivatives.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure for proved reserves calculated using SEC pricing. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves or for reserves calculated using prices other than SEC prices. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table reconciles the pre-tax PV10% value of our SEC Pricing Proved Reserves as of December 31, 2018 to the Standardized Measure of discounted future net cash flows.

SEC Pricing Proved Reserves (in thousands)		
Standardized Measure Reconciliation		
Pre-Tax Present Value of Estimated Future Net Revenues (Pre-Tax PV10%)	$	2,180,228
Future Income Taxes, Discounted at 10%(1)	(300,585)	
Standardized Measure of Discounted Future Net Cash Flows	$	1,879,643

(1) The expected tax benefits to be realized from utilization of the net operating loss and tax credit carryforwards are used in the computation of future income tax cash flows. As a result of available net operating loss carryforwards and the remaining tax basis of our assets at December 31, 2018, our future income taxes were significantly reduced.

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner. As a result, estimates of proved reserves may vary depending upon the engineer estimating the reserves. Further, our actual realized price for our oil and natural gas is not likely to average the pricing parameters used to calculate our proved reserves. As such, the oil and natural gas quantities and the value of those commodities ultimately recovered from our properties will vary from reserve estimates.

Additional discussion of our proved reserves is set forth under the heading “Supplemental Oil and Gas Information - Unaudited” to our financial statements included later in this report.

Proved Undeveloped Reserves

At December 31, 2018, we had approximately 59.3 MMBoe of proved undeveloped reserves as compared to 29.5 MMBoe at December 31, 2017. A reconciliation of the change in proved undeveloped reserves during 2018 is as follows:

	MMBoe
Estimated Proved Undeveloped Reserves at 12/31/2017	29.5
Converted to Proved Developed Through Drilling	(8.2)
Added from Extensions and Discoveries	26.4
Purchases of Minerals in Place	10.3
Removed for 5-Year Rule	(1.8)
Revisions	3.1
Estimated Proved Undeveloped Reserves at 12/31/2018	59.3

During 2018, we significantly grew our asset base through acquisitions. In addition, commodity prices for crude oil, NGL and natural gas increased from the prior year, which resulted in higher development capital spending during 2018. We expect to maintain similar levels of development capital spending in 2019. As a result, we have increased the proportion of our reserves that have historically been categorized as PUD. This is driven by the current economic price environment, coupled with our improved liquidity, which increases the number of PUD locations that we have reasonable certainty to believe will be developed during the five-year time horizon.

Our future development drilling program includes the drilling of approximately 97.9 proven undeveloped net wells before the end of 2023 at an estimated cost of $736.3 million. Our development plan for drilling proved undeveloped wells calls for the drilling of 30.9 net wells during 2019 (includes 9.1 net wells drilled at December 31, 2018, but classified as proved undeveloped due to Cawley's internal guidelines which require greater than 50% of total costs to be incurred to be classified as developed), 20.3 net wells during 2020, 18.0 net wells during 2021, 15.6 net wells during 2022 and 13.1 net wells during 2023 for a total of 97.9 net wells. We expect that our proved undeveloped reserves will continue to be converted to proved developed producing reserves as additional wells are drilled including our acreage. All locations comprising our remaining proved undeveloped reserves are forecast to be drilled within five years from initially being recorded in accordance with our development plan.

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At December 31, 2018, the PV-10 value of our proved undeveloped reserves amounted to 30% of the PV-10 value of our total proved reserves. Although our 2018 producing property additions exceeded our 5-year average development plan, there are numerous uncertainties. The development of these reserves is dependent upon a number of factors which include, but are not limited to: financial targets such as drilling within cash flow or reducing debt, drilling of obligatory wells, satisfactory rates of return on proposed drilling projects, and the levels of drilling activities by operators in areas where we hold leasehold interests. During 2018, we increased our development capital spending by 87% compared to 2017 in response to the improving commodity price environment. If a lower commodity price environment reoccurs, we may seek to reduce our development spending. While lower commodity prices could reduce our future borrowing capacity (we had $2.4 million of cash and committed borrowing availability of $285.0 million under our revolving credit facility at December 31, 2018), with 60% of the PV-10 value of our total proved reserves supported by producing wells, we believe we will have sufficient cash flows and adequate liquidity to complete our development plan.

At December 31, 2018, we had spent a total of $88.3 million related to the development of proved undeveloped reserves, which resulted in the conversion of 8.2 MMBoe of proved undeveloped reserves as of December 31, 2017 to proved developed reserves as of December 31, 2018. Proved developed property additions in 2018 also included 6.2 MMBoe from the conversion of previously undeveloped locations that were not booked in our December 31, 2017 proved undeveloped reserves (the related development costs incurred at December 31, 2018 were $84.4 million). Additionally, our proved undeveloped reserves at December 31, 2018 included 5.7 MMBoe for net wells that had commenced drilling activities but remained classified as undeveloped reserves due to Cawley's internal guidelines which require greater than 50% of the total costs to have been incurred in order to be classified as proved developed (the related development costs incurred at December 31, 2018 were $28.3 million).

In 2018, we also added 26.4 MMBoe of proved undeveloped reserves primarily in our North Dakota areas of operations as a result of higher commodity prices and increased well performance and development activity in the Williston Basin. The SEC-prescribed commodity prices (after adjustment for transportation, quality and basis differentials) were $15.33 higher per barrel of oil and $1.16 higher per Mcf of natural gas at year-end 2018 as compared to year-end 2017. Additionally, we had positive performance revisions of 3.1 MMBoe due to improved well performance from enhanced completion techniques. Our acquisitions of oil and natural gas properties in 2018 resulted in 10.3 MMBoe of additional proved undeveloped reserves. We also removed 1.8 MMBoe of proved undeveloped reserves due to the SEC-prescribed 5-year rule.

Proved Reserves Sensitivity by Price Scenario

The SEC disclosure rules allow for optional reserves sensitivity analysis, such as the sensitivity that oil and natural gas reserves have to price fluctuations. We have chosen to compare our proved reserves from the 2018 SEC case to one alternate pricing case, which uses a flat pricing deck of $55.00 per Bbl for oil and $2.70 per MMbtu for natural gas (the “$55 Flat Case”). The sensitivity scenario was not audited by a third party. In the sensitivity scenario, all factors other than the commodity price assumptions have been held constant with the SEC case, including the number of proved undeveloped locations, drill schedules and operating costs assumptions. This sensitivity is only meant to demonstrate the impact that changing commodity prices may have on estimated proved reserves and PV-10 and there is no assurance this outcome will be realized. The table below shows our proved reserves utilizing the 2018 SEC case compared with the $55 Flat Case.

	Price Cases	
	SEC Case(1)	**$55 Flat Case(2)**
Net Proved Reserves (December 31,		

2018)				
Oil (MBbl)				
Developed	62,497		60,229	
Undeveloped	50,476		47,774	
Total	112,973		108,003	
Natural Gas (MMcf)				
Developed	82,315		79,036	
Undeveloped	52,752		49,531	
Total	135,067		128,567	
Total Proved Reserves (MBOE)	135,484		129,430	
Pre-tax PV10% (in thousands) (3)	$	2,180,228	$	1,593,293

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(1) Represents reserves based on pricing prescribed by the SEC. The unescalated twelve month arithmetic average of the first day of the month posted prices were adjusted for transportation and quality differentials to arrive at prices of $61.23 per Bbl for oil and $4.50 per Mcf for natural gas. Production costs were held constant for the life of the wells.
(2) Prices based on $55.00 per Bbl for oil and $2.70 per MMbtu for natural gas, which were then adjusted for transportation and quality differentials to arrive at prices of $50.66 per Bbl for oil and $3.92 per Mcf for natural gas. Production costs and the future development drilling program were both held constant with the SEC case.
(3) Pre-tax PV10%, or PV-10, may be considered a non-GAAP financial measure. See “Reconciliation of PV-10 to Standardized Measure” above for a reconciliation of the PV-10 of our SEC Case proved reserves to the Standardized Measure. GAAP does not prescribe a corresponding measure for PV-10 of proved reserves based on other than SEC prices. As a result, it is not practicable for us to reconcile the PV-10 of our proved reserves based on the $55 Flat Case.

Independent Petroleum Engineers

We have utilized Cawley, Gillespie & Associates, Inc. (“Cawley”), an independent reserve engineering firm, as our third-party engineering firm. The selection of Cawley was approved by our Audit Committee. Cawley is a reservoir-evaluation consulting firm who evaluates oil and natural gas properties and independently certifies petroleum reserves quantities for various clients throughout the United States. Cawley has substantial experience calculating the reserves of various other companies with operations targeting the Bakken and Three Forks formations and, as such, we believe Cawley has sufficient experience to appropriately determine our reserves. Cawley utilizes proprietary technology, systems and data to calculate our reserves commensurate with this experience. The reports of our estimated proved reserves in their entirety are based on the information we provide to them. Cawley is a Texas Registered Engineering Firm (F-693). Our primary contact at Cawley is Todd Brooker, President. Mr. Brooker is a State of Texas Licensed Professional Engineer (License #83462). He is also a member of the Society of Petroleum Engineers.

In accordance with applicable requirements of the SEC, estimates of our net proved reserves and future net revenues are made using average prices at the beginning of each month in the 12-month period prior to the date of such reserve estimates and are held constant throughout the life of the properties (except to the extent a contract specifically provides for escalation).

The reserves set forth in the Cawley report for the properties are estimated by performance methods or analogy. In general, reserves attributable to producing wells and/or reservoirs are estimated by performance methods such as decline curve analysis which utilizes extrapolations of historical production data. Reserves attributable to non-producing and undeveloped reserves included in our report are estimated by analogy. The estimates of the reserves, future production, and income attributable to properties are prepared using the economic software package Aries for Windows, a copyrighted program of Halliburton.

To estimate economically recoverable oil and natural 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 demonstrated to be economically producible based on existing economic conditions including the prices and costs at which economic productivity from a reservoir is to be determined as of the effective date of the report. With respect to the property interests we own, 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, production taxes, recompletion and development costs and product prices are based on the SEC regulations, geological maps, well logs, core analyses, and pressure measurements.

The reserve data set forth in the Cawley report represents only estimates, and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the actual revenues and costs could be more or less than the estimated amounts. Moreover, estimates of reserves may increase or decrease as a result of future operations.

Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values, including many factors beyond our control. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, prevailing oil and natural gas prices, operating costs and other factors. The revisions may be material. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. Our estimated net proved reserves, included in our SEC filings, have not been filed with or included in reports to any other federal agency. See “Item 1A. Risk Factors – Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.”

Internal Controls Over Reserves Estimation Process

We utilize a third-party reservoir engineering firm, as our independent reserves evaluator for 100% of our reserves base. In addition, we employ an internal reserve engineering department which is led by our Vice President of Engineering, who is responsible for overseeing the preparation of our reserves estimates. Our senior internal reserve engineer has a B.S. in petroleum engineering from Montana Tech, has over thirteen years of oil and gas experience on the reservoir side, and has experience working for large independent and financial firms on projects and acquisitions.

Our technical team meets with our independent third-party engineering firm to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data into our reserves evaluation software as well as management review, such as, but not limited to the following:

•Comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input in our reserves database;

•Review of working interests and net revenue interests in our reserves database against our well ownership system;

•Review of historical realized prices and differentials from index prices as compared to the differentials used in our reserves database;

•Review of updated capital costs prepared by our operations team;

•Review of internal reserve estimates by well and by area by our internal reservoir engineer;

•Discussion of material reserve variances among our internal reservoir engineer and our executive management; and

•Review of a preliminary copy of the reserve report by executive management.

Production, Price and Production Expense History

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Oil supply in the United States has grown dramatically over the past few years, and the supply of oil could impact oil prices in the United States if the supply outstrips domestic demand. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth information regarding our oil and natural gas production, realized prices and production costs for the periods indicated. For additional information on price calculations, please see information set forth in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	Years Ended December 31,		
	2018	2017	2016
Net Production:			
Oil (Bbl)	7,790,182	4,537,295	4,325,919
Natural Gas and NGLs (Mcf)	9,224,766	5,187,886	4,026,899
Total (Boe)	9,327,643	5,401,943	4,997,069
Average Sales Prices:			
Oil (per Bbl)	$ 57.78	$ 45.09	$ 35.22
Effect of Gain (Loss) on Settled Derivatives on Average Price (per Bbl)	(2.94)	0.83	14.22
Oil Net of Settled Derivatives (per Bbl)	54.84	45.92	49.44
Natural Gas and NGLs (per Mcf)	4.74	3.74	1.82
Realized Price on a Boe Basis Including all Realized Derivative Settlements	50.50	42.16	44.27
Average Costs:			
Production Expenses (per Boe)	$ 7.15	$ 9.21	$ 9.14

Drilling and Development Activity

The following table sets forth the number of gross and net productive and non-productive wells drilled in the years ended December 31, 2018, 2017 and 2016. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated. We have classified all wells drilled to-date targeting the Bakken and Three Forks formations as development wells.

December 31,

	2018		**2017**		**2016**	
	Gross	**Net (1)**	**Gross**	**Net**	**Gross**	**Net**
Exploratory Wells:						
Oil	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—
Non-Productive	—	—	—	—	—	—
Development Wells:						
Oil	505	31.2	354	16.9	294	10.7
Natural Gas	—	—	—	—	—	—
Non-Productive	—	—	—	—	—	—
Total Productive Exploratory and Development Wells	505	31.2	354	16.9	294	10.7

(1) 2018 totals do not include an additional 65.8 net wells from acquisitions which were already producing when acquired.

The following table summarizes our cumulative gross and net productive oil wells by state at each of December 31, 2018, 2017 and 2016.

	December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
North Dakota	4,693	314.1	3,172	218.7	2,820	202.2
Montana	99	11.0	90	10.3	94	10.9
Total	4,792	325.1	3,262	229.0	2,914	213.1

As of December 31, 2018, we had an additional 412 gross (22.8 net) wells in process, meaning wells that have been spud and are in the process of drilling, completing or waiting on completion.

Leasehold Properties

As of December 31, 2018, our principal assets included approximately 157,083 net acres located in the northern region of the United States. The following table summarizes our estimated gross and net developed and undeveloped acreage by state at December 31, 2018.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
North Dakota:						
McKenzie County	127,562	29,811	7,296	4,103	134,858	33,914
Mountrail County	123,438	28,407	5,066	786	128,504	29,193
Williams County	129,299	25,201	4,613	1,582	133,912	26,783
Dunn County	75,741	16,658	6,158	684	81,899	17,342
Divide County	59,019	16,285	2,706	939	61,725	17,224
Other	99,720	16,207	3,963	1,070	103,683	17,277
North Dakota	614,779	132,569	29,802	9,164	644,581	141,733
Montana	42,637	11,639	5,086	3,711	47,723	15,350
Total:	657,416	144,208	34,888	12,875	692,304	157,083

As of December 31, 2018, approximately 92% of our total acreage was developed. All of our proved reserves are located in North Dakota and Montana.

Recent Acquisitions

See “Item 1. Business - Overview” regarding our W Energy, Pivotal, and Salt Creek Acquisitions completed in 2018. In addition to those acquisitions, during 2018 and 2017, we acquired leasehold interests covering an aggregate of approximately 10,932 and 1,934 net acres, respectively, in our key prospect areas.

We generally assess acreage subject to near-term drilling activities on a lease-by-lease basis because we believe each lease’s contribution to a subject spacing unit is best assessed on that basis if development timing is sufficiently clear. Consistent with that approach, the majority of our acreage acquisitions involve properties that are selected by us on a lease-by-lease basis for their participation in a well expected to be spud in the near future, and the subject leases are then aggregated to complete one single closing with the transferor. As such, we generally view each acreage assignment from brokers, landmen and other parties as involving several separate acquisitions combined into one closing with the common transferor for convenience. However, in certain instances an acquisition may involve a larger number of leases presented by the transferors as a single package without negotiation on a lease-by-lease basis. In those instances, we still review each lease on a lease-by-lease basis to ensure that the package as a whole meets our acquisition criteria and drilling expectations.

Acreage Expirations

As a non-operator, we are subject to lease expirations if an operator does not commence the development of operations within the agreed terms of our leases. All of our leases for undeveloped acreage summarized in the table below will expire at the end of their respective primary terms, unless we renew the existing leases, establish commercial production from the acreage or some other "savings clause" is exercised. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have been commenced. While we generally expect to establish production from most of our acreage prior to expiration of the applicable lease terms, there can be no guarantee we can do so. The approximate expiration of our net acres which are subject to expire between 2019 and 2023 and thereafter, are set forth below:

	Acreage Subject to Expiration	
Year Ended	**Gross**	**Net**
December 31, 2019	21,154	5,160
December 31, 2020	1,904	907
December 31, 2021	4,797	1,428
December 31, 2022	3,217	2,056
December 31, 2023 and thereafter	3,966	3,324
Total	35,038	12,875

During 2018, we had leases expire in Montana (620 net acres) and North Dakota (8,862 net acres) covering approximately 9,482 net acres, all of which was prospective for the Bakken and Three Forks Formations. The 2018 lease expirations carried a cost of $9.4 million. We believe that the expired acreage was not material to our capital deployed in these prospects.

Unproved Properties

All properties that are not classified as proved properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion. Once a property is classified as proved, all associated acreage and drilling costs are subject to depletion.

We assess all items classified as unproved property on an annual basis, or if certain circumstances exist, more frequently, for possible impairment or reduction in value. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and amortization. For the years ended December 31, 2018, 2017 and 2016, we included $0.3 million, $0.6 million and $7.0 million, respectively, related to expiring leases within costs subject to the depletion calculation. These amounts represent lease expiration costs that were not previously included within costs subject to the depletion calculation during a prior year.

We historically have acquired our properties by purchasing individual or small groups of leases directly from mineral owners or from landmen or lease brokers, which leases generally have not been subject to specified drilling projects, and by purchasing lease packages in identified project areas controlled by specific operators. We generally participate in drilling activities on a proportionate basis by electing whether to participate in each well on a well-by-well basis at the time wells are proposed for drilling.

We believe that the majority of our unproved costs will become subject to depletion within the next five years by proving up reserves relating to its acreage through exploration and development activities, by impairing the acreage that will expire before we can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of our reserves.

Impairment and Depletion of Oil and Natural Gas Properties

As a result of low commodity prices and their effect on the proved reserve values of properties 2016, we recorded a non-cash ceiling test impairment of $237.0 million in 2016. Given improving commodity prices, no impairments were recorded during 2018 or 2017. The impairment charges affected our reported net income but did not reduce our cash flow.

Depending on future commodity price levels, the trailing 12-month average price used in the ceiling calculation could decline and may cause additional future write downs of our oil and natural gas properties. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analyses in future periods.

Our depletion expense is driven by many factors including certain exploration costs involved in the development of producing reserves, production levels and estimates of proved reserve quantities and future developmental costs. The following table presents our depletion expenses during 2018, 2017 and 2016.

	Years Ended December 31,		
	2018	**2017**	**2016**
Depletion of Oil and Natural Gas Properties	$ 118,973,587	$ 58,801,474	$ 60,637,746
Depletion Expense (per Boe)	12.75	10.89	12.13

Research and Development

We do not anticipate performing any significant research and development under our plan of operation.

Delivery Commitments

We do not currently have any delivery commitments for product obtained from our wells.

Item 3. ***Legal Proceedings***

Our company is subject from time to time to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business.

On December 10, 2018, the U.S. District Court for the Southern District of New York dismissed, with prejudice, a class action that was originally brought on August 18, 2016 by plaintiff Jeffrey Fries, individually and on behalf of all others similarly situated, against our company, Michael Reger (our former chief executive officer), and Thomas Stoelk (our former chief financial officer and interim chief executive officer) as defendants. The original complaint was amended by plaintiff in July 2017. The court granted our motion to dismiss the amended complaint in January 2018, but permitted plaintiff the opportunity to further amend the complaint. A second amended complaint was filed by plaintiffs in January 2018. The court granted our motion to dismiss the second amended complaint, with prejudice, in December 2018. The complaints purported to bring a federal securities class action on behalf of a class of persons who acquired our company's securities between March 1, 2013 and August 15, 2016, and sought to recover damages caused by defendants' alleged violations of the federal securities laws and to pursue remedies under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder. Plaintiff did not appeal the court's dismissal of the second amended complaint, and this matter is now fully dismissed.

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

None.

PART II
Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Market Information

Our common stock trades on the NYSE American under the symbol "NOG." The closing price for our common stock on the NYSE American on March 14, 2019 was $2.53 per share.

Comparison Chart

The following information in this Item 5 of this Annual Report on Form 10-K is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

The following graph compares the 60-month cumulative total shareholder return on our common stock since December 31, 2013, and the cumulative total returns of Standard & Poor's Composite 500 Index and the NYSE Arca Oil Index (formerly the AMEX Oil Index) for the same period. This graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends) from December 31, 2013 to December 31, 2018.

*$100 invested on 12/31/13 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

* The following table sets forth the total returns utilized to generate the foregoing graph.

	12/31/2013	**12/31/2014**	**12/31/2015**	**12/31/2016**	**12/31/2017**	**12/31/2018**
Northern Oil & Gas, Inc.	100.00	37.49	25.61	18.25	13.60	15.00
S&P 500	100.00	113.69	115.26	129.05	157.22	150.33
NYSE Arca Oil Index	100.00	89.57	74.49	93.18	102.43	94.62

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Holders

As of March 14, 2019, we had 376,983,438 shares of our common stock outstanding, held by approximately 290 shareholders of record. The number of record holders does not necessarily bear any relationship to the number of beneficial owners of our common stock.

Recent Sales of Unregistered Securities

None, except to the extent previously included by the Company in a Quarterly Report on Form 10-Q or Current Report on Form 8-K.

Issuer Purchases of Equity Securities

The table below sets forth the information with respect to purchases made by or on behalf of the Company, or any “affiliated purchaser” (as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934), of our common stock during the quarter ended December 31, 2018.

Period	**Total Number of Shares Purchased(1)**	**Average Price Paid Per Share**		**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs(2)**
Month #1					
October 1, 2018 to October 31, 2018	6,120	$	4.29	—	$ 108.3 million
Month #2					
November 1, 2018 to November	7,393,553	3.25		7,359,953	84.4 million

30, 2018					
Month #3					
December 1, 2018 to December 31, 2018	54,204	2.56		—	84.4 million
Total	7,453,877	$	3.25	7,359,953	$ 84.4 million

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(1) The 93,924 total shares purchased outside of publicly announced plans or programs represent shares surrendered in satisfaction of tax withholding obligations in connection with the vesting of restricted stock awards.
(2) In May 2011, our board of directors approved a stock repurchase program to acquire up to $150 million worth of shares of our Company's outstanding common stock.

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Item 6. ***Selected Financial Data***

	Fiscal Years				
	2018	**2017**	**2016**	**2015**	**2014**
	(in thousands, except share and per common share data)				
Statements of Operations Information:					
Revenues					
Oil and Gas Sales	$ 493,909	$ 223,963	$ 159,691	$ 202,639	$ 431,605
Gain (Loss) on Derivative Instruments, Net	185,006	(14,667)	(14,819)	72,383	163,413
Other Revenue	9	23	31	36	9
Total Revenues	678,924	209,320	144,903	275,057	595,027
Operating Expenses					
Production Expenses	66,646	49,733	45,680	52,108	55,696
Production Taxes	45,302	20,604	15,514	21,567	43,674
General and Administrative Expense	14,568	18,988	14,758	19,042	17,602
Depletion, Depreciation, Amortization and Accretion	119,780	59,500	61,244	137,770	172,884
Impairment of Oil and Natural Gas Properties	—	—	237,013	1,163,959	—
Total Expenses	246,296	148,825	374,208	1,394,446	289,856
Income (Loss) from	432,628	60,495	(229,305)	(1,119,389)	305,171

Operations									
Interest Expense, Net of Capitalization	(86,005)	(70,286)		(64,486)		(58,360)		(42,106)	
Write-off of Debt Issuance Costs	—	(95)		(1,090)		—		—	
Loss on the Extinguishment of Debt	(173,430)	(993)		—		—		—	
Debt Exchange Derivative Loss	(598)	—		—		—		—	
Contingent Consideration Loss	(28,968)	—		—		—		—	
Financing Expense	(884)	—		—		—		—	
Other Income (Expense)	891	116		(16)		(30)		47	
Total Other Income (Expense)	(288,994)	(71,258)		(65,591)		(58,390)		(42,059)	
Income (Loss) Before Income Taxes	143,634	(10,764)		(294,896)		(1,177,779)		263,112	
Income Tax Provision (Benefit)	(55)	(1,570)		(1,402)		(202,424)		99,367	
Net Income (Loss)	$ 143,689	$	(9,194)	$	(293,494)	$	(975,355)	$	163,745
Net Income	$ 0.61	$	(0.15)	$	(4.80)	$	(16.08)	$	2.70

(Loss) Per Common Share – Basic									
Net Income (Loss) Per Common Share – Diluted	$ 0.61	$	(0.15)	$	(4.80)	$	(16.08)	$	2.69
Weighted Average Shares Outstanding – Basic	236,206,457	62,408,855		61,173,547		60,652,447		60,691,701	
Weighted Average Shares Outstanding – Diluted	236,773,911	62,408,855		61,173,547		60,652,447		60,860,769	
Statements of Cash Flows Information:									
Net Cash Provided By Operating Activities	$ 244,262	$	72,967	$	101,892	$	247,016	$	274,258
Net Cash Used For Investing Activities	$ (474,519)	$	(119,240)	$	(90,964)	$	(288,936)	$	(477,040)
Net Cash (Used For) Provided By Financing Activities	$ 130,431	$	141,970	$	(7,832)	$	35,973	$	206,433

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	Fiscal Years				
	2018	2017	2016	2015	2014
	(in thousands)				
Balance Sheet Information:					
Assets:					
Cash and Cash Equivalents	$ 2,358	$ 102,183	$ 6,486	$ 3,390	$ 9,338
Total Current Assets	228,415	152,758	46,894	122,030	226,000
Total Property and Equipment, Net	1,202,745	473,220	376,208	589,320	1,761,927
Total Assets	1,503,645	632,254	431,533	721,431	2,026,746
Liabilities:					
Total Current Liabilities	231,526	123,575	77,444	78,115	285,734
Long-term Debt, Net	830,203	979,324	832,625	835,290	806,053
Total Liabilities	1,073,780	1,123,094	918,955	919,033	1,255,885
Total Stockholders' Equity (Deficit)	429,865	(490,841)	(487,422)	(197,602)	770,861

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

The following discussion should be read in conjunction with the "Selected Financial Data" in Item 6 and the Financial Statements and accompanying Notes to Financial Statements appearing elsewhere in this report.

Executive Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas properties, primarily in the Bakken and Three Forks formations within the Williston Basin in North Dakota and Montana. We believe the location, size and concentration of our acreage position in one of North America's leading unconventional oil-resource plays provide us with drilling and development opportunities that will result in significant long-term value. Our primary focus is oil exploration and production through non-operated working interests in wells drilled and completed in spacing units that include our acreage. Using this strategy, we had participated in 4,792 gross (325.1 net) producing wells as of December 31, 2018.

Our financial and operating performance for the year ended December 31, 2018 included the following:

•Oil and gas sales of $493.9 million in 2018, compared to $224.0 million in 2017

•Average daily production of 25,555 Boepd in 2018, a 73% increase compared to 14,800 Boepd in 2017

•Added 97.0 net wells to production in 2018, including 65.8 net wells from acquisitions, compared to 16.9 net wells added to production in 2017

•Proved reserves of 135.5 MMBoe at December 31, 2018, a 79% increase compared to December 31, 2017, as estimated by our third-party reserve engineers under SEC guidelines

•Significantly accelerated our growth with several large acquisitions, specifically the W Energy Acquisition, Pivotal Acquisition and Salt Creek Acquisition that together contributed approximately 32%, or 11,503 Boe per day, of our average daily production in the fourth quarter of 2018. See "2018 Acquisitions" below.

2018 Acquisitions

During 2018, we significantly accelerated our growth through several larger acquisitions of non-operated asset packages:

•***W Energy Acquisition***. On October 1, 2018, we closed on an acquisition of approximately 27.2 net producing wells, 5.9 net wells in process and 10,633 net acres in North Dakota from WR Operating LLC. We paid a combination of cash, equity and contingent consideration to acquire the assets, which we estimated to have a combined fair value of $341.6 million at closing.

•***Pivotal Acquisition***. On September 17, 2018, we closed on acquisitions of approximately 20.8 net producing wells, 2.2 net wells in process and 444 net acres in North Dakota from Pivotal Williston Basin, LP and Pivotal Williston Basin II, LP. We paid a combination of cash, equity and contingent consideration to acquire the assets, which we estimated to have a combined fair value of $146.1 million at closing.

•***Salt Creek Acquisition***. On June 4, 2018, we closed on an acquisition of approximately 5.5 net producing wells, 1.5 net wells in process and 1,319 net acres in North Dakota from Salt Creek Oil and Gas, LLC. We paid a combination of cash and equity consideration to acquire the assets, which we estimated to have a combined fair value of $60.0 million at closing.

Source of Our Revenues

We derive our revenues from the sale of oil, natural gas and NGLs produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, oil quality, Btu content and transportation costs to market. We use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our oil production. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements.

Principal Components of Our Cost Structure

•*Oil price differentials*. The price differential between our Williston Basin well head price and the NYMEX WTI benchmark price is driven by the additional cost to transport oil from the Williston Basin via train, pipeline or truck to refineries.

•*Gain (loss) on derivative instruments, net.* We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of oil. Gain (loss) on derivative instruments, net is comprised of (i) cash gains and losses we recognize on settled derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on derivative instruments outstanding at period-end.

•*Production expenses.* Production expenses are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include field personnel compensation, salt water disposal, utilities, maintenance, repairs and servicing expenses related to our oil and natural gas properties.

•*Production taxes.* Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We seek to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

•*Depreciation, depletion, amortization and impairment.* Depreciation, depletion, amortization and impairment includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas properties. As a full cost company, we capitalize all costs associated with our development and acquisition efforts and allocate these costs to each unit of production using the units-of-production method.

•*General and administrative expenses.* General and administrative expenses include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our acquisition and development operations, franchise taxes, audit and other professional fees and legal compliance.

•*Interest expense.* We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We capitalize a portion of the interest paid on applicable borrowings into our full cost pool. We include interest expense that is not capitalized into the full cost pool, the amortization of deferred financing costs and bond premiums (including origination and amendment fees), commitment fees and annual agency fees as interest expense.

•*Income tax expense.* Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. 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 and carryforwards 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. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Selected Factors That Affect Our Operating Results

Our revenues, cash flows from operations and future growth depend substantially upon:

•the timing and success of drilling and production activities by our operating partners;

•the prices and the supply and demand for oil, natural gas and NGLs;

•the quantity of oil and natural gas production from the wells in which we participate;

•changes in the fair value of the derivative instruments we use to reduce our exposure to fluctuations in the price of oil;

•our ability to continue to identify and acquire high-quality acreage and drilling opportunities; and

•the level of our operating expenses.

In addition to the factors that affect companies in our industry generally, the location of our acreage and wells in the Williston Basin subjects our operating results to factors specific to this region. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter and spring months, and the limitations of the developing infrastructure and transportation capacity in this region.

The price of oil in the Williston Basin can vary depending on the market in which it is sold and the means of transportation used to transport the oil to market. Light sweet crude from the Williston Basin has a higher value at many major refining centers because of its higher quality relative to heavier and sour grades of oil; however, because of North Dakota’s location relative to traditional oil transport centers, this higher value is generally offset to some extent by higher transportation costs. While rail transportation has historically been more expensive than pipeline transportation, Williston Basin prices have at times justified shipment by rail to markets on the gulf coast and east coast, which offer prices benchmarked to LLS/Brent. Additional pipeline infrastructure has increased takeaway capacity in the Williston Basin which has improved wellhead values in the region.

The price at which our oil production is sold typically reflects a discount to the NYMEX benchmark price. Thus, our operating results are also affected by changes in the oil price differentials between the NYMEX and the sales prices we receive for our oil production. Our oil price differential to the NYMEX benchmark price during 2018 was $7.12 per barrel, as compared to $5.87 per barrel in 2017. Fluctuations in our oil price differential are due to several factors such as takeaway capacity relative to production levels in the Williston Basin, and seasonal refinery maintenance temporarily depressing crude demand.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells has varied significantly over the past few years as volatility in oil prices has substantially impacted the level of drilling activity in the Williston Basin. Generally, higher oil prices have led to increased drilling activity, with the increased demand for drilling and completion services driving these costs higher. Lower oil prices have generally had the opposite effect. In addition, individual components of the cost can vary depending on numerous factors such as the length of the horizontal lateral, the number of fracture stimulation stages, and the choice of proppant (sand or ceramic).

Higher commodity prices in late 2017 and 2018 increased our drilling activity in the Williston Basin during the year ended December 31, 2018. Rig activity levels in 2018 increased from 2017 levels and a large percentage of our newer wells utilize higher intensity completion techniques. The higher intensity completions generally deliver the best returns in the current pricing environment but cost more due to increased materials and servicing costs. During 2018, the weighted average authorization for expenditure (or AFE) cost for wells we elected to participate in was $8.1 million, compared to $7.5 million for the wells we elected to participate in during 2017.

Market Conditions

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Being primarily an oil producer, we are more significantly impacted by changes in oil prices than by changes in the price of natural gas. World-wide supply in terms of output, especially production from the United States, the production quota set by OPEC, and the strength of the U.S. dollar can adversely impact oil prices. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Factors impacting the future oil supply balance are world-wide demand for oil, as well as the growth in domestic oil production.

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the years ended December 31, 2018, 2017 and 2016.

	December 31,		
	2018	**2017**	**2016**
Average NYMEX Prices(1)			
Oil (per Bbl)	$ 64.95	$ 50.85	$ 43.47
Natural Gas (per Mcf)	3.16	3.02	2.55

(1) Based on average NYMEX closing prices.

The average 2018 NYMEX pricing was $64.95 per barrel of oil or 28% higher than the average NYMEX price per barrel in 2017, which was partially offset by a decrease in settled derivatives in 2018 as compared to 2017. Our average 2018 realized oil price per barrel after reflecting settled derivatives was $54.84 or 19% higher than 2017.

As of December 31, 2018, we had a total volume on open commodity swaps of 12.3 million barrels at a weighted average price of approximately $62.31 per barrel. The following table reflects the weighted average price of open commodity price swap derivative contracts as of December 31, 2018, by year with associated volumes.

Weighted Average Price Of Open Commodity Swap Contracts

Year	**Volumes (Bbl)**	**Weighted Average Price ($)**
2019	6,851,730	63.32
2020	4,186,080	61.01
2021 and beyond	1,310,100	61.18

In addition to the open commodity price swap contracts we have entered into basis swap contracts. Basis swaps fix the price differential between a published index price and the applicable local index price under which our production is sold. The following table reflects open commodity basis swap contracts as of December 31, 2018.

Settlement Period	**Oil (Barrels)**	**Weighted Average Price ($)**
01/01/19 – 12/31/19	3,650,000	(2.41)

Results of Operations for 2018, 2017 and 2016

The following table sets forth selected operating data for the periods indicated. Production volumes and average sales prices are derived from accrued accounting data for the relevant period indicated.

	Years Ended December 31,		
	2018	**2017**	**2016**
Net Production:			
Oil (Bbl)	7,790,182	4,537,295	4,325,919
Natural Gas and NGLs (Mcf)	9,224,766	5,187,886	4,026,899
Total (Boe)	9,327,643	5,401,943	4,997,069
Net Sales (in thousands):			
Oil Sales	$ 450,149	$ 204,581	$ 152,348
Natural Gas and NGL Sales	43,760	19,382	7,343
Gain (Loss) on Settled Derivatives	(22,886)	3,777	61,528
Gain (Loss) on Mark-to-Market of Derivative Instruments	207,892	(18,443)	(76,347)
Other Revenue	9	23	31
Total Revenues	678,924	209,320	144,903
Average Sales Prices:			
Oil (per Bbl)	$ 57.78	$ 45.09	$ 35.22
Effect of Gain (Loss) on Settled Derivatives on Average Price (per Bbl)	(2.94)	0.83	14.22
Oil Net of Settled Derivatives (per Bbl)	54.84	45.92	49.44
Natural Gas and NGLs (per Mcf)	4.74	3.74	1.82
Realized Price on a Boe Basis Including all Realized Derivative Settlements	50.50	42.16	44.27

Operating Expenses (in thousands):						
Production Expenses	$	66,646	$	49,733	$	45,680
Production Taxes	45,302		20,604		15,514	
General and Administrative Expenses	14,568		18,988		14,758	
Depletion, Depreciation, Amortization and Accretion	119,780		59,500		61,244	
Costs and Expenses (per Boe):						
Production Expenses	$	7.15	$	9.21	$	9.14
Production Taxes	4.86		3.81		3.10	
General and Administrative Expenses	1.56		3.51		2.95	
Depletion, Depreciation, Amortization and Accretion	12.84		11.01		12.26	
Net Producing Wells at Period-End	325.1		229.0		213.1	

Oil and Natural Gas Sales

Our revenues vary from year to year primarily as a result of changes in realized commodity prices and production volumes. In 2018, our oil, natural gas and NGL sales, excluding the effect of settled derivatives, increased 121% from 2017, driven by a 73% increase in production volumes and a 28% increase in realized price, excluding the effect of settled derivatives. The higher average realized price in 2018 as compared to 2017 was principally driven by higher average NYMEX oil and natural gas prices. These higher prices were partially offset by a higher average oil price differential in 2018 as compared to 2017, which was the most pronounced in the fourth quarter of 2018, coinciding with our highest levels of production for the year. The oil price differential during 2018 averaged $7.12 per barrel, as compared to $5.87 per barrel in 2017.

In 2017, oil, natural gas and NGL sales, excluding the effect of settled derivatives, increased 40% from 2016, driven primarily by an 8% increase in production levels and a 28% increase in our average oil sales price. The higher average realized price per Boe, excluding the effect of settled derivatives, in 2017 as compared to 2016 was primarily driven by higher average NYMEX oil and gas prices, as well as a lower oil price differential. Oil price differential during 2017 averaged $5.87 per barrel, as compared to $8.25 per barrel in 2016.

We add production through drilling success as we place new wells into production and through additions from acquisitions, which is offset by the natural decline of our oil and natural gas production from existing wells. During 2018, our substantial acquisition activities (see Note 3 to our financial statements) combined with increased development activity and improved performance from enhanced completion techniques drove the 73% increase in production as compared to 2017. During 2018, we added 97.0 total net wells to production, including 65.8 net wells from acquisitions. Excluding the wells added from acquisitions, this was an 85% increase as compared to 2017. Our acquisition program is a significant driver of our net well additions. In 2017, the number of net wells we added to production increased by 58% as compared to 2016. The higher number of new well completions and per well productivity improvements drove the 8% increase in production as compared to 2016. Our production for each of the last three years is set forth in the following table:

	Year Ended December 31,		
	2018	**2017**	**2016**
Production:			
Oil (Bbl)	7,790,184	4,537,295	4,325,919
Natural Gas and NGL (Mcf)	9,224,766	5,187,886	4,026,899
Total (Boe)(1)	9,327,643	5,401,943	4,997,069
Average Daily Production:			
Oil (Bbl)	21,343	12,431	11,819
Natural Gas and NGL (Mcf)	25,273	14,213	11,002
Total (Boe)(1)	25,555	14,800	13,653

(1) Natural gas and NGLs are converted to Boe at the rate of one barrel equals six Mcf based upon the approximate relative energy content of oil and natural gas, which is not necessarily indicative of the relationship of oil and natural gas prices.

Derivative Instruments

We enter into derivative instruments to manage the price risk attributable to future oil production. Our gain (loss) on derivative instruments, net was a gain of $185.0 million in 2018, compared to a loss of $14.7 million in 2017, and a loss of $14.8 million in 2016. Gain (loss) on derivative instruments, net is comprised of (i) cash gains and losses we recognize on settled derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on derivative instruments outstanding at period-end.

For 2018, we realized a loss on settled derivatives of $22.9 million, compared to a $3.8 million gain in 2017 and a $61.5 million gain in 2016. The percentage of oil production hedged under our derivative contracts was 64%, 62%, and 42% in 2018, 2017, and 2016, respectively. The weighted average oil price on our settled derivative contracts in 2018, 2017, and 2016 was $59.27, $52.61, and $77.50, respectively. Our average realized price (including all cash derivative settlements) in 2018 was $50.50 per Boe compared to $42.16 per Boe in 2017, and $44.27 per Boe in 2016. The gain (loss) on settled derivatives decreased our average realized price per Boe by $2.45 in 2018, increased our average realized price per Boe by $0.70 in 2017 and increased our average realized price per Boe by $12.31 in 2016.

Mark-to-market derivative gains and losses was a gain of $207.9 million in 2018 compared to a loss of $18.4 million in 2017 and a loss of $76.3 million in 2016. Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as gains and losses from unsettled derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Any gains on our derivatives will be offset by lower wellhead revenues in the future or any losses will be offset by higher future wellhead revenues based on the value at the settlement date. At December 31, 2018, all of our derivative contracts are recorded at their fair value, which was a net asset of $177.7 million, an increase of $207.9 million from the $30.2 million net liability recorded as of December 31, 2017. The increase in the net asset at December 31, 2018 as compared to December 31, 2017 was primarily due to changes in oil prices on the open oil derivative contracts. Our open oil derivative contracts are summarized in “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

Production Expenses

Production expenses were $66.6 million in 2018 compared to $49.7 million in 2017 and $45.7 million in 2016. On a per unit basis, production expenses decreased 22% from $9.21 per Boe in 2017 to $7.15 per Boe in 2018 due primarily to higher production levels over which fixed costs are spread. On an absolute dollar basis, our production expenses in 2018 were 34% higher when compared to 2017 due primarily to a 73% increase in production and a 42% increase in net producing wells, offset by the decline in per unit costs. On a per unit basis, our production expenses were relatively flat from $9.14 per Boe in 2016 to $9.21 per Boe in 2017. On an absolute dollar basis, our production expenses in 2017 were 9% higher when compared to 2016 due primarily to an 8% increase in production.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Higher production levels and commodity prices in 2018 as compared to 2017, and in 2017 as compared to 2016, increased the taxable base that is used to calculate production taxes. Production taxes were $45.3 million in 2018 compared to $20.6 million in 2017 and $15.5 million in 2016. As a percentage of oil and natural gas sales, our average production tax rates were 9.2%, 9.2% and 9.7% in 2018, 2017 and 2016, respectively. The lower average production tax rates in 2018 and 2017, compared to 2016, is due to an increase in our natural gas sales as a percentage of our total oil and gas sales. Gas sales are taxed at a lower rate than oil sales.

General and Administrative Expenses

General and administrative expenses were $14.6 million for 2018 compared to $19.0 million for 2017 and $14.8 million for 2016. The decrease in 2018 compared to 2017 was due in part to a $3.6 million litigation settlement charge in the third quarter of 2017 and a $1.2 million reversal of non-cash share-based compensation expense in connection with the resignation of a former executive officer in the first quarter of 2018.

General and administrative expenses in 2017 as compared to 2016 were higher due in part to a $3.6 million litigation settlement charge in the third quarter of 2017. In addition, legal and professional expense was $1.3 million higher in 2017 as compared to 2016, partially offset by a $0.2 million decrease in cash compensation expense due primarily to reduced incentive compensation.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion (“DD&A”) was $119.8 million in 2018 compared to $59.5 million in 2017 and $61.2 million in 2016. Depletion expense, the largest component of DD&A, was $12.75 per Boe in 2018 compared to $10.89 per Boe in 2017 and $12.13 per Boe in 2016. The aggregate increase in depletion expense for 2018 compared to 2017 was driven by a 73% increase in production levels and a 17% increase in the depletion rate per Boe. The 2018 depletion rate per Boe was higher due to an increase in well costs and the impact of recent acquisition in 2018. The aggregate increase in depletion expense for 2017 compared to 2016 was driven by an 8% increase in production levels which was partially offset by a 10% decrease in the depletion rate per Boe. The 2017 depletion rate per Boe was lower due to the previous impairment of oil and gas properties, which lowered the depletable base. The following table summarizes DD&A expense per Boe for 2018, 2017 and 2016:

	Year Ended December 31,						Year Ended December 31,	
	2018	**2017**	**Change**	**Change**	**2017**	**2016**	**Change**	**Change**
Depletion	$ 12.75	$ 10.89	$ 1.86	17%	$ 10.89	$ 12.13	$ (1.24)	(10)%
Depreciation, Amortization, and Accretion	0.12	0.12	—	—%	0.12	0.13	(0.01)	(8)%
Total DD&A expense	$ 12.87	$ 11.01	$ 1.86	17%	$ 11.01	$ 12.26	$ (1.25)	(10)%

Impairment of Oil and Natural Gas Properties

We did not have any impairment of our proved oil and gas properties in 2018 and 2017. As a result of low prevailing commodity prices during 2016, and their effect on the proved reserve values of our properties, we recorded a non-cash ceiling test impairment of $237.0 million in 2016. The impairment charge affected our reported net income but did not reduce our cash flow.

Depending on future commodity price levels, the trailing twelve-month average price used in the ceiling calculation may decline, which could cause additional future write downs of our oil and natural gas properties. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analysis in future periods.

Interest Expense

Interest expense, net of capitalized interest, was $86.0 million in 2018 compared to $70.3 million in 2017 and $64.5 million in 2016. The increase in interest expense for 2018 as compared to 2017 was primarily due to an increase in average borrowings outstanding between periods with higher interest rates and a lower amount of capitalized interest cost. A portion of the increased interest expense was non-cash payment-in-kind interest under our Second Lien Notes. The higher interest rates were associated in large part with our Term Loan Credit Facility, which was retired in October 2018 and replaced with a lower cost and more flexible Revolving Credit Facility. See "Liquidity and Capital Resources" below. The increase in interest expense for 2017 as compared to 2016 was primarily due to an increase in average borrowings outstanding between periods, a lower amount of capitalized interest cost and a higher interest rate on the term loan credit agreement that was completed in November 2017 as compared to borrowings under our prior revolving credit facility (which was repaid with proceeds from the term loan credit agreement).

Loss on the Extinguishment of Debt

As a result of the exchange agreements and early redemptions of our 8% senior unsecured notes and our term loan credit agreement during 2018 (see Note 4 to our financial statements), we recorded a loss on the extinguishment of debt of $173.4 million for the year ended December 31, 2018 based on the differences between the reacquisition costs of retiring the applicable debt and the net carrying values thereof. During 2017, we recorded a loss on extinguishment of debt of $1.0 million as a result of the early termination of a prior revolving credit facility. There was no loss on the extinguishment of debt during the year ended 2016.

Debt Exchange Derivative Loss

In connection with certain exchange transactions with respect to our Unsecured Notes (see Note 4 to our financial statements), we incurred debt exchange derivative liabilities during 2018. During the year ended December 31, 2018, we recorded a debt exchange derivative liability loss of $0.6 million due to the change in the fair value of our debt exchange derivative liabilities (see Note 12 to our financial statements). There was no debt exchange derivative liability gain or loss during 2017 or 2016.

Contingent Consideration Loss

In connection with the W Energy Acquisition and the Pivotal Acquisition, (see Note 3 to our financial statements), we incurred contingent consideration liabilities during 2018. During the year ended December 31, 2018, we recorded a contingent consideration loss of $29.0 million due to the change in the fair value of our contingent consideration liabilities (see Note 12 to our financial statements). There was no contingent consideration gain or loss during 2017 or 2016.

Income Tax Benefit

We recognized income tax benefit of $0.1 million, $1.6 million, and $1.4 million in 2018, 2017, and 2016, respectively. The effective tax rate was zero, 14.6%, and 0.5% in 2018, 2017, and 2016, respectively. In 2018, 2017, and 2016, the tax benefits recognized related to the utilization of our alternative minimum tax credit as a result of favorable tax incentives. We have recorded a valuation allowance against effectively all of our net deferred tax assets due to uncertainty regarding their realization in 2018 and 2017.

We intend to continue maintaining a full valuation allowance on our deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of these allowances. However, given our current earnings and potential future earnings, we believe that there is a reasonable possibility that within the next 12 months, sufficient positive evidence may become available to allow us to reach a conclusion that a significant portion of the valuation allowance will no longer be needed. Release of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense for the period the release is recorded. However, the exact timing and amount of the valuation allowance release are subject to change on the basis of the level of profitability that we are able to actually achieve. For further discussion of our valuation allowance, see Note 10 to our financial statements.

Non-GAAP Financial Measures

Adjusted Net Income and Adjusted EBITDA are non-GAAP measures. Net income (loss) is the most directly comparable GAAP measure for both Adjusted Net Income and Adjusted EBITDA, and tabular reconciliations for these measures are included below. We recorded net income of $143.7 million (representing $0.61 per diluted share) for 2018, compared to a net loss of $9.2 million (representing $(0.15) per diluted share) for 2017 and a net loss of $293.5 million (representing $(4.80) per diluted share) for 2016.

We define Adjusted Net Income (Loss) as net income (loss) excluding (i) (gain) loss on the mark-to-market of derivative instruments, net of tax, (ii) financing expense, net of tax, (iii) impairment of oil and natural gas properties, net of tax, (iv) write-off of debt issuance costs, net of tax, (v) loss on the extinguishment of debt, net of tax, (vi) debt exchange derivative loss, net of tax, (vii) certain legal settlements, net of tax, and (viii) contingent consideration loss, net of tax. Our Adjusted Net Income for 2018 was $140.7 million (representing $0.59 per diluted share) as compared to Adjusted Net Income for 2017 of $8.5 million (representing $0.14 per diluted share) and Adjusted Net Income of $12.2 million (representing $0.20 per diluted share) for 2016. The increase in Adjusted Net Income in 2018 compared to 2017 was primarily due to significantly higher production volumes as a result of our acquisitions and organic growth, decreased per unit expenses and higher realized commodity prices (after the effect of settled derivatives), which were partially offset by higher interest costs. The decrease in Adjusted Net Income in 2017 compared to 2016 was primarily due to lower realized commodity prices (after the effect of settle derivatives), and higher general and administrative expenses, production expenses, and interest costs, which were partially offset by lower depletion expense and higher production volumes.

We define Adjusted EBITDA as net income (loss) before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization, and accretion, (iv) (gain) loss on the mark-to-market of derivative instruments, (v) non-cash share based compensation expense, (vi) write-off of debt issuance costs, (vii) loss on the extinguishment of debt, (viii) impairment of oil and natural gas properties, (ix) debt exchange derivative loss, (x) contingent consideration loss, and (xi) financing expense. Adjusted EBITDA for 2018 was $349.3 million, compared to Adjusted EBITDA of $144.7 million in 2017 and $148.5 million in 2016. The increase in Adjusted EBITDA in 2018 as compared to 2017 is primarily due to significantly higher production volumes as a result of our acquisitions and organic growth, decreased per unit expenses and higher realized commodity prices (after the effect of settled derivatives). The decrease in Adjusted EBITDA in 2017 as compared to 2016 was primarily due to lower realized commodity prices (after the effect of settled derivatives) and higher general and administrative expenses, which were partially offset by higher production volumes.

Management believes the use of these non-GAAP financial measures provides useful information to investors to gain an overall understanding of our current financial performance. Specifically, management believes the non-GAAP financial measures included herein provide useful information to both management and investors by excluding certain items that our management believes are not indicative of our core operating results. In addition, these non-GAAP financial measures are used by management for budgeting and forecasting as well as subsequently measuring our performance, and we believe that we are providing investors with financial measures that most closely align to our internal measurement processes. We consider these non-GAAP measures to be useful in evaluating our core operating results as they provide useful information regarding our essential revenue generating activities and direct operating expenses (resulting in cash expenditures) needed to perform these revenue generating activities. Our management also believes, based on feedback provided by the investment community, that the non-GAAP financial measures are necessary to allow the investment community to construct its valuation models to better compare our results with our competitors and market sector.

These measures should be considered in addition to results prepared in accordance with GAAP. In addition, these non-GAAP financial measures are not based on any comprehensive set of accounting rules or principles. We believe that non-GAAP financial measures have limitations in that they do not reflect all of the amounts associated with our results of operations as determined in accordance with GAAP and that these measures should only be used to evaluate our results of operations in conjunction with the corresponding GAAP financial measures.

Reconciliation of Adjusted Net Income

	Years Ended December 31,		
	2018	2017	2016
	(in thousands, except share and per common share data)		
Net Income (Loss)	$ 143,689	$ (9,194)	$ (293,494)
Add:			
Impact of Selected Items:			
(Gain) Loss on the Mark-to-Market of Derivative Instruments	(207,892)	18,443	76,347
Financing Expense	884	—	—
Impairment of Oil and Natural Gas Properties	—	—	237,013
Write-off of Debt Issuance Costs	—	95	1,090
Loss on the Extinguishment of Debt	173,430	993	—
Debt Exchange Derivative Loss	598	—	—
Contingent Consideration Loss	28,968	—	—
Legal Settlements	—	3,589	—
Selected Items, Before Income Taxes	(4,012)	23,121	314,449
Income Tax of Selected Items(1)	983	(5,388)	(8,723)
Selected Items, Net of Income Taxes	(3,029)	17,733	305,726
Adjusted Net Income	$ 140,660	$ 8,539	$ 12,233
Weighted Average Shares Outstanding – Basic	236,206,457	62,408,855	61,173,547

Weighted Average Shares Outstanding – Diluted	236,773,911	62,769,234		61,824,749
Net Income (Loss) Per Common Share – Basic	$ 0.61	$	(0.15)	$ (4.80)
Add:				
Impact of Selected Items, Net of Income Taxes	(0.01)	0.29		5.00
Adjusted Net Income Per Common Share – Basic	$ 0.60	$	0.14	$ 0.20
Net Income (Loss) Per Common Share – Diluted	$ 0.61	$	(0.15)	$ (4.75)
Add:				
Impact of Selected Items, Net of Income Taxes	(0.02)	0.29		4.95
Adjusted Net Income Per Common Share – Diluted	$ 0.59	$	0.14	$ 0.20

(1) The 2018 column represents a tax impact using an estimated tax rate of 24.5% and does not include any adjustments for changes in our valuation allowance. The 2017 column represents a tax impact using an estimated tax rate of 39.1% and includes adjustments for changes in our valuation allowance of $3.7 million, excluding the impact for the Tax Cuts and Jobs Act that was enacted on December 22, 2017. The 2016 column represents a tax impact using an estimated tax rate of 37.4% and includes adjustments for changes in our valuation allowance of $109.0 million.

Reconciliation of Adjusted EBITDA

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Net Income (Loss)	$ 143,689	$ (9,194)	$ (293,494)
Add:			
Interest Expense	86,005	70,286	64,486
Income Tax Provision (Benefit)	(55)	(1,570)	(1,402)
Depreciation, Depletion, Amortization and Accretion	119,780	59,500	61,244
Impairment of Oil and Natural Gas Properties	—	—	237,013
Non-Cash Share Based Compensation	3,876	6,107	3,182
Write-off of Debt Issuance Costs	—	95	1,090
Loss on the Extinguishment of Debt	173,430	993	—
Debt Exchange Derivative Loss	598	—	—
Contingent Consideration Loss	28,968	—	—
Financing Expense	884	—	—
(Gain) Loss on the Mark-to-Market of Derivative Instruments	(207,892)	18,443	76,347
Adjusted EBITDA	$ 349,283	$ 144,661	$ 148,465

Liquidity and Capital Resources

Overview

Our main sources of liquidity and capital resources as of the date of this report have been internally generated cash flow from operations, proceeds from equity and debt financings, credit facility borrowings and cash settlements of derivative contracts. Our primary uses of capital have been for the acquisition and development of our oil and natural gas properties. We continually monitor potential capital sources for opportunities to enhance liquidity or otherwise improve our financial position.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility. Oil accounted for 84% of our total production volumes in both 2018 and 2017. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas and NGL prices. We continue to maintain a robust hedging program to partially mitigate volatility in the price of crude oil with respect to a portion of our expected oil production. For the years ended 2018 and 2017, we hedged approximately 64% and 62% of our crude oil production, respectively.

As of December 31, 2018, we had derivative swap contracts hedging approximately, 6.9 million, 4.2 million and 1.3 million barrels of oil in 2019, 2020 and 2021, respectively, at an average price per barrel of $63.32, $61.01 and $61.18, respectively.

The low commodity price environment of the last several years adversely affected our business, financial position, results of operations and cash flow. During this time, we took steps to mitigate the effects of these lower prices, including: implementing cost savings initiatives, adjusting our capital expenditure budget, reviewing possible divestitures, and other actions. In November 2017, we entered into a new term loan credit agreement with TPG Specialty Lending, Inc. and the lenders party thereto (the “Term Loan Credit Facility”). We used the Term Loan Credit Facility to retire and replace our prior revolving credit facility, thereby addressing the near-term maturity of that prior facility and eliminating the potential degradation in liquidity caused by the prior facility’s borrowing base re-determination feature. The Term Loan Credit Facility provided us with additional liquidity and financial flexibility to explore investment in asset development, M&A opportunities, and meet our near- and medium-term financial obligations.

After the closing of the Term Loan Credit Facility, we continued to focus on reducing our outstanding debt and extending our maturities while maintaining liquidity. On January 31, 2018, we entered into an exchange agreement (that was subsequently amended) with certain holders (the “Supporting Noteholders”) of approximately $496.7 million, or 71%, of the aggregate principal amount of our 8.000% senior unsecured notes due 2020 (the “Unsecured Notes”), pursuant to which the Supporting Noteholders agreed to exchange all of the Unsecured Notes held by each such Supporting Noteholder for approximately $155.0 million of our common stock and approximately $344.3 million in aggregate principal amount of new senior secured second lien notes, subject to various conditions (such exchange, the “Exchange Transaction”). One of the conditions to closing the Exchange Transaction, among others, was a requirement that we raise at least $140 million in gross cash proceeds from the sale of our common stock (the “Equity Raise”). We satisfied the Equity Raise requirement with the combined proceeds from our April 2018 underwritten public offering of common stock and additional proceeds from private subscription agreements for common stock that closed simultaneously with the closing of the Exchange Transaction. The Exchange Transaction closed on May 15, 2018. See Note 4 to our financial statements for additional information regarding this Exchange Transaction.

After the closing of the Exchange Transaction (and related Equity Raise), we continued to focus on reducing our outstanding debt and addressing our nearest term maturity, which was our 8.000% senior unsecured notes due 2020 (the “Unsecured Notes”). From June-September 2018, we entered into a number of independent, separately negotiated exchange agreements with holders of our Unsecured Notes. Pursuant to each such exchange agreement, we agreed to issue the holder shares of our common stock in exchange for Unsecured Notes. In total during 2018, we issued 32.8 million shares of common stock in exchange for the retirement of $100.5 million in principal amount of the Unsecured Notes pursuant to these exchange agreements. See Note 4 to our financial statements for additional information regarding these exchange transactions.

In October 2018, we completed a series of refinancing transactions (see Note 4 to our financial statements), including (i) the issuance of an additional $350 million in Second Lien Notes, (ii) the entry into a new revolving credit facility (the “Revolving Credit Facility”) to replace our Term Loan Credit Facility, (iii) the retirement and repayment in full of our Term Loan Credit Agreement, and (iv) the redemption and repayment in full of all remaining outstanding Unsecured Notes. We continually seek to maintain a financial profile that provides operational flexibility. However, a decline in our realized commodity price could have a negative impact on our ability to maintain our desired levels of liquidity and/or raise additional capital.

As of December 31, 2018, we had cash on hand of $2.4 million, and our outstanding long-term debt consisted of (i) $140.0 million of borrowings under our Revolving Credit Facility, leaving $285.0 million of additional committed borrowing availability under the facility, and (ii) $695.1 million aggregate principal amount of senior secured second lien notes due 2023 (the “Second Lien Notes”).
With our cash on hand, cash flow from operations, and borrowing capacity under our Revolving Credit Facility, we believe that we will have sufficient cash flow and liquidity to fund our budgeted capital expenditures and operating expenses for at least the next twelve months. However, we may seek additional access to capital and liquidity. We cannot assure you, however, that any additional capital will be available to us on favorable terms or at all.

The increase in oil prices that we’ve experienced since late 2017 has increased our cash flows from operating activities, however, a return to sustained lower oil prices could significantly reduce or eliminate our planned capital expenditures. If production is not replaced through the acquisition or drilling of new wells our production levels will lower due to the natural decline of production from existing wells. Reduced production levels combined with low commodity prices would lower cash flow from operations and could adversely affect our ability to meet the covenant requirements under our debt agreements. While we were in compliance with our financial covenants under the Revolving Credit Facility at December 31, 2018, there is no assurance we will be able to maintain compliance with covenants under our debt agreements in the future.

In 2018, an increase in production and higher commodity prices have increased our our cash flow from operations, which exceeded our cash spend for drilling and development activities by $27.6 million for the year ended December 31, 2018, excluding cash paid for the acquisition of oil and natural gas properties. With higher production and the impact of recent acquisitions, we anticipate that we will continue to generate a cash flow surplus in future periods (excluding cash paid for any acquisitions).

Our recent capital commitments have been to fund drilling in the Williston Basin and to fund acquisitions of acreage and oil and gas properties. We expect to fund our near-term capital requirements and working capital needs with cash flows from operations and available borrowing capacity under our Revolving Credit Facility. Our capital expenditures could be curtailed if our cash flows decline from expected levels. Because production from existing oil and natural gas wells declines over time, reductions of capital expenditures used to drill and complete new oil and natural gas wells would likely result in lower levels of oil and natural gas production in the future.

Working Capital

Our working capital balance fluctuates as a result of changes in commodity pricing and production volumes, collection of receivables, expenditures related to our development and production operations and the impact of our outstanding derivative instruments.

At December 31, 2018, we had a working capital deficit of $3.1 million, compared to a surplus of $29.2 million at December 31, 2017. Current assets increased by $75.7 million and current liabilities increased by $108.0 million at December 31, 2018, compared to December 31, 2017. The increase in current assets in 2018 as compared to 2017 is primarily due to an increase of $115.9 million in our derivative instruments, due to the change in fair value as a result of oil price projections, and higher accounts receivable of $49.5 million due to higher commodity prices and a 73% year-over-year increase in production levels. The foregoing was partially offset by a decrease in our cash balance of $99.8 million as a result of acquisitions of oil and natural gas properties as well as replacing the term loan credit agreement with our new revolving credit facility, which does not require us to carry large amounts of cash due to its revolving nature. The change in current liabilities in 2018 as compared to 2017 is primarily due to an increase of $42.3 million in accounts payable primarily as a result of increased development activity, contingent consideration liabilities incurred of $58.1 million in connection with our Pivotal and W Energy Acquisitions (see Note 3 to our financial statements), and debt exchange derivative liabilities incurred of $18.2 million (see Note 4 to our financial statements). The foregoing was partially offset by an $18.7 million decrease in derivative instruments.

Cash Flows

Our cash flows for the years ended December 31, 2018, 2017 and 2016 are presented below:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Net Cash Provided by Operating Activities	$ 244,262	$ 72,967	$ 101,892
Net Cash Used for Investing Activities	(474,519)	(119,240)	(90,964)
Net Cash Provided by (Used for) Financing Activities	130,431	141,970	(7,832)
	$ (99,826)	$ 95,697	$ 3,096

Net Change
in Cash

Cash Flows from Operating Activities

Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivative contracts. Our cash flows from operations also are impacted by changes in working capital. Any payments due to counterparties under our derivative contracts are generally funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash on hand, cash flows from operations or borrowings under our revolving credit facility. As of December 31, 2018, we had entered into derivative swap contracts hedging approximately 6.9 million, 4.2 million and 1.3 million barrels of oil in 2019, 2020 and 2021, respectively, at an average price per barrel of $63.32 and $61.01 and $61.18, respectively. See “Item 7A. Quantitative and Qualitative Disclosures about Market Risk.”

The increase in net cash provided by operating activities in 2018 was caused by improving commodity prices and a 73% year-over-year increase in production, which was partially offset by an $26.7 million reduction in settled derivatives when compared to 2017. The decline in net cash provided by operating activities in 2017 was caused by a $57.8 million reduction in settled derivatives, which was partially offset by an 8% year-over-year increase in production and improved commodity prices when compared to 2016.

Cash Flows from Investing Activities

We had cash flows used in investing activities of $474.5 million, $119.2 million and $91.0 million during the years ended December 31, 2018, 2017 and 2016, respectively, primarily as a result of our capital expenditures for drilling, development and acquisition costs. The year-over-year increase in cash used in investing activities in 2018 was attributable to higher development spending and acquisitions, in particular our Salt Creek, Pivotal and W Energy acquisitions (see Note 3 to our financial statements). The year-over-year increase in cash used in investing activities in 2017 was attributable to higher oil and gas development activities. During 2018, 2017 and 2016 we added 31.2 (excluding already producing wells from acquisitions), 16.9 and 10.7 net wells to production, respectively.

Our cash flows used in investing activities reflects actual cash spending, which can lag several months from when the related costs were incurred. As a result, our actual cash spending is not always reflective of current levels of development activity. For instance, during the year ended December 31, 2018, our capitalized costs incurred, excluding non-cash consideration and purchase price adjustments used in our large acquisitions, for oil and natural gas properties (e.g. drilling and completion costs, acquisitions, and other capital expenditures) amounted to $519.3 million, while the actual cash spend in this regard amounted to $474.5 million.

Development and acquisition activities are discretionary. We monitor our capital expenditures on a regular basis, adjusting the amount up or down, and between projects, depending on projected commodity prices, cash flows and returns. Our cash spend for development and acquisition activities for the years ended December 31, 2018, 2017 and 2016 are summarized in the following table:

	Year Ended December 31,		
	2018	**2017**	**2016**
	(in millions)		
Drilling and Development Capital Expenditures	$ 216.0	$ 104.2	$ 71.7
Acquisition of Oil and Natural Gas Properties	257.8	14.4	20.0
Other Capital Expenditures	0.7	0.8	1.2
Total	$ 474.5	$ 119.4	$ 92.9

Development and acquisition activities are discretionary. We monitor our capital expenditures on a regular basis, adjusting the amount up or down, and between projects, depending on projected commodity prices, cash flows and returns.

Cash Flows from Financing Activities

Net cash provided by (used for) financing activities was $130.4 million, $142.0 million and $(7.8) million for the years ended December 31, 2018, 2017 and 2016, respectively. The cash provided by financing activities in 2018 was primarily related to $141.7 million in equity offerings, as well as a net increase in borrowings of $40.0 million during 2018 (see Note 4 to our financial statements). Additionally, we repurchased $22.2 million of common stock and spent $26.6 million in fees in connection with debt financing transactions in 2018. The cash provided by financing activities in 2017, as compared to 2016, was primarily related to repayments of $144.0 million on our prior revolving credit facility that was refinanced with $300.0 million from the term loan credit agreement.

Our long-term debt at December 31, 2018 was $830.2 million, which was comprised of $690.2 million in second lien notes due 2023 and $140.0 million of borrowings under our revolving credit facility. At December 31, 2018, we had $285.0 million of available borrowing capacity under our revolving credit facility.

Revolving Credit Facility

On October 5, 2018, we entered into a new $750.0 million revolving credit facility (the “Revolving Credit Facility”) with Royal Bank of Canada, as administrative agent, and the lenders from time to time party thereto. The revolving credit agreement will mature 5 years from the closing date, provided that the maturity date shall be 91 days prior to the scheduled maturity date of the Second Lien Notes.

The revolving credit agreement is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to Northern and our subsidiaries' (if any) oil and gas properties. The initial borrowing base is $425.0 million until the next scheduled redetermination. The borrowing base will be redetermined semiannually on or around April 1st and October 1st, with one interim "wildcard" redetermination available between scheduled redeterminations. The April 1st scheduled redetermination shall be based on a January 1st engineering report audited by a 3rd party (reasonably acceptable by the Agent).

At our option, borrowings under the revolving credit agreement shall bear interest at the base rate or LIBOR plus an applicable margin. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from 75 to 175 basis points, and the applicable margin for LIBOR loans ranges from 175 to 275 basis points, in each case depending on the percentage of the borrowing base utilized.

The revolving credit agreement contains negative covenants that limit our ability, among other things, to pay dividends, incur additional indebtedness, sell assets, enter into certain derivatives contracts, change the nature of our business or operations, merge, consolidate, or make certain types of investments. In addition, the revolving credit agreement requires that we comply with the following financial covenants: (i) as of the date of determination, the ratio of total net debt to EBITDAX (as defined in the revolving credit agreement) shall be no more than 4.00 to 1.00, measured on a pro forma rolling four quarter basis, and (ii) the current ratio (defined as consolidated current assets including unused amounts of the total commitments, but excluding non-cash assets under FASB ASC 815, divided by consolidated current liabilities excluding current non-cash obligations under FASB ASC 815 and current maturities under the revolving credit agreement and the Second Lien Notes (as defined in the revolving credit agreement)) shall not be less than 1.00 to 1.00.

Our obligations under the revolving credit agreement may be accelerated, subject to customary grace and cure periods, upon the occurrence of certain Events of Default (as defined in the revolving credit agreement). Such Events of Default include customary events for a financing agreement of this type, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of affirmative or negative covenants, defaults on other indebtedness of us or our subsidiaries, defaults related to judgments and the occurrence of a Change in Control (as defined in the revolving credit agreement).

Our obligations under the Revolving Credit Facility are secured by mortgages on not less than 85.0% of the value of proven reserves associated with the oil and gas properties included in the determination of the borrowing base. Additionally, we entered into a Guaranty and Collateral Agreement in favor of the Agent for the secured parties, pursuant to which our obligations under the revolving credit agreement are secured by a first priority security interest in substantially all of our assets.

Second Lien Notes due 2023

On May 15, 2018, we issued Second Lien Notes with an aggregate principal amount of $344.3 million (the "Original 2L Notes") in connection with the closing of the Exchange Agreement. On October 5, 2018, we issued an additional $350.0 million aggregate principal amount of Second Lien Notes (the "Additional 2L Notes"), the proceeds of which were used in connection with the retirement of our Term Loan Credit Facility. In addition, during 2018, we issued $0.9 million aggregate principal amount of Second Lien Notes pursuant to the interest payment-in-kind provisions thereof (the "2L PIK Notes" and, together with the Original 2L Notes and the Additional 2L Notes, the "Second Lien Notes").

The terms of the Second Lien Notes include those stated in the Indenture entered into on May 15, 2018 by us and Wilmington Trust, National Association, as trustee (the "Original 2L Indenture"), as amended by the First Supplemental

Indenture, dated September 18, 2018 (the “First Supplemental 2L Indenture”), and the Second Supplemental Indenture, dated October 5, 2018 (the “Second Supplemental 2L Indenture” and, together with the Original 2L Indenture and the First Supplemental 2L Indenture, the “2L Indenture”).

The Second Lien Notes are the senior secured obligations of Northern and rank equal in right of payment to all existing and future senior indebtedness of Northern and our subsidiaries. The Second Lien Notes are secured by second priority security interests in substantially all of our assets, subject to certain exceptions. The Second Lien Notes will be guaranteed by all of our direct and indirect subsidiaries that guarantee indebtedness under any other indebtedness for borrowed money of Northern or any of our subsidiary guarantors. As of December 31, 2018, we do not have any subsidiaries. The Second Lien Notes will mature on May 15, 2023.

Interest on the Second Lien Notes will accrue at a rate of 8.500% per annum payable in cash quarterly in arrears on the first day of each calendar quarter. Beginning on July 1, 2018, the interest rate increased by 1.000% per annum, which increase is payable in kind (the "PIK Component"). Commencing June 30, 2018, and as of each December 31st and June 30th thereafter, if our total debt to EBITDAX ratio is (i) less than 3.00 to 1.00 as of such date, the PIK Component shall cease accruing effective as of the next interest payment date, or (ii) greater than or equal to 3.00 to 1.00 as of such date or if we fail to deliver financial statements, the PIK Component shall continue to accrue (or, if then not accruing, automatically commence accruing as of the next interest payment date) and be payable quarterly. The PIK Component began accruing on June 30, 2018. Due to significant improvement in our leverage ratio, we expect that the PIK Component will stop accruing effective as of March 31, 2019. Thereafter, we will seek to maintain a leverage ratio such that the PIK Component does not begin accruing again, although there can be no assurance that this will be the case.

If we incur junior lien or unsecured debt with a cash interest rate in excess of 9.500%, the cash rate on the Second Lien Notes will be increased by such excess. Default interest will be payable in cash on demand at the then applicable interest rate plus 3.000% per annum.

We may redeem all or a portion of any of the Second Lien Notes at the following redemption prices during the following time periods (plus accrued and unpaid interest on the Second Lien Notes redeemed): (i) from and after May 15, 2018 until May 15, 2021, 104%, (ii) on and after May 15, 2021 until May 15, 2022, 102%, and (iii) on and after May 15, 2022, 100%; provided that any redemption of Second Lien Notes (or the acceleration of Second Lien Notes) prior to May 15, 2020 shall also be accompanied by a make whole premium. Subject to the terms of an intercreditor agreement, we are also required to offer to prepay the Second Lien Notes with 100% of the net cash proceeds of asset sales, casualty events and condemnations in excess of $20.0 million, subject to customary exclusions and reinvestment provisions. Mandatory prepayment offers will be subject to payment of the make whole premium and redemption price set forth above, as applicable.

If a change of control occurs, we will be required to offer to repurchase the Second Lien Notes at the repurchase price of 101% of the principal amount of repurchased Second Lien Notes (subject to the prepayment provisions of the term loan credit agreement). The Second Lien Notes contain negative covenants that limit our ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain derivatives contracts, change the nature of our business or operations, merge, consolidate, make certain types of investments, amend other debt documents, and incur any additional debt on a subordinated or junior basis to the term loan credit agreement and on a senior basis to the Second Lien Notes. The Second Lien Notes do not include any financial maintenance covenants.

Our obligations under the Second Lien Notes may be accelerated upon the occurrence of an Event of Default (as such term is defined in the 2L Indenture). Events of Default include customary events for a capital markets debt financing of this type, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of affirmative or negative covenants, defaults on other indebtedness of us or our subsidiaries, bankruptcy or related defaults, defaults related to judgments and the occurrence of a Change of Control (as such term is defined in the 2L Indenture).

Term Loan Credit Agreement

Our term loan credit agreement was retired and repaid in full in connection with refinancing transactions that closed on October 5, 2018. The description of the term loan credit agreement that follows is as it existed immediately prior to its retirement.

On November 1, 2017 (the "Effective Date"), we entered into a term loan credit agreement with TPG Specialty Lending, Inc., as administrative agent and collateral agent (in such capacities, the "Agent"), and the lenders from time to time party thereto. The term loan credit agreement, as amended, provides for the issuance of an aggregate principal amount of up to $500.0 million in term loans to us, consisting of (i) $300.0 million in initial term loans that were made on the Effective Date (the “Initial Loans”), (ii) $100.0 million in delayed draw term loans available to us, subject to satisfaction of certain conditions precedent described therein, for a period of 18-months after the Effective Date (the “Delayed Draw Loans”), and (iii) up to $100.0 million in incremental term loans on an uncommitted basis and subject, among other things, to one or more lenders agreeing in the future to make such loans (the “Incremental Loans”) (the Initial Loans, Delayed Draw Loans and the Incremental Loans, collectively, the “Loans”). Amounts borrowed and repaid under the term loan credit agreement could not be reborrowed. All borrowings under the term loan credit agreement were scheduled to mature on November 1, 2022. In addition to the $300.0 million in Initial Loans, we borrowed $60.0 million of Delayed Draw Loans on May 15, 2018.

Borrowings under the term loan credit agreement were subject to interest at a rate per annum equal to the "Adjusted LIBO Rate" (subject to a 1.00% floor) plus a 7.75% per annum margin. The "Adjusted LIBO Rate" was equal to the product of: (i) three-month LIBOR multiplied by (ii) the statutory reserve rate. Upon the occurrence and continuance of an event of default all outstanding Loans would bear interest at a rate equal to 3.00% per annum plus the then-effective rate of interest. Interest was payable on the last business day of each March, June, September and December.

A commitment fee was paid on the unused amount of the delayed draw commitments based on an annual rate of 2.00% (the "Commitment Fee"). Prepayments (including mandatory prepayments), terminations, refinancing, reductions and accelerations under the term loan credit agreement are subject to the payment of a yield maintenance amount for any such prepayment, termination, refinancing, reduction or acceleration occurring prior to May 15, 2020 (or, with respect to any Delayed Draw Loan, prior to the two-year anniversary of the funding of such Delayed Draw Loan) that allows the lenders to attain approximately the same yield as if such Loan remained outstanding for the entire two-year period, as applicable, plus a call protection amount equal to the product of the principal amount of Loans so prepaid, terminated, refinanced, reduced or accelerated multiplied by (i) 4.00% for any such prepayment, termination, refinancing, reduction or acceleration occurring, (A) with respect to the Initial Loans, on or prior to May 15, 2021, or (B) with respect to Delayed Draw Loans, on or prior to the 36-month anniversary of the funding of such Delayed Draw Loan, or (ii) 2.00% for any such prepayment, termination, refinancing, reduction or acceleration occurring, (A) with respect to the Initial Loans, after May 15, 2021 and on or prior to May 15, 2022, or (B) with respect to Delayed Draw Loans, after the 36-month anniversary but on or prior to the 48-month anniversary of the funding of such Delayed Draw Loan, in each case, as set forth in the term loan credit agreement. Additionally, to the extent that the Loans are refinanced in full or the delayed draw commitments are terminated or reduced prior to the date that is 18 months after the Effective Date, the Company will be required to pay a yield maintenance amount in respect of the Commitment Fee that would have accrued on the delayed draw commitments as set forth in the term loan credit agreement.

Our obligations under the term loan credit agreement were secured by mortgages on substantially all of the oil and gas properties of Northern subject to the limitations set forth in the term loan credit agreement. In connection with the term loan credit agreement, we entered into a guaranty and collateral agreement in favor of the Agent for the secured parties, pursuant to which our obligations under the term loan credit agreement and any swap agreements entered into with swap counterparties were secured by a first-priority security interest in substantially all of our assets.

Unsecured Notes due 2020

Our 8.000% senior unsecured notes due June 1, 2020 (the "Unsecured Notes") were subject to various exchange transactions during 2018 (described above). All remaining outstanding Unsecured Notes were redeemed and repaid in full on October 11, 2018. The description of the Unsecured Notes that follows is as of immediately prior to such final redemption.

On May 18, 2012, we issued at par value $300.0 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "Original Notes"). On May 13, 2013, we issued at a price of 105.25% of par an additional $200.0 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "2013 Follow-on Notes"). On May 18, 2015, we issued at a price of 95.000% of par an additional $200.0 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "2015 Mirror Notes" and, together with the Original Notes and the 2013 Follow-on Notes, the "Notes"). Interest is payable on the Notes semi-annually in arrears on each of June 1 and December 1. We currently do not have any subsidiaries and, as a result, the Notes are not currently guaranteed. Any subsidiaries we form in the future may be required to unconditionally guarantee, jointly and severally, payment obligation under the Notes on a senior unsecured basis. The issuance of the Original Notes resulted in net proceeds to us of approximately $291.2 million, the issuance of the 2013 Follow-on Notes resulted in net proceeds to us of approximately $200.1 million, and the issuance of the 2015 Mirror Notes resulted in net proceeds to us of approximately $184.9 million. Collectively, the net proceeds are in use to fund our exploration, development and acquisition program and for general corporate purposes.

On and after June 1, 2018, we may redeem some or all of the Notes at a redemption price (expressed as a percentage of principal amount) equal to 100%, plus accrued and unpaid interest to the redemption date.

The Original Notes and the 2013 Follow-on Notes were governed by an Indenture, dated as of May 18, 2012, by and among Northern and Wilmington Trust, National Association (the “Original Indenture”). The 2015 Mirror Notes were governed by an Indenture, dated as of May 18, 2015, by and among Northern and Wilmington Trust, National Association (the “Mirror Indenture”). The terms and conditions of the Mirror Indenture conform, in all material respects, to the terms and conditions set forth in the Original Indenture.

2019 Capital Expenditure Budget

Our board of directors has approved a capital expenditure budget for calendar year 2019. However, the amount, timing and allocation of capital expenditures are largely discretionary and subject to change based on a variety of factors. If oil, NGL and natural gas prices decline below our acceptable levels, or costs increase above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We will carefully monitor and may adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing and joint venture opportunities, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, reduction of service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control. For additional information on the impact of changing prices and market conditions on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Capital Requirements

Development and acquisition activities are discretionary, and, for the near term, we expect such activities to be maintained at levels we can fund through cash on hand, internal cash flow and borrowings under our revolving credit facility. To the extent capital requirements exceed internal cash flow and borrowing capacity under our revolving credit facility, additional financings from the capital markets may be pursued to fund these requirements. We monitor our capital expenditures on a regular basis, adjusting the amount up or down and also between our projects, depending on commodity prices, cash flow and projected returns. Also, our obligations may change due to acquisitions, divestitures and continued growth. Our future success in growing proved reserves and production may be dependent on our ability to access outside sources of capital. If internally generated cash flow and borrowing capacity is not available under our revolving credit facility, we may issue additional equity or debt to fund capital expenditures, acquisitions, extend maturities or to repay debt.

Satisfaction of Our Cash Obligations for the Next 12 Months

With our revolving credit agreement and our cash flows from operations, we believe we will have sufficient capital to meet our drilling commitments, expected general and administrative expenses and other cash needs for the next twelve months. Nonetheless, any strategic acquisition of assets or increase in drilling activity may require us to seek additional capital. We may also choose to seek additional capital rather than utilize our credit facility or other debt instruments to fund accelerated or continued drilling at the discretion of management and depending on prevailing market conditions. We will evaluate any potential opportunities for acquisitions as they arise. However, there can be no assurance that any additional capital will be available to us on favorable terms or at all.

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Contractual Obligations and Commitments

The following table summarizes our obligations and commitments at December 31, 2018 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods:

	Payment due by Period (in thousands)				
Contractual Obligations	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**	**Total**
Office Leases[1]	$ 352	$ 701	$ —	$ —	$ 1,053
Long Term Debt[2]	—	—	835,140	—	835,140
Cash Interest Expense on Debt[3]	65,292	195,875	92,103	—	353,270
Debt Exchange Derivative Liability[4]	18,335	—	—	—	18,335
Contingent Consideration[5]	58,662	—	—	—	58,662
Total	$ 142,641	$ 196,576	$ 927,243	$ —	$ 1,266,460

(1) Office leases through 2021
(2) Revolving Credit Facility and 8.5% Senior Secured Notes due 2023 (see Note 4 to our financial statements)
(3) Cash interest on our Revolving Credit Facility and 8.5% Senior Secured Notes due 2023 are estimated assuming no principal repayment until the due date.
(4) Amounts related to future consideration potentially payable by us pursuant to certain exchange agreements we entered into during 2018 with holders of our Unsecured Notes, as described under the heading “Additional Exchanges” in Note 4 to the Financial Statements. We are permitted in certain circumstances to settle amounts owed in either cash or shares of common stock. The amount included in the table above is the undiscounted expected value of the potential payments, based on Monte Carlo simulation models used to calculate the fair value of these liabilities as of December 31, 2018.
(5) Amounts related to contingent consideration potentially payable by us in connection with the W Energy Acquisition and the Pivotal Acquisition, as described in Note 3 to the Financial Statements. We are permitted in certain circumstances to settle amounts owed in either cash or shares of common stock. The amount included in the table above is the undiscounted expected value of the potential payments, based on Monte Carlo simulation models used to calculate the fair value of these liabilities as of December 31, 2018.

The above contractual obligations schedule does not include future anticipated settlement of derivative contracts or estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties, as we cannot determine with accuracy the amount and/or timing of such payments.

Critical Accounting Policies

The establishment and consistent application of accounting policies is a vital component of accurately and fairly presenting our financial statements in accordance with generally accepted accounting principles in the United States

(GAAP), as well as ensuring compliance with applicable laws and regulations governing financial reporting. While there are rarely alternative methods or rules from which to select in establishing accounting and financial reporting policies, proper application often involves significant judgment regarding a given set of facts and circumstances and a complex series of decisions.

Use of Estimates

The preparation of financial statements under GAAP requires management to make estimates and assumptions that affect our reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Our estimates of our proved oil and natural gas reserves, future development costs, estimates relating to certain oil and natural gas revenues and expenses and fair value of derivative instruments, debt derivative exchange liabilities, and contingent consideration liabilities are the most critical to our financial statements.

Oil and Natural Gas Reserves

The determination of depreciation, depletion and amortization expense as well as impairments that are recognized on our oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. Our estimate of proved reserves is based on the quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, production taxes and development costs, all of which may in fact vary considerably from actual results. In addition, as the prices of oil and natural gas and cost levels change from year to year, the economics of producing our reserves may change and therefore the estimate of proved reserves may also change. Approximately 44% of our proved oil and gas reserve volumes are categorized as proved undeveloped reserves. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Such information includes revisions of certain reserve estimates attributable to our properties included in the prior year's estimates. These revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in oil and natural gas prices.

External petroleum engineers independently estimated all of the proved reserve quantities included in our financial statements, and were prepared in accordance with the rules promulgated by the SEC. In connection with our external petroleum engineers performing their independent reserve estimations, we furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests. The independent petroleum engineers, Cawley, Gillespie & Associates, Inc., evaluated 100% of our estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2018.

Oil and Natural Gas Properties

The method of accounting we use to account for our oil and natural gas investments determines what costs are capitalized and how these costs are ultimately matched with revenues and expensed.

We utilize the full cost method of accounting to account for our oil and natural gas investments instead of the successful efforts method because we believe it more accurately reflects the underlying economics of our programs to explore and develop oil and natural gas reserves. The full cost method embraces the concept that dry holes and other expenditures that fail to add reserves are intrinsic to the oil and natural gas exploration business. Thus, under the full cost method, all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisitions, development and exploration activities, asset retirement costs, geological and geophysical costs that are directly attributable to the properties and capitalized interest. Although some of these costs will ultimately result in no additional reserves, they are part of a program from which we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. The full cost method differs from the successful efforts method of accounting for oil and natural gas investments. The primary difference between these two methods is the treatment of exploratory dry hole costs. These costs are generally expensed under the successful efforts method when it is determined that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are initially capitalized and classified as unproved properties pending determination of proved reserves. If no proved reserves are discovered, these costs are then amortized with all the costs in the full cost pool.

Capitalized amounts except unproved costs are depleted using the units of production method. The depletion expense per unit of production is the ratio of the sum of our unamortized historical costs and estimated future development costs to our proved reserve volumes. Estimation of hydrocarbon reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent reserve estimates materially different from those reported would change the depletion expense recognized during the future reporting periods. For the year ended December 31, 2018, our average depletion expense per unit of production was $12.75 per Boe. A 10% decrease in our estimated net proved reserves at December 31, 2018 would result in a $3.03 per Boe increase in our 12-month per unit depletion rate.

To the extent the capitalized costs in our full cost pool (net of depreciation, depletion and amortization and related deferred taxes) exceed the sum of the present value (using a 10% discount rate and based on 12-month/SEC oil and natural gas prices) of the estimated future net cash flows from our proved oil and natural gas reserves and the capitalized cost associated with our unproved properties, we would have a capitalized ceiling impairment. Such costs would be charged to operations as a reduction of the carrying value of oil and natural gas properties. The risk that we will be required to write down the carrying value of our oil and natural gas properties increases when oil and natural gas prices are depressed, even if the low prices are temporary. In addition, capitalized ceiling impairment charges may occur if we experience poor drilling results or if estimations of our proved reserves are substantially reduced. A capitalized ceiling impairment is a reduction in earnings that does not impact cash flows, but does impact operating income and stockholders' equity. Once recognized, a capitalized ceiling impairment charge to oil and natural gas properties cannot be reversed at a later date. The risk that we will experience a ceiling test writedown increases when oil and natural gas prices are depressed or if we have substantial downward revisions in our estimated proved reserves.

At December 31, 2018, we performed an impairment review using prices that reflect an average of 2018's monthly prices as prescribed pursuant to the SEC's guidelines. For the years ended December 31, 2018 and 2017, we did not record any full cost impairment expense. In 2016, we recorded a full cost impairment expense of $237.0 million. If a low price environment reoccurs, we might be required to further write down the value of our oil and gas properties. In addition, capitalized ceiling impairment charges may occur if estimates of proved reserves are substantially reduced or estimates of future development costs increase significantly. See "Item 2. Properties" for a discussion of our reserve estimation assumptions.

Revenue Recognition

We recognize revenue in accordance with FASB ASC Topic 606 – Revenue from Contracts with Customers, which we adopted effective January 1, 2018 using the modified retrospective approach. Refer to the "Significant Accounting Policies" footnote in the notes to the financial statements for more information on our adoption of this new accounting standard.

We derive revenue primarily from the sale of the crude oil and natural gas from our interests in producing wells. Revenue is recognized when we meet our performance obligation to deliver the product and control is transferred to the customer. We receive payment for product sales from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the amount of production delivered and the price we will receive can be reasonably estimated and amounts due from customers are accrued in accounts receivable trade, net in the balance sheets. Variances between our estimated revenue and actual payments are recorded in the month the payment is received. However, differences have been and are insignificant.

As of December 31, 2018, our natural gas production was in balance, meaning our cumulative portion of natural gas production taken and sold from wells in which we have an interest equaled our entitled interest in natural gas production from those wells.

Derivative Instrument Activities

We use derivative instruments from time to time to manage market risks resulting from fluctuations in the prices of oil and natural gas. We may periodically enter into derivative contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of oil or natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells. We may also use exchange traded futures contracts and option contracts to hedge the delivery price of oil at a future date.

All derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net on the statements of operations rather than as a component of accumulated other comprehensive income or other income (expense). See Note 13 to our financial statements for a description of the derivative contracts.

The resulting cash flows from derivatives are reported as cash flows from operating activities.

Income Taxes

As of December 31, 2018 and 2017, we had recorded $0.4 million and $0.8 million net deferred tax assets, respectively.

As part of the process of preparing the financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items such as derivative instruments, depletion, depreciation and amortization, and certain accrued liabilities for tax and financial accounting purposes. These differences and our net operating loss carry-forwards result in deferred tax assets and liabilities, which are included in our balance sheet. We must then assess, using all available negative and positive evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provision in the statement of operations.

Under accounting guidance for income taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (i) the more positive evidence is necessary and (ii) the more difficult it is to support a conclusion that a valuation allowance is not needed for all or a portion of the deferred tax asset. Among the more significant types of evidence that we consider are:

•our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition;

•the ability to recover our net operating loss carry-forward deferred tax assets in future years;

•the existence of significant proved oil and natural gas reserves;

•our ability to use tax planning strategies, such as electing to capitalize intangible drilling costs as opposed to expensing such costs;

•current price protection utilizing oil and natural gas hedges;

•current market prices for oil, NGL and natural gas; and

•future revenue and operating cost projections that indicate we will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures.

During 2018, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered all positive and negative evidence available. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. See Note 10 to our financial statements for additional discussion of our income taxes.

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (the “Act”) which made significant changes that affect the Company. The Act is a comprehensive tax reform bill containing a number of other provisions that either currently or in the future could impact the Company. The Company has completed the analysis of the Act and does not expect a material change due to the transition impacts. Any changes that do arise due to changes in interpretations of the Act, legislative action to address questions that arise because of the Act, changes in accounting standards for income taxes or related interpretations in response to the Act, or any updates or changes to estimates the Company has utilized to calculate the transition impacts will be disclosed in future periods as they arise. The effect of certain limitations effective for the tax year 2018 and forward, specifically related to the deductibility of executive compensation and interest expense, have been evaluated.

Asset Retirement Obligations ("ARO")

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and natural gas properties, this is the period in which the well is drilled or acquired. For midstream service assets, this is the period in which the asset is placed in service. The ARO represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and for oil and natural gas properties the capitalized cost is depreciated on the unit of production method or for midstream service assets depreciated over its useful life. The accretion expense is recorded in the line item "Accretion of asset retirement obligations" in our statement of operations.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Included in the fair value calculation are assumptions and judgments including the ultimate costs, inflation factors, credit-adjusted risk-free discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Business Combinations

We account for business combinations using the acquisition method, which is the only method permitted under FASB ASC Topic 805 – *Business Combinations*, and involves the use of significant judgment.

Under the acquisition method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess, if any, of the consideration given to acquire an entity over the net amounts assigned to its assets acquired and liabilities assumed is recognized as goodwill. The excess, if any, of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity is recognized immediately to earnings as a gain from bargain purchase.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities, and present values of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

The business combinations completed during the prior three years consisted of crude oil and natural gas properties. In general, the consideration we have paid to acquire these properties was entirely allocated to the fair value of the assets acquired and liabilities assumed at the time of acquisition and consequently, there was no goodwill nor any bargain purchase gains recognized on our business combinations.

Recently Issued or Adopted Accounting Pronouncements

For discussion of recently issued or adopted accounting pronouncements, see Notes to Financial Statements—Note 2. Significant Accounting Policies.

Off-Balance Sheet Arrangements

We currently do not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

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

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand and other factors. Historically, the markets for oil and natural gas have been volatile, and we believe these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue generally would have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil that also increase and decrease along with oil prices.

We enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil price volatility. All derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net on the statements of operations rather than as a component of other comprehensive income or other income (expense).

We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future production. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under our term loan credit agreement.

The following table summarizes our open commodity swap contracts as of December 31, 2018, by fiscal quarter.

Settlement Period	Oil (Barrels)	Weighted Average Price ($)
Swaps-Crude Oil		
2019:		
Q1	1,775,700	62.89
Q2	1,797,250	63.09
Q3	1,666,480	63.44
Q4	1,612,300	63.90
2020:		
Q1	1,301,300	61.67
Q2	1,119,300	60.81
Q3	947,600	61.11
Q4	817,880	60.15
2021:		
Q1	682,200	60.42
Q2	627,900	62.00

In addition to the open commodity price swap contracts we have entered into basis swap contracts. Basis swaps fix the price differential between a published index price and the applicable local index price under which our production is sold. The following table reflects open commodity basis swap contracts as of December 31, 2018.

Settlement Period	**Oil (Barrels)**	**Weighted Average Price ($)**
01/01/19 – 12/31/19	3,650,000	(2.41)

Interest Rate Risk

Our long-term debt as of December 31, 2018 is comprised of borrowings that contain fixed and floating interest rates. The Senior Secured Notes bear cash interest at an annual fixed rate of 8.5%, plus potential PIK interest at an annual fixed rate (if owed) of 1.0%. Our Revolving Credit Facility interest rate is a floating rate option that is designated by us within the parameters established by the underlying agreement. At our option, borrowings under the Revolving Credit Facility bear interest at the base rate or LIBOR, plus an applicable margin. The base rate is a rate per annum equal to the greatest of: (i) the agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from 75 to 175 basis points, and the applicable margin for LIBOR loans ranges from 175 to 275 basis points, in each case depending on the percentage of the borrowing base utilized. Interest payments are due under the Revolving Credit Facility in arrears, in the case of a loan based on LIBOR on the last day of the specified interest period and in the case of all other loans on the last day of each March, June, September and December. All outstanding principal is due and payable upon termination of the Revolving Credit Facility.

As a result, changes in interest rates can impact results of operations and cash flows. A 1% increase in short-term interest rates on our floating-rate debt outstanding at December 31, 2018 would cost us approximately $1.4 million in additional annual interest expense.

Other Market Risk

Contingent Consideration

As a result of both the W Energy Acquisition and the Pivotal Acquisition, described in Note 3 to the Financial Statements, we incurred liabilities related to the contingent consideration potentially payable by us. The amount of contingent consideration we are required to pay after December 31, 2018 is dependent on the average daily volume-weighted average price of our common stock for each month from January-October 2019 compared to specified monthly benchmarks in each applicable agreement.

The value of this liability is carried on our balance sheet as the contingent consideration liability, and is required to be adjusted to fair value at each reporting period. The fair value of these liabilities is determined using Monte Carlo simulation models. Significant inputs used in the fair value measurements include (i) our common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) volatility of our common stock, and (iv) expected average daily trading volumes. These measurements are considered Level 3 measurements within the fair value hierarchy. Changes in the fair value of these liabilities are included in other income (expense) in our statements of operations. As a result, any changes in the inputs will impact the fair value of these liabilities and could materially impact the amount of income or expense recorded each reporting period.

The aggregate fair value of these liabilities was $58.1 million as of December 31, 2018. The liability is highly sensitive to the price of our common stock at each valuation date. We estimate that a 10% decrease in our common stock price as of December 31, 2018 would have increased the aggregate fair value of these liabilities by approximately 6% as of such date, and that a 10% increase in our common stock price as of such date would have decreased the aggregate fair value of these liabilities by approximately 9% as of such date.

See Note 3 and Note 12 to our financial statements for additional information regarding these contingent consideration liabilities.

Debt Exchange Derivatives

During 2018, we entered into certain exchange agreements with holders of our Unsecured Notes, as described under the heading “Additional Exchange Transactions” in Note 4 to the Financial Statements. As a result of such exchange agreements, we incurred liabilities related to future consideration potentially payable by us. The amount of consideration we are required to pay after December 31, 2018 is dependent on the trading price of our common stock over specified measurement periods compared to specified benchmarks, as specified in each applicable exchange agreement.

The value of this liability is carried on our balance sheet as the debt exchange derivative liability, and is required to be adjusted to fair value at each reporting period. The fair value of these liabilities is determined using Monte Carlo simulation models. Significant inputs used in the fair value measurements include (i) our common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) volatility of our common stock, and (iv) expected average daily trading volumes. These measurements are considered Level 3 measurements within the fair value hierarchy. Changes in the fair value of these liabilities are included in other income (expense) in our statements of operations. As a result, any changes in the inputs will impact the fair value of these liabilities and could materially impact the amount of income or expense recorded each reporting period.

The aggregate fair value of these liabilities was $18.2 million as of December 31, 2018. The liability is highly sensitive to the price of our common stock at each valuation date. We estimate that a 10% decrease in our common stock price as of December 31, 2018 would have increased the aggregate fair value of these liabilities by approximately 13% as of such date.

See Note 4 and Note 12 to our financial statements for additional information regarding these debt exchange derivative liabilities.

Item 8. ***Financial Statements and Supplementary Data***

The financial statements and supplementary financial information required by this item are included on the pages immediately following the Index to Financial Statements appearing on page F-1.

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 maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosures.

As of December 31, 2018, our management, including our principal executive officer and principal financial officer, had evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) pursuant to Rule 13a-15(b) under the Exchange Act. Based upon and as of the date of the evaluation, our principal executive officer and principal financial officer concluded that information required to be disclosed is recorded, processed, summarized and reported within the specified periods and is accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure of material information required to be included in our periodic SEC reports. Based on the foregoing, our management determined that our disclosure controls and procedures were effective as of December 31, 2018.

No change in our company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2018, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

The management of Northern Oil and Gas, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our Company's financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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 or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (2013).

Based on our evaluation under the framework in Internal Control-Integrated Framework, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of our Company's internal control over financial reporting as of December 31, 2018, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Northern Oil and Gas, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Northern Oil and Gas, Inc. (the "Company") as of December 31, 2018, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the financial statements as of and for the year ended December 31, 2018, of the Company and our report dated March 18, 2019, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's 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. A company's 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, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and 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. 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 or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
March 18, 2019

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

None.

PART III
Certain information required by this Part III is incorporated by reference from our definitive Proxy Statement for the Annual Meeting of Shareholders to be held in 2019 (the "Proxy Statement"), which we intend to file with the SEC pursuant to Regulation 14A within 120 days after December 31, 2018. Except for those portions specifically incorporated into this Annual Report on Form 10-K by reference to the Proxy Statement, no other portions of the Proxy Statement are deemed to be filed as part of this Annual Report on Form 10-K.

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

The information appearing under the headings "Proposal 1: Election of Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement is incorporated herein by reference.

We have adopted a Code of Business Conduct and Ethics that applies to our chief executive officer, chief financial officer and persons performing similar functions. A copy is available on our website at www.northernoil.com. We intend to post on our website any amendments to, or waivers from, our Code of Business Conduct and Ethics pursuant to the rules of the SEC and NYSE American.

Executive Officers of the Registrant

Our executive officers, their ages and offices held are as follows:

Name	**Age**	**Positions**
Brandon Elliott	47	Chief Executive Officer
Michael Reger	42	President
Nicholas O'Grady	40	Chief Financial Officer
Chad Allen	37	Chief Accounting Officer
Adam Dirlam	35	Executive Vice President, Land
Erik Romslo	41	Executive Vice President, General Counsel and Secretary

Brandon Elliott has served as our Chief Executive Officer since July 2018, prior to which he served as our Interim President in 2018 and as our Executive Vice President, Corporate Development and Strategy since January 2013. Prior to joining our company, Mr. Elliott served as Vice President of Investor Relations of CONSOL Energy Inc., a Fortune 500 coal and natural gas company, from 2010 until 2012. Prior to CONSOL, Mr. Elliott worked from

2000 until 2010 at Friess Associates LLC, managers of The Brandywine Funds, most recently as a portfolio manager. Mr. Elliott holds a bachelor’s degree from Dartmouth College, is a Chartered Financial Analyst (CFA) and is a member of the National Investor Relations Institute.

Michael Reger has served as our President since July 2018. Mr. Reger was the founder of our company in 2006 and served as the company’s CEO and Chairman until 2016. Mr. Reger returned to the company as Chairman Emeritus in 2017 and was named Advisor to the Board in January of 2018. Mr. Reger is a third generation Williston Basin landman from Billings, Montana, beginning his career as an oil and gas landman in 1992. Mr. Reger holds a bachelor's degree in finance and a master's degree in finance/management from the University of St. Thomas in St. Paul, Minnesota

Nicholas O'Grady has served as our Chief Financial Officer since June 2018. Mr. O’Grady has nearly two decades of finance experience, both as an investment banker and as a principal investor. Mr. O’Grady began his career in the Natural Resources investment banking group at Bank of America. Later moving to the hedge fund industry, he worked at firms such as Highbridge Capital Management. Prior to joining our company, he worked as a portfolio manager at Hudson Bay Capital Management from September 2014 to May 2018, where he focused on energy-related equities, public credit, private and direct investments. Previously, he worked as a portfolio manager at Bluecrest Capital Management from November 2013 to June 2014, and at Sigma Capital Management from April 2012 to October 2013. Mr. O’Grady holds a bachelor's degree in both history and economics from Bowdoin College in Brunswick, Maine.

Chad Allen has served as our Chief Accounting Officer since August 2016, prior to which he served as our Corporate Controller since joining Northern in August 2013. Mr. Allen served as the Company’s Interim Chief Financial Officer from January-May 2018. Prior to joining our company, Mr. Allen was in the audit practice with Grant Thornton LLP from 2010 to 2013, and in the audit practice at McGladrey & Pullen, LLP from 2004 to 2010. Mr. Allen holds a bachelor's degree in accounting from Minnesota State University, Mankato and is a Certified Public Accountant.

Adam Dirlam has served as Executive Vice President of Land & Operations since June 2018, prior to which he served as our Senior Vice President of Land & Operations since 2013 and other various roles with us since 2009. Prior to joining our company, Mr. Dirlam served in various finance and accounting roles for Honeywell International. Mr. Dirlam holds a bachelor’s degree from the University of St. Thomas and a master’s degree from the University of Minnesota - Carlson School of Management.

Erik Romslo has served as our General Counsel and Secretary since October 2011 and as an Executive Vice President since January 2013. Prior to joining our company, Mr. Romslo practiced law in the Minneapolis office of our outside counsel, Faegre Baker Daniels LLP (formerly Faegre & Benson LLP), from 2005 until 2011, where he was a member of the Corporate group. Prior to joining Faegre, Mr. Romslo practiced law in the New York City office of Fried, Frank, Harris, Shriver & Jacobson LLP. Mr. Romslo holds a bachelor’s degree from St. Olaf College and a law degree from the New York University School of Law.

Director or Executive Officer Involvement in Certain Legal Proceedings

Mr. Reger is subject to a cease-and-desist order (Release Nos. 33-10241 and 34-79194; Administrative Proceeding File No. 3-17653) that was entered by the Securities and Exchange Commission (the “Commission”) on October 31, 2016. The order is based on facts unrelated to our company or its operations. Mr. Reger consented to the order without admitting or denying the allegations. Pursuant to the order, he was required to (i) cease and desist from committing or causing any violations and any future violations of Sections 17(a)(2) and 17(a)(3) of the Securities Act and Sections 13(d) and 16(a) of the Exchange Act and (ii) pay to the Commission the amounts set forth in the order.

Item 11. *Executive Compensation*

The information appearing under the headings “Executive Compensation” and “Compensation Committee Report,” and the information regarding compensation committee interlocks and insider participation under the heading “Corporate Governance,” in the Proxy Statement is incorporated herein by reference.

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

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information with respect to our common shares issuable under our equity compensation plans as of December 31, 2018:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders			
2018 Equity Incentive Plan	—	—	15,669,775
Equity compensation plans not approved by security holders	—	—	—
Total	—	$ —	15,669,775

The information appearing under the heading "Security Ownership of Certain Beneficial Owners and Management" in the Proxy Statement is incorporated herein by reference.

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

The information appearing under the headings "Certain Relationships and Related Transactions" and "Corporate Governance" in the Proxy Statement is incorporated herein by reference.

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

The information appearing under the headings "Registered Public Accountant Fees" and "Pre-Approval Policies and Procedures of Audit Committee" in the Proxy Statement is incorporated herein by reference.

PART IV
Item 15. ***Exhibits and Financial Statement Schedules***

(a) Documents filed as part of this Report:

1	*Financial Statements* See Index to Financial Statements on page F-1.
2	*Financial Statement Schedules* All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(b) Exhibits:

Unless otherwise indicated, all documents incorporated by reference into this report are filed with the SEC pursuant to the Securities and Exchange Act of 1934, as amended, under file number 001-33999.

Exhibit No.	Description	Reference
2.1	Purchase and Sale Agreement, dated July 17, 2018, by and between Pivotal Williston Basin, LP and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 20, 2018
2.2	Purchase and Sale Agreement,	Incorporated by reference to Exhibit 2.2 to

	dated July 17, 2018, by and between Pivotal Williston Basin II, LP and Northern Oil and Gas, Inc.	the Registrant's Current Report on Form 8-K filed with the SEC on July 20, 2018
2.3	Purchase and Sale Agreement, dated July 27, 2018, by and between WR Operating LLC and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 31, 2018
2.4	First Amendment to Purchase and Sale Agreement, dated September 25, 2018, by and between WR Operating LLC and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 1, 2018
2.5	Share Repurchase Agreement, dated November 7, 2018, by and between W Energy Partners LLC and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 2.5 to the Amendment No. 1 to Registration Statement on Form S-3/A filed with the SEC on December 12, 2018 (file no. 333-227945)
2.6	Share Repurchase Agreement, dated November 1,	Incorporated by reference to Exhibit 2.6 to the Amendment

	2018, by and between Pivotal Williston Basin, LP and Northern Oil and Gas, Inc.	No. 1 to Registration Statement on Form S-3/A filed with the SEC on December 12, 2018 (file no. 333-227945)
2.7	Share Repurchase Agreement, dated November 1, 2018, by and between Pivotal Williston Basin II, LP and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 2.7 to the Amendment No. 1 to Registration Statement on Form S-3/A filed with the SEC on December 12, 2018 (file no. 333-227945)
3.1	Restated Certificate of Incorporation of Northern Oil and Gas, Inc. dated August 24, 2018	Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 27, 2018
3.2	By-Laws of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 15, 2018
4.1	Indenture, dated May 18, 2012, between Northern Oil and Gas, Inc. and Wilmington Trust, National	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May

	Association, as trustee (including Form of 8.000% Senior Note due 2020)	18, 2012
4.2	Indenture, dated May 18, 2015, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.000% Senior Note due 2020)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2015

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4.3	Indenture, dated May 15, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.50% Senior Secured Second Lien Notes due 2023)	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018
4.4	First Supplemental Indenture, dated September 18, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 18, 2018
4.5	Second Supplemental Indenture, dated October 5, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee	Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 9, 2018
10.1	Exchange Agreement, dated January 31, 2018, by and among Northern Oil and Gas, Inc. and the Noteholders party thereto	Incorporated by reference to Exhibit 10.24 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 23, 2018
10.2		

	First Amendment to Exchange Agreement, dated March 20, 2018, by and among Northern Oil and Gas, Inc., and the Noteholders party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on March 21, 2018
10.3	Second Amendment to Exchange Agreement, dated April 2, 2018, by and among Northern Oil and Gas, Inc., and the Noteholders party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on April 4, 2018
10.4	Term Loan Credit Agreement, dated November 1, 2017, among Northern Oil and Gas, Inc., TPG Specialty Lending, Inc. and the Lenders party hereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on November 2, 2017
10.5	Limited Waiver and Amendment to Credit Agreement, dated March 18, 2018, by and among Northern Oil and Gas, Inc., the lenders party thereto and TPG Specialty Lending, Inc., as administrative agent and collateral agent	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on March 19, 2018
10.6	Second Amendment to	Incorporated by reference to

	Term Loan Credit Agreement, dated May 15, 2018, by and among Northern Oil and Gas, Inc., the lenders party thereto and TPG Specialty Lending, Inc., as administrative agent and collateral agent	Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018
10.7	Third Amendment to Term Loan Credit Agreement, dated July 19, 2018, by and among Northern Oil and Gas, Inc., the lenders party thereto and TPG Specialty Lending, Inc., as administrative agent and collateral agent	Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 10-Q filed with the SEC on August 9, 2018
10.8	Amended and Restated Credit Agreement, dated October 5, 2018, among Northern Oil and Gas, Inc., Royal Bank of Canada, as administrative agent, and the lenders from time to time party thereto	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 9, 2018
10.9	Corrective Amendment to Amended and Restated Credit Agreement, dated October 31, 2018, by and	Filed herewith

	among Northern Oil and Gas, Inc. and Royal Bank of Canada	
10.10	First Amendment to Amended and Restated Credit Agreement, dated December 31, 2018, by and among Northern Oil and Gas, Inc., Royal Bank of Canada, and the Lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 4, 2019
10.11	Letter Agreement, dated January 2, 2015 by and among Robert B. Rowling, Cresta Investments, LLC, Cresta Greenwood, LLC, TRT Holdings, Inc. and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 5, 2015
10.12	Letter Agreement, dated January 25, 2017 by and among TRT Holdings, Inc., Cresta Investments, LLC, Cresta Greenwood, LLC, Robert Rowling, Michael Popejoy, Michael Frantz and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on January 27, 2017
10.13	Amended and Restated Letter Agreement,	Incorporated by reference to Exhibit 10.1 to

dated as of May 15, 2018, by and among Robert B. Rowling, Cresta Investments, LLC, Cresta Greenwood, LLC, TRT Holdings, Inc., Bahram Akradi and Northern Oil and Gas, Inc.	the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018

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10.14	Letter Agreement, dated July 21, 2017, by and between Northern Oil and Gas, Inc. and Bahram Akradi	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 24, 2017
10.15	Registration Rights Agreement, dated as of May 15, 2018, among Northern Oil and Gas, Inc. and the holders party thereto	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018
10.16	Registration Rights Agreement, dated as of May 15, 2018, among Northern Oil and Gas, Inc. and TRT Holdings, Inc., Cresta Investments, LLC and Cresta Greenwood, LLC	Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018
10.17	Registration Rights Agreement, dated as of May 15, 2018, among Northern Oil and Gas, Inc. and TPG Specialty Lending, Inc., TOP III Finance 1, LLC and TAO Finance 1, LLC	Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018
10.18		

	Registration Right Agreement, dated October 5, 2018, between Northern Oil and Gas, Inc. and RBC Capital, LLC, as representative of the Initial Purchasers	Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed with the SEC on October 9, 2018
10.19	Registration Rights Agreement, dated September 17, 2018, between Pivotal Williston Basin, LP, Pivotal Williston Basin II, LP, and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 18, 2018
10.20	Registration Rights Agreement, dated October 1, 2018, by and between WR Operating LLC and Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on October 1, 2018
10.21*	Amended and Restated Employment Agreement, dated May 24, 2018, between Northern Oil and Gas, Inc. and Michael Reger	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 31, 2018
10.22*	Amended and Restated Employment	Incorporated by reference to Exhibit

	Agreement, dated July 5, 2018, between Northern Oil and Gas, Inc. and Michael Reger	10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 6, 2018
10.23*	Employment Agreement, dated May 24, 2018, between Northern Oil and Gas, Inc. and Nicholas O'Grady	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 31, 2018
10.24*	Amended and Restated Employment Agreement, dated June 1, 2018, between Northern Oil and Gas, Inc. and Erik Romslo	Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on June 7, 2018
10.25*	Amended and Restated Employment Agreement, dated June 1, 2018, between Northern Oil and Gas, Inc. and Chad Allen	Incorporated by reference to Exhibit 10.13 to the Registrant's Current Report on Form 10-Q filed with the SEC on August 9, 2018
10.26*	Amended and Restated Employment Agreement, dated June 1, 2018, between Northern Oil and Gas, Inc. and	Incorporated by reference to Exhibit 10.14 to the Registrant's Current Report on Form 10-Q

	Adam Dirlam	filed with the SEC on August 9, 2018
10.27*	Amended and Restated Employment Agreement, dated July 5, 2018, between Northern Oil and Gas, Inc. and Brandon Elliott	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on July 6, 2018
10.28*	Northern Oil and Gas, Inc. 2013 Incentive Plan (as amended May 26, 2016)	Incorporated by reference to Appendix B to the Registrant's Definitive Proxy Statement filed with the SEC on April 22, 2016
10.29*	Form of Restricted Stock Award Agreement (Single Trigger) under the Northern Oil and Gas, Inc. 2013 Incentive Plan	Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 10-Q filed with the SEC on August 9, 2013
10.30*	Form of Restricted Stock Award Agreement (Double Trigger) under the Northern Oil and Gas, Inc. 2013 Incentive Plan	Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 10-Q filed with the SEC on August 9,

		2013
10.31*	Form of Restricted Stock Award Agreement (Performance Based) under the Northern Oil and Gas, Inc. 2013 Incentive Plan	Incorporated by reference to Exhibit 10.15 to the Registrant's Current Report on Form 10-Q filed with the SEC on August 9, 2018
10.32*	Form of Non-Qualified Stock Option Agreement for Non-Employee Director under the Northern Oil and Gas, Inc. 2013 Incentive Plan	Incorporated by reference to Exhibit 10.18 to the Registrant's Annual Report on Form 10-K filed with the SEC on March 3, 2016

10.33*	Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Incorporated by reference to Exhibit 99.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 27, 2018
10.34*	Form of Restricted Stock Award Agreement (Time-Based Single Trigger) under the Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Filed herewith
10.35*	Form of Restricted Stock Award Agreement (Time-Based Double Trigger) under the Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Filed herewith
10.36*	Form of Restricted Stock Award Agreement (Performance-Based Employees) under the Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Filed herewith
10.37*	Form of Restricted Stock Award Agreement (Performance-Based Directors) under the Northern Oil and Gas, Inc. 2018 Equity Incentive Plan	Filed herewith
10.38	Purchase Agreement, dated September 21, 2018, by and between Northern Oil and Gas,	Incorporated by reference to Exhibit 10.1 to the

	Inc. and RBC Capital Markets, LLC, as representative of the initial purchasers named therein	Registrant's Current Report on Form 8-K filed with the SEC on September 25, 2018
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP	Filed herewith
23.2	Consent of Independent Registered Public Accounting Firm Grant Thornton LLP	Filed herewith
23.3	Consent of Cawley, Gillespie & Associates, Inc.	Filed herewith
23.4	Consent of Ryder Scott, LP	Filed herewith
24.1	Powers of Attorney	Filed herewith (included on signature page)
31.1	Certification of the Principal Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith
31.2	Certification of the Principal Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the	Filed herewith

	Sarbanes-Oxley Act of 2002	
32.1	Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Filed herewith
99.1	Report of Cawley, Gillespie & Associates	Filed herewith
101.INS	XBRL Instance Document	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema Document	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith

* Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report.

Item 16. ***Form 10-K Summary***

None.

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.

NORTHERN OIL AND GAS, INC.

Date:	March 18, 2019	By:	/s/ Brandon Elliott
			Brandon Elliott, Chief Executive Officer; Principal Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints, Brandon Elliott and Nicholas O'Grady, or either of them, his/her true and lawful attorney-in-fact and agent, acting alone, with full power of substitution and resubstitution, for him/her and in his/her name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Annual Report on Form 10-K and to file the same, with all exhibits thereto, and other documents in connection wherewith, with the Commission, granting unto said attorney-in-fact and agent, each acting alone, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all said attorney-in-fact and agent, acting alone, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated:

Signature	**Title**	**Date**
/s/ Brandon Elliott	Chief Executive Officer, Principal Executive Officer	March 18, 2019
Brandon Elliott		
/s/ Nicholas O'Grady	Chief Financial Officer, Principal Financial Officer	March 18, 2019
Nicholas O'Grady		

/s/ Chad Allen Chad Allen	Chief Accounting Officer, Principal Accounting Officer	March 18, 2019
/s/ Bahram Akradi Bahram Akradi	Director	March 18, 2019
/s/ Jack King Jack King	Director	March 18, 2019
/s/ Robert Grabb Robert Grabb	Director	March 18, 2019
/s/ Lisa Bromiley Lisa Bromiley	Director	March 18, 2019
/s/ Roy Easley Roy Easley	Director	March 18, 2019
/s/ Michael Frantz Michael Frantz	Director	March 18, 2019
/s/ Michael Popejoy Michael Popejoy	Director	March 18, 2019

/s/ Joseph Lenz	Director	March 18, 2019
Joseph Lenz		

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NORTHERN OIL AND GAS, INC.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Northern Oil and Gas, Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheet of Northern Oil and Gas, Inc. (the “Company”) as of December 31, 2018, the related statement of operations, statement of stockholders’ equity, and cash flows for the year ended December 31, 2018, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of its operations and its cash flows the year ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company’s internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 18, 2019, expressed an unqualified opinion on the Company’s internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the 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 financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the 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 financial statements. We believe that our audits provides a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
March 18, 2019

We have served as the Company’s auditor since 2018.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Northern Oil and Gas, Inc.

Opinion on the financial statements
We have audited the accompanying balance sheet of Northern Oil and Gas, Inc. (a Delaware corporation) (the "Company") as of December 31, 2017, the related statements of operations, stockholders' equity (deficit), and cash flows for the years ended December 31, 2017 and 2016, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for the years ended December 31, 2017 and 2016, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the 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 financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We served as the Company's auditor from 2015 to 2018.

2Minneapolis, Minnesota
February 23, 2018

NORTHERN OIL AND GAS, INC.
BALANCE SHEETS

	December 31, 2018		December 31, 2017	
ASSETS				
Current Assets:				
Cash and Cash Equivalents	$	2,357,858	$	102,183,191
Accounts Receivable, Net	96,352,918		46,851,682	
Advances to Operators	268,494		604,977	
Prepaid Expenses and Other	12,360,027		2,333,288	
Derivative Instruments	115,870,246		—	
Income Tax Receivable	1,205,016		785,016	
Total Current Assets	228,414,559		152,758,154	
Property and Equipment:				
Oil and Natural Gas Properties, Full Cost Method of Accounting				
Proved	3,431,427,768		2,585,490,133	
Unproved	4,306,513		1,699,344	
Other Property and Equipment	998,192		981,303	
Total Property and Equipment	3,436,732,473		2,588,170,780	
Less – Accumulated Depreciation, Depletion and Impairment	(2,233,987,232)		(2,114,951,189)	
Total Property and Equipment, Net	1,202,745,241		473,219,591	
Derivative Instruments	61,842,846		—	
Deferred Income Taxes	420,000		785,000	
Other Noncurrent Assets, Net	10,222,659		5,490,934	
Total Assets	$	1,503,645,305	$	632,253,679
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)				
Current Liabilities:				
Accounts Payable	$	135,482,513	$	93,152,297
Accrued Expenses	2,769,438		6,339,425	
Accrued Interest	16,467,628		4,836,112	
Debt Exchange Derivative	18,183,212		—	
Derivative Instruments	—		18,681,891	
Contingent Consideration	58,068,917		—	
Asset Retirement Obligations	554,589		565,521	
Total Current Liabilities	231,526,297		123,575,246	
Long-term Debt, Net	830,203,272		979,324,222	
Derivative Instruments	—		11,496,929	

Asset Retirement Obligations	11,946,271		8,562,607	
Other Noncurrent Liabilities	104,582		135,225	
TOTAL LIABILITIES	1,073,780,422		1,123,094,229	
COMMITMENTS AND CONTINGENCIES				
STOCKHOLDERS' EQUITY (DEFICIT)				
Preferred Stock, Par Value $.001; 5,000,000 Authorized, No Shares Outstanding	—		—	
Common Stock, Par Value $.001; 675,000,000 Authorized (12/31/2018 – 378,333,070 Shares Outstanding and 12/31/2017 – 142,500,000 Authorized, 66,791,633 Shares Outstanding)	378,333		66,792	
Additional Paid-In Capital	1,226,371,047		449,666,390	
Retained Deficit	(796,884,497)		(940,573,732)	
Total Stockholders' Equity (Deficit)	429,864,883		(490,840,550)	
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$	1,503,645,305	$	632,253,679

The accompanying notes are an integral part of these financial statements.

NORTHERN OIL AND GAS, INC.
STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016

	December 31,		
	2018	2017	2016
REVENUES			
Oil and Gas Sales	$ 493,909,268	$ 223,963,010	$ 159,690,883
Gain (Loss) on Derivative Instruments, Net	185,006,169	(14,666,655)	(14,818,734)
Other Revenue	9,059	23,314	31,347
Total Revenues	678,924,496	209,319,669	144,903,496
OPERATING EXPENSES			
Production Expenses	66,646,080	49,732,861	45,680,110
Production Taxes	45,301,892	20,604,256	15,513,608
General and Administrative Expense	14,568,362	18,987,801	14,757,641
Depletion, Depreciation, Amortization and Accretion	119,779,675	59,500,155	61,244,158
Impairment of Oil and Natural Gas Properties	—	—	237,012,834
Total Expenses	246,296,009	148,825,073	374,208,351
INCOME (LOSS) FROM OPERATIONS	432,628,487	60,494,596	(229,304,855)
OTHER INCOME (EXPENSE)			
Interest Expense, Net of Capitalization	(86,005,183)	(70,286,341)	(64,485,623)
Write-off of Debt Issuance Costs	—	(95,135)	(1,089,507)
Loss on the Extinguishment of Debt	(173,430,042)	(992,950)	—
Debt Exchange Derivative Loss	(598,124)	—	—
Contingent Consideration Loss	(28,968,176)	—	—
Financing Expense	(883,698)	—	—
Other Income (Expense)	890,971	116,042	(15,902)
Total Other Income (Expense)	(288,994,252)	(71,258,384)	(65,591,032)
INCOME (LOSS) BEFORE INCOME TAXES	143,634,235	(10,763,788)	(294,895,887)
INCOME TAX BENEFIT	(55,000)	(1,570,016)	(1,402,179)

NET INCOME (LOSS)	$	143,689,235	$	(9,193,772)	$	(293,493,708)
Net Income (Loss) Per Common Share – Basic	$	0.61	$	(0.15)	$	(4.80)
Net Income (Loss) Per Common Share – Diluted	$	0.61	$	(0.15)	$	(4.80)
Weighted Average Shares Outstanding – Basic	236,206,457		62,408,855		61,173,547	
Weighted Average Shares Outstanding – Diluted	236,773,911		62,408,855		61,173,547	

The accompanying notes are an integral part of these financial statements.

NORTHERN OIL AND GAS, INC.
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016

	December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income (Loss)	$ 143,689,235	$ (9,193,772)	$ (293,493,708)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Depletion, Depreciation, Amortization and Accretion	119,779,675	59,500,155	61,244,158
Amortization of Debt Issuance Costs	5,147,101	4,122,226	3,822,967
Write-off of Debt Issuance Costs	—	95,135	1,089,507
Loss on Extinguishment of Debt	173,430,042	992,950	—
Amortization of Bond (Premium) Discount on Long-term Debt	(563,485)	495,892	501,324
(Gain) Loss on the Sale of Other Property & Equipment	—	—	30,356
Deferred Income Taxes	365,000	(785,000)	—
(Gain) Loss on the Mark-to-Market of Derivative Instruments	(207,891,912)	18,443,443	76,346,935
Legal Settlement	—	2,820,000	—
Loss on Debt Exchange Derivative	598,124	—	—
Loss on Contingent Consideration	28,968,176	—	—
PIK Interest on Second Lien Notes	2,598,548	—	—
Share-Based Compensation Expense	3,995,476	3,286,566	3,464,040
Impairment of Oil and Natural Gas Properties	—	—	237,012,834
Other	(119,965)	31,623	373,983
Changes in Working Capital and Other Items:			
Accounts Receivable, Net	(49,122,498)	(9,717,487)	15,604,984
Prepaid and Other Expenses	19,397,512	(749,159)	(691,261)
Accounts Payable	(2,284,002)	2,611,492	(365,103)
Accrued Interest	10,212,130	142,318	(90,593)
Accrued Expenses	(3,516,958)	253,517	(1,556,673)
Income Tax Payable/(Receivable)	(420,000)	617,163	(1,402,179)

Net Cash Provided By Operating Activities	244,262,199	72,967,062	101,891,571
CASH FLOWS FROM INVESTING ACTIVITIES			
Drilling and Development Capital Expenditures	(216,692,159)	(104,997,637)	(72,944,035)
Acquisition of Oil and Natural Gas Properties	(257,807,335)	(14,409,607)	(19,991,870)
Proceeds from Sale of Oil and Natural Gas Properties	21,689	171,451	2,172,003
Proceeds from Sale of Other Property and Equipment	46,000	—	14,500
Purchases of Other Property and Equipment	(86,783)	(3,954)	(214,685)
Net Cash Used For Investing Activities	(474,518,588)	(119,239,747)	(90,964,087)
CASH FLOWS FROM FINANCING ACTIVITIES			
Advances on Revolving Credit Facility	190,000,000	36,000,000	63,000,000
Repayments on Revolving Credit Facility	(50,000,000)	(180,000,000)	(69,000,000)
Borrowings on Term Loan Credit Agreement	60,000,000	300,000,000	—
Repayments on Term Loan Credit Agreement	(420,105,000)	—	—
Issuance of Second Lien Notes	364,369,444	—	—
Repayments of Senior Unsecured Notes	(104,214,673)	—	—
Debt Issuance Costs Paid	(26,648,611)	(13,361,833)	(428,515)
Debt Derivative Exchange Settlements	(1,769,094)	—	—
Issuance of Common Stock	141,673,861	—	—
Repurchases of Common Stock	(22,195,035)	—	—
Restricted Stock Surrenders - Tax Obligations	(679,836)	(668,389)	(1,403,260)
Net Cash Provided By (Used For) Financing Activities	130,431,056	141,969,778	(7,831,775)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(99,825,333)	95,697,093	3,095,709
CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	102,183,191	6,486,098	3,390,389
CASH AND CASH EQUIVALENTS –	$ 2,357,858	$ 102,183,191	$ 6,486,098

END OF PERIOD

The accompanying notes are an integral part of these financial statements.

NORTHERN OIL AND GAS, INC.
STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)
FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016

	Common Stock			**Additional Paid-In**	**Retained Earnings**	**Total Stockholders' Equity**
	Shares	**Amount**	**Capital**	**(Deficit)**	**(Deficit)**	
December 31, 2015	63,120,384	63,121	440,221,018	(637,886,252)	(197,602,113)	
Issuance of Common Stock	2,109,814	2,110	—	—	2,110	
Restricted Stock Forfeitures	(1,594,542)	(1,595)	(2,154,277)	—	(2,155,872)	
Share Based Compensation	—	—	7,231,175	—	7,231,175	
Restricted Stock Surrenders - Tax Obligations	(375,875)	(376)	(1,402,884)		(1,403,260)	
Net Loss	—	—	—	(293,493,708)	(293,493,708)	
December 31, 2016	63,259,781	63,260	443,895,032	(931,379,960)	(487,421,668)	
Issuance of Common Stock	3,911,355	3,911	2,817,000	—	2,820,911	
Restricted Stock Forfeitures	(108,993)	(109)	(23,588)	—	(23,697)	
Share Based Compensation	—	—	3,646,065	—	3,646,065	
Restricted Stock Surrenders - Tax Obligations	(270,510)	(270)	(668,119)	—	(668,389)	
Net Loss	—	—	—	(9,193,772)	(9,193,772)	
December 31, 2017	66,791,633	66,792	449,666,390	(940,573,732)	(490,840,550)	
Issuance of Common Stock	3,295,302	3,295	—	—	3,295	
Restricted Stock Forfeitures	(910,086)	(910)	—	—	(910)	
Share Based Compensation	—	—	4,361,933	—	4,361,933	
Restricted Stock Surrenders - Tax Obligations	(266,683)	(267)	(679,569)	—	(679,836)	
Equity Offerings	96,926,019	96,926	141,576,935	—	141,673,861	
Debt Exchange Agreements	136,063,799	136,064	327,363,354	—	327,499,418	
	83,730,539	83,730	326,269,742	—	326,353,472	

Acquisition of Oil and Natural Gas Properties					
Net Exercise of Stock Options	62,500	63	(63)	—	—
Repurchases of Common Stock	(7,359,953)	(7,360)	(22,187,675)	—	(22,195,035)
Net Income	—	—	—	143,689,235	143,689,235
December 31, 2018	$ 378,333,070	$ 378,333	$ 1,226,371,047	$ (796,884,497)	$ 429,864,883

The accompanying notes are an integral part of these financial statements.
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NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 2018

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Northern Oil and Gas, Inc. (the "Company," "Northern," "our" and words of similar import), a Delaware corporation, is an independent energy company engaged in the acquisition, exploration, exploitation, development and production of crude oil and natural gas properties. The Company's common stock trades on the NYSE American market under the symbol "NOG".

Northern's principal business is crude oil and natural gas exploration, development, and production with operations in North Dakota and Montana that primarily target the Bakken and Three Forks formations in the Williston Basin of the United States. The Company acquires leasehold interests that comprise of non-operated working interests in wells and in drilling projects within its area of operations.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). In connection with preparing the financial statements for the year ended December 31, 2018, the Company has evaluated subsequent events for potential recognition and disclosure through the date of this filing and determined that there were no subsequent events which required recognition or disclosure in the financial statements through the date of this filing.

Use of Estimates

The preparation of financial statements under GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The most significant estimates relate to proved crude oil and natural gas reserves, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, fair value of continent consideration, acquisition date fair values of assets acquired and liabilities assumed, impairment of oil and natural gas properties, asset retirement obligations and deferred income taxes. Actual results may differ from those estimates.

Reclassifications

Certain prior period balances in the balance sheets have been reclassified to conform to the current year presentation. Such reclassifications had no impact on net loss, cash flows or stockholders' deficit previously reported.

Cash and Cash Equivalents

Northern considers highly liquid investments with insignificant interest rate risk and original maturities to the Company of three months or less to be cash equivalents. Cash equivalents consist primarily of interest-bearing bank accounts. The Company's cash positions represent assets held in checking and money market accounts. Cash and cash equivalents are generally available on a daily or weekly basis and are highly liquid in nature. Due to the balances being greater than $250,000, the Company does not have FDIC coverage on the entire amount of bank deposits. The Company believes this risk is minimal. In addition, the Company is subject to Security Investor Protection Corporation ("SIPC") protection on a vast majority of its financial assets.

Accounts Receivable

Accounts receivable are carried on a gross basis, with no discounting. The Company regularly reviews all aged accounts receivable for collectability and establishes an allowance as necessary for individual balances. Accounts receivable not expected to be collected within the next twelve months are included within Other Noncurrent Assets, Net on the balance sheets.

As of December 31, 2018 and 2017, the allowance for doubtful accounts was $5.2 million and $5.6 million, respectively. The amount charged to operations for doubtful accounts was zero, $0.7 million and $0.8 million for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018 and 2017, the amount charged against the allowance for doubtful accounts was $0.3 million and zero, respectively.

As of December 31, 2018 and 2017, the Company included accounts receivable of $5.1 million and $5.5 million, respectively, in Other Noncurrent Assets, Net due to their long-term nature.

Advances to Operators

The Company participates in the drilling of crude oil and natural gas wells with other working interest partners. Due to the capital intensive nature of crude oil and natural gas drilling activities, the working interest partner responsible for conducting the drilling operations may request advance payments from other working interest partners for their share of the costs. The Company expects such advances to be applied by working interest partners against joint interest billings for its share of drilling operations within 90 days from when the advance is paid.

Other Property and Equipment

Property and equipment that are not crude oil and natural gas properties are recorded at cost and depreciated using the straight-line method over their estimated useful lives of three to seven years. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred. Long-lived assets, other than crude oil and natural gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. The Company has not recognized any impairment losses on non-crude oil and natural gas long-lived assets. Depreciation expense was $0.1 million, $0.2 million, and $0.2 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Oil and Gas Properties

Northern follows the full cost method of accounting for crude oil and natural gas operations whereby all costs related to the exploration and development of crude oil and natural gas properties are capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisition, and exploration activities. Internal costs that are capitalized are directly attributable to acquisition, exploration and development activities and do not include costs related to production, general corporate overhead or similar activities. Costs associated with production and general corporate activities are expensed in the period incurred. Capitalized costs are summarized as follows for the years ended December 31, 2018, 2017 and 2016, respectively:

	December 31,					
	2018		**2017**		**2016**	
Capitalized Certain Payroll and Other Internal Costs	$	882,053	$	930,289	$	1,890,480
Capitalized Interest Costs	147,197		147,775		356,196	
Total	$	1,029,250	$	1,078,064	$	2,246,676

As of December 31, 2018, the Company held leasehold interests in the Williston Basin on acreage located in North Dakota and Montana targeting the Bakken and Three Forks formations.

Proceeds from property sales will generally be credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of the proved reserves related to a single full cost pool. In the years ended December 31, 2018, 2017 and 2016, there were no property sales that resulted in a significant alteration.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing twelve-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives designated as hedges for accounting purposes, if any, that hedge the Company’s oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or non-cash writedown is required.

The Company did not have any ceiling test impairment for the year ended December 31, 2018. Impairment charges affect the Company's reported net income but do not reduce the Company's cash flow.

The Company computes the provision for depletion of oil and natural gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unproved costs and related carrying costs are excluded from the depletion base until the properties associated with these costs are considered proved. The following table presents depletion and depletion per BOE sold of the Company's proved oil and natural gas properties for the periods presented:

	Year Ended December 31,					
	2018		2017		2016	
Depletion of Proved Oil and Natural Gas Properties	$	118,973,587	$	58,801,474	$	60,637,746
Depletion per BOE Sold	$	12.75	$	10.89	$	12.13

Capitalized costs associated with impaired unproved properties and capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs, are depleted and amortized on the unit-of-production method. Under this method, depletion is calculated at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the period. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion and full cost ceiling calculations. For the years ended December 31, 2018, 2017 and 2016, the Company expired leases of $9.4 million, $18.7 million, and $13.4 million, respectively.

At December 31, 2018, the Company performed an impairment review using prices that reflect an average of 2018's monthly prices as prescribed pursuant to the SEC's guidelines. If lower average monthly pricing is reflected in the trailing twelve-month average pricing calculation, the present value of the Company's future net revenues could decline and impairment could be recognized. SEC defined prices for each quarter-end in 2018 were as follows:

SEC Defined Prices for 12-Months Ended	NYMEX Oil Price (per Bbl)		Henry Hub Gas Price (per MMBtu)	
December 31, 2018	$	65.56	$	3.10
September 30, 2018	63.43		2.91	
June 30, 2018	57.67		2.92	
	53.49		3.00	

March 31,
2018

Asset Retirement Obligations

The Company accounts for its abandonment and restoration liabilities under Financial Accounting Standards Board (“FASB”) ASC Topic 410, “Asset Retirement and Environmental Obligations” (“FASB ASC 410”), which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset upon initial recognition. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Business Combinations

The Company accounts for its acquisitions that qualify as a business using the acquisition method under FASB ASC Topic 805, “Business Combinations.” Under the acquisition method, assets acquired and liabilities assumed are recognized and measured at their fair values. The use of fair value accounting requires the use of significant judgment since some transaction components do not have fair values that are readily determinable. The excess, if any, of the purchase price over the net fair value amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. Conversely, if the fair value of assets acquired exceeds the purchase price, including liabilities assumed, the excess is immediately recognized in earnings as a bargain purchase gain.

Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, receivables, payables, commodity derivative assets and liabilities, contingent consideration, debt exchange derivative liability, and long-term debt. The carrying amounts of cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the Company's derivative instruments assets and liabilities are based on a third-party industry-standard pricing model using contract terms and prices and assumptions and inputs that are substantially observable in active markets throughout the full term of the instruments, including forward oil price curves, discount rates, volatility factors and credit risk adjustments. The fair values of the Company's contingent consideration and debt exchange derivative liabilities are determined by a third-party valuation specialist using Monte Carlo simulations including significant inputs such as (i) the Company's common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) volatility of the Company's common stock, and (iv) expected average daily trading volumes.

The carrying amount of long-term debt associated with borrowings outstanding under the Company's revolving credit facility approximates fair value as borrowings bear interest at variable rates. The carrying amounts of the Company's second lien notes may not approximate fair value because carrying amounts are net of unamortized premiums and debt issuance costs, and the second lien notes bear interest at fixed rates. See Note 12 for additional discussion.

Debt Issuance Costs

Debt issuance costs include origination, legal and other fees to issue debt in connection with the Company's debt arrangements. These debt issuance costs are amortized over the term of the related financing using the straight-line method, which approximates the effective interest method (see Note 4). The amortization of debt issuance costs for the years ended December 31, 2018, 2017 and 2016 was $5.1 million, $4.1 million and $3.8 million, respectively.

During the year ended December 31, 2018, the Company wrote-off $17.7 million of debt issuance costs as a result of the early redemptions of its Term Loan Credit Agreement and its 8.000% Senior Notes Due 2020 (see Note 4). During the year ended December 31, 2017 , $0.1 million of debt issuance costs were written-off as a result of a reduction in the borrowing base of the Company's prior revolving credit facility, which was repaid using the proceeds from the term loan credit agreement entered into on November 1, 2017. As a result of the repayment of the Company's prior revolving credit facility, the Company also wrote-off debt issuance costs of $1.0 million during 2017.

Bond Premium/Discount on Long-term Debt

On October 5, 2018, the Company recorded a bond premium of $14.0 million in connection with the issuance of its Additional 2L Notes (see Note 4). This bond premium is being amortized over the term of the related financing using the straight-line method, which approximates the effective interest method. The amortization of the bond premium was $0.8 million for the year ended December 31, 2018.

On May 18, 2015, the Company recorded a bond discount of $10.0 million in connection with the "8.000% Senior Notes Due 2020" (see Note 4). This bond discount was being amortized over the term of the related financing using the straight-line method, which approximates the effective interest method. The amortization of the bond discount for the years ended December 31, 2018, 2017 and 2016 was $0.8 million, $2.0 million and $2.0 million, respectively. As a result of various exchange agreements and the early redemption of the 8.000% Senior Notes Due 2020, the Company wrote-off $4.0 million of bond discount during 2018.

On May 13, 2013, the Company recorded a bond premium of $10.5 million in connection with the “8.000% Senior Notes Due 2020” (see Note 4). This bond premium was being amortized over the term of the related financing using the straight-line method, which approximates the effective interest method. The amortization of the bond premium was $0.6 million, $1.5 million, and $1.5 million for the years ended December 31, 2018, 2017 and 2016, respectively. As a result of various exchange agreements and the early redemption of the 8.000% Senior Notes Due 2020, the Company wrote-off $3.0 million of bond premium during 2018.

Revenue Recognition

The Company adopted ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* and the series of related accounting standard updates that followed, on January 1, 2018 using the modified retrospective method of adoption. Adoption of the ASU did not require an adjustment to the opening balance of equity and did not change the Company's amount and timing of revenues.

The Company's revenues are primarily derived from its interests in the sale of oil and natural gas production. The Company recognizes revenue from its interests in the sales of oil and natural gas in the period that its performance obligations are satisfied. Performance obligations are satisfied when the customer obtains control of product, when the Company has no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sales of oil and natural gas are made under contracts which the third-party operators of the wells have negotiated with customers, which typically include variable consideration that is based on pricing tied to local indices and volumes delivered in the current month. The Company receives payment from the sale of oil and natural gas production from one to three months after delivery. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in trade receivables, net in the balance sheets. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received, however, differences have been and are insignificant. Accordingly, the variable consideration is not constrained.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption in accordance with ASC 606. The exemption, as described in ASC 606-10-50-14(a), applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company's oil is typically sold at delivery points under contracts terms that are common in our industry. The Company's natural gas produced is delivered by the well operators to various purchasers at agreed upon delivery points under a limited number of contract types that are also common in our industry. Regardless of the contract type, the terms of these contracts compensate the well operators for the value of the oil and natural gas at specified prices, and then the well operators will remit payment to the Company for its share in the value of the oil and natural gas sold.

A wellhead imbalance liability equal to the Company's share is recorded to the extent that the Company's well operators have sold volumes in excess of its share of remaining reserves in an underlying property. However, for the years ended December 31, 2018, 2017 and 2016, the Company's natural gas production was in balance, meaning its cumulative portion of natural gas production taken and sold from wells in which it has an interest equaled its entitled interest in natural gas production from those wells.

The Company's disaggregated revenue has two revenue sources which are oil sales and natural gas and NGL sales and only operates in one geographic area, the Williston Basin in North Dakota and Montana. Oil sales for the the years ended December 31, 2018, 2017 and 2016 were $450.1 million, $204.6 million and $152.3 million, respectively. Natural gas and NGL sales for the years ended December 31, 2018, 2017 and 2016 were $43.8 million, $19.4 million and $7.3 million, respectively.

Concentrations of Market and Credit Risk

The future results of the Company's crude oil and natural gas operations will be affected by the market prices of crude oil and natural gas. The availability of a ready market for crude oil and natural gas products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of crude oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of crude oil, natural gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company operates in the exploration, development and production sector of the crude oil and natural gas industry. The Company's receivables include amounts due, indirectly via the third-party operators of the wells, from purchasers of its crude oil and natural gas production. While certain of these customers, as well as third-party operators of the wells, are affected by periodic downturns in the economy in general or in their specific segment of the crude oil or natural gas industry, the Company believes that its level of credit-related losses due to such economic fluctuations have been immaterial.

The Company manages and controls market and counterparty credit risk. In the normal course of business, collateral is not required for financial instruments with credit risk. Financial instruments which potentially subject the Company to credit risk consist principally of temporary cash balances and derivative financial instruments. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments. The Company attempts to limit the amount of credit exposure to any one financial institution or company. The Company believes the credit quality of its counterparties is generally high. In the normal course of business, letters of credit or parent guarantees may be required for counterparties which management perceives to have a higher credit risk.

Stock-Based Compensation

The Company records expense associated with the fair value of stock-based compensation. For fully vested stock and restricted stock grants, the Company calculates the stock-based compensation expense based upon estimated fair value on the date of grant. In determining the fair value of performance-based share awards subject to market conditions, the Company utilizes a Monte Carlo simulation prepared by an independent third party. For stock options, the Company uses the Black-Scholes option valuation model to calculate stock-based compensation at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. Changes in these assumptions can materially affect the fair value estimate.

Treasury Stock

Treasury stock is recorded at cost, which includes incremental direct transaction costs, and is retired upon acquisition as a result of share repurchases under the share repurchase program or from the withholding of shares of stock to satisfy employee tax withholding obligations that arise upon the lapse of restrictions on their stock-based awards at the employees' election.

Stock Issuance

The Company records any stock-based compensation awards issued to non-employees and other external entities for goods and services at either the fair market value of the goods received or services rendered or the instruments issued in exchange for such services, whichever is more readily determinable.

Income Taxes

The Company’s income tax expense, deferred tax assets and deferred tax liabilities reflect management’s best assessment of estimated current and future taxes to be paid. The Company estimates for each interim reporting period the effective tax rate expected for the full fiscal year and uses that estimated rate in providing for income taxes on a current year-to-date basis. The Company’s only taxing jurisdiction is the United States (federal and state).

Deferred income taxes arise from temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements, which will result in taxable or deductible amounts in the future. In evaluating the Company’s ability to recover its deferred tax assets, the Company considers all available positive and negative evidence, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax-planning strategies, and results of recent operations. In projecting future taxable income, the Company begins with historical results and incorporates assumptions about the amount of future state and federal pretax operating income adjusted for items that do not have tax consequences. The assumptions about future taxable income require significant judgment and are consistent with the plans and estimates the Company is using to manage the underlying businesses.

Accounting standards require the consideration of a valuation allowance for deferred tax assets if it is “more likely than not” that some component or all of the benefits of deferred tax assets will not be realized. In assessing the need for a valuation allowance for the Company’s deferred tax assets, a significant item of negative evidence considered was the cumulative book loss over the three-year period ended December 31, 2018, driven primarily by the full cost ceiling impairments over that period. Additionally, the Company’s revenue, profitability and future growth are substantially dependent upon prevailing and future prices for oil and natural gas. The markets for these commodities continue to be volatile. Changes in oil and natural gas prices have a significant impact on the value of the Company’s reserves and on its cash flows. Due to these factors, management has placed a lower weight on the prospect of future earnings in its overall analysis of the valuation allowance.

In determining whether to establish a valuation allowance on the Company's deferred tax assets, management concluded that the objectively verifiable evidence of cumulative negative earnings for the three-year period ended December 31, 2018, is difficult to overcome with any forms of positive evidence that may exist. Accordingly, the valuation allowance against the Company's deferred tax asset at December 31, 2018 and 2017 was \$123.7 million and \$227.0 million respectively.

Net Income (Loss) Per Common Share

Basic earnings per share ("EPS") are computed by dividing net income (loss) (the numerator) by the weighted average number of common shares outstanding for the period (the denominator). Diluted EPS is computed by dividing net income (loss) by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period. Potential common shares include stock options and restricted stock. The number of potential common shares outstanding relating to stock options and restricted stock is computed using the treasury stock method.

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the years ended December 31, 2018, 2017 and 2016 are as follows:

	December 31,		
	2018	**2017**	**2016**
Weighted Average Common Shares Outstanding – Basic	236,206,467	61,408,855	61,173,547
Plus: Potentially Dilutive Common Shares Including Stock Options and Restricted Stock	567,454	—	—
Weighted Average Common Shares Outstanding – Diluted	236,773,921	61,408,855	61,173,547
Restricted Stock and Stock Options Excluded From EPS Due To The Anti-Dilutive Effect	50,685	1,109,511	829,313

As of December 31, 2018, 2017 and 2016, potentially dilutive shares from stock option awards were zero, 250,000 and 391,872, respectively. The Company also has potentially dilutive shares from restricted stock awards outstanding of 2,827,859, 1,721,533, and 1,905,104 at December 31, 2018, 2017 and 2016, respectively.

Derivative Instruments and Price Risk Management

The Company uses derivative instruments to manage market risks resulting from fluctuations in the prices of crude oil. The Company enters into derivative contracts, including price swaps, caps and floors, which require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of crude oil without the exchange of underlying volumes. The notional amounts of these financial instruments are based on expected production from existing wells. The Company may also use exchange traded futures contracts and option contracts to hedge the delivery price of crude oil at a future date.

The Company follows the provisions of FASB ASC 815, "Derivatives and Hedging" as amended. It requires that all derivative instruments be recognized as assets or liabilities on the balance sheet, measured at fair value and marked-to-market at the end of each period. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net on the statements of operations. See Note 13 for a description of the derivative contracts into which the Company has entered.

Impairment

Long-lived assets to be held and used are required to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Proved oil and natural gas properties accounted for using the full cost method of accounting are excluded from this requirement but continue to be subject to the full cost method's impairment rules. There was no impairment of other long-lived assets recorded for the years ended December 31, 2018, 2017 and 2016.

Supplemental Cash Flow Information

The following reflects the Company's supplemental cash flow information for the years ended December 31, 2018, 2017 and 2016 :

	December 31, 2018	2017	2016
Supplemental Cash Items:			
Cash Paid During the Period for Interest	$ 78,864,880	$ 65,565,698	$ 50,713,195
Cash Paid During the Period for Income Taxes	—	—	—
Non-cash Investing Activities:			
Oil and Natural Gas Properties Included in Accounts Payable	129,451,821	85,002,458	59,520,415
Capitalized Asset Retirement Obligations	2,854,141	1,187,791	1,353,307
Change in Prepaid Expenses and Other (1)	29,424,251	—	—
Contingent Consideration	32,312,140	—	—
Compensation Capitalized on Oil and Gas Properties	368,843	274,653	971,313
Issuance of Common Stock - Acquisitions of Oil and Natural Gas Properties	326,353,472	—	—
Non-cash Financing			

Activities:			
Exchange transactions - non-cash securities issued:			
Issuance of 8.50% Second Lien Notes due 2023	344,279,000	—	—
Issuance of Common Stock - fair value at issuance date	326,783,303	—	—
Debt Exchange Derivative Liability - fair value at issuance date	19,354,182	—	—
Exchange Transactions - non-cash securities exchanged:			
8.00% Unsecured Senior Notes due 2020 - carrying value	(590,041,303)	—	—

(1) The amount represents estimated post-closing working capital adjustments related to acquisitions of oil and natural gas properties. See Note 3 for further discussion.

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New Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the FASB that are adopted by the Company as of the specified effective date. If not discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on the Company's financial statements upon adoption.

In May 2014, the FASB issued a comprehensive new revenue recognition standard that supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition,* and industry-specific guidance in Subtopic 932-605, *Extractive Activities-Oil and Gas-Revenue Recognition*. The core principle of the new guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for transferring those goods or services. The new standard also requires significantly expanded disclosure regarding the qualitative and quantitative information of an entity's nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The standard creates a five-step model that requires companies to exercise judgment when considering the terms of a contract and all relevant facts and circumstances. The standard allows for several transition methods: (a) a full retrospective adoption in which the standard is applied to all of the periods presented, or (b) a modified retrospective adoption in which the standard is applied only to the most current period presented in the financial statements, including additional disclosures of the standard's application impact to individual financial statement line items. In March, April, May and December 2016, the FASB issued new guidance in Topic 606, *Revenue from Contracts with Customers,* to address the following potential implementation issues of the new revenue standard: (a) to clarify the implementation guidance on principal versus agent considerations, (b) to clarify the identification of performance obligations and the licensing implementation guidance and (c) to address certain issues in the guidance on assessing collectability, presentation of sales taxes, noncash consideration, and completed contracts and contract modifications at transition. This standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The Company previously followed the sales method of accounting for oil and natural gas production, which is generally consistent with the revenue recognition provision of the new standard. The majority of the Company's revenue arrangements generally consist of a single performance obligation to transfer promised goods or services. Based on the Company's evaluation process and review of its arrangements with operators who act as an intermediary and enter into contracts with purchasers who are the ultimate customers, the timing and amount of revenue recognized based on the standard is consistent with the Company's revenue recognition policy under previous guidance. The Company adopted the new standard effective January 1, 2018, using the modified retrospective approach, and has expanded its financial statement disclosures in order to comply with the standard. The Company has processes and controls to ensure it recognizes revenue in accordance with the appropriate accounting treatment and to generate the disclosures required under the new standard in the first quarter of 2018. The Company has determined the adoption of the standard did not have a material impact on its results of operations, cash flows, or financial position.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"). The standard requires lessees to recognize the assets and liabilities that arise from leases on the balance sheet. A lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The scope of ASU 2016-02 does not apply to leases used in the exploration or use of minerals, oil, natural gas, or other similar non-regenerative resources. The new guidance is effective for annual and interim reporting periods beginning after December 15, 2018. The Company is leveraging external consultants to evaluate the impacts of ASU 2016-02. Further, the Company is also evaluating policies, internal controls, and processes that will be necessary to support the additional accounting and disclosure requirements. The Company plans to make certain policy elections allowed under ASU 2016-02 including (a) not recognizing lease assets or liabilities when lease terms are less than twelve months, (b) for agreements that contain both lease and non-lease components, combining these components together and accounting for them as a single lease, (c) not reassessing contracts, including land easements, that commenced prior to adoption. In July 2018, the FASB issued ASU No. 2018-11, Leases (Topic 842): Targeted Improvements ("ASU 2018-11"). ASU 2018-11 provides an additional transition method for adopting ASU 2016-02. The Company anticipates making a policy election in connection with adopting ASU 2018-11, which will eliminate the need for adjusting prior period comparable financial statements prepared under current lease accounting guidance. The Company will adopt ASU 2016-02 and ASU 2018-11 on January 1, 2019, using the modified retrospective approach.

In preparation for adoption, we have substantially completed a process to identify a complete population of our leases, including the review of various contracts to identify whether such arrangements convey the right to control the use of an identified asset. Based on our portfolio of leases as of December 31, 2018, we estimate the impact of the adoption will not be material to the Company's balance sheets, the results of operations, equity or cash flows. We have additionally begun implementing new business processes and developing new controls and the expanded disclosures of our leasing arrangements.

In August 2016, the FASB issued ASU No. 2016-15, Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments. This guidance provides guidance on eight specific cash flow issues. This amendment is effective for periods beginning after December 15, 2017, with early adoption permitted. The Company adopted this standard on January 1, 2018 and it did not result in a material impact on its financial statements and related disclosures.

In January 2017, the FASB issued new guidance in ASC 805, Business Combinations, to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The amendments in this ASU provide a screen to determine when a set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. If the screen is not met, the amendments in this ASU require that to be considered a business, a set must include, at a minimum, an input and a substantive process that, together, significantly contribute to the ability to create an output.

The primary effect of adoption of this ASU is that, depending on the facts and circumstances of each transaction, more transactions could be accounted for as acquisitions of assets. The Company adopted this ASU on January 1, 2018 on a prospective basis, and the adoption did not have an effect on its financial statements. See Note 3 for discussion of the Company's 2018 acquisitions of oil and natural gas properties, which were accounted for as business combinations under this ASU.

In May 2018, the FASB issued ASU 2018-07, Compensation - Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting, which simplifies the accounting for share-based payments granted to nonemployees for goods and services. This guidance will better align the treatment of share-based payments to nonemployees with the requirements for such share-based payments granted to employees. This guidance is effective for all public entities for fiscal years beginning after December 15, 2018, including interim periods within that year. The Company is currently in the process of evaluating this new standard update but does not expect it will have a material impact on the financial statements.

In August 2018, the FASB issued new guidance in ASC 820, Fair Value Measurement, to modify disclosure requirements. The amendments in this ASU remove, modify, and add certain disclosure requirements as a part of the disclosure framework project, which primarily focus on improving the effectiveness of disclosures in the notes to the financial statements. The guidance is effective for annual periods beginning after December 31, 2019, and interim periods within those annual periods. The Company is currently assessing the impact of the guidance, however it does not expect any impact of this new guidance on its financial statements to be material.

NOTE 3 CRUDE OIL AND NATURAL GAS PROPERTIES

The value of the Company’s crude oil and natural gas properties consists of all acquisition costs (including cash expenditures and the value of stock consideration), drilling costs and other associated capitalized costs. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in the accompanying statements of operations from the closing date of the acquisition. Acquired assets and liabilities assumed are recorded based on their estimated fair value at the time of the acquisition. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities. Development capital expenditures and purchases of properties that were in accounts payable and not yet paid in cash at December 31, 2018 and 2017 were approximately $129.5 million and $85.0 million, respectively.

2018 Acquisitions

During 2018, excluding the W Energy, Pivotal and Salt Creek acquisitions described in more detail below, the Company acquired leasehold interests covering approximately 10,932 net acres.

W Energy Acquisition

On July 27, 2018, the Company entered into a purchase and sale agreement, which was subsequently amended on September 25, 2018 (as amended, the “W Energy Purchase Agreement”), with WR Operating LLC (“W Energy”), to acquire, effective as of July 1, 2018, approximately 27.2 net producing wells and 5.9 net wells in progress, as well as approximately 10,633 net acres in North Dakota (the “W Energy Acquisition”). On October 1, 2018, the Company closed on the acquisition for total estimated consideration of $341.6 million, consisting of (i) $97.8 million in cash (which reflects the $117.1 million unadjusted cash consideration under the W Energy Purchase Agreement, less $2.2 million of working capital adjustments made at closing and $17.0 million of additional estimated post-closing working capital adjustments), (ii) 51,476,961 shares of Company common stock valued at $220.8 million, based on the $4.29 per share closing price of Company common stock on the closing date of the acquisition, and (iii) $23.0 million in value attributable to potential additional contingent consideration in the future (described in more detail below). The results of operations from the October 1, 2018 closing date through December 31, 2018, represented approximately $29.9 million of revenue and $5.8 million of direct operating expenses. No material transaction costs were incurred in connection with this acquisition. The following table reflects a preliminary estimate of the fair values of the net assets and liabilities as of the date of acquisition, which are subject to customary post-closing adjustments:

	(in thousands)	
Fair value of net assets:		
Proved oil and natural gas properties	$	341,633
Asset retirement cost	939	
Total assets acquired	342,572	
Asset retirement obligations	(939)	
Net assets acquired	$	341,633
Fair value of consideration paid for net assets:		
Cash consideration	$	97,838
Issuance of common stock (51.5 million shares at $4.29 per share)	220,836	
Contingent consideration	22,959	
Total fair value of consideration transferred	$	341,633

A contingent consideration liability arising from potential additional consideration in connection with the W Energy Acquisition has been recognized at its fair value. The amount of additional contingent consideration payable by the Company, if any, is dependent upon the performance of the Company's share price over a thirteen month period ending in October 2019. The acquisition date fair value of the potential additional consideration, totaling $23.0 million, was recorded within contingent consideration liabilities on the Company's balance sheets. Changes in the fair value of the liability (that were not accounted for as revisions of the acquisition date fair value) are recorded in other income (expense) on the Company's statement of operations.

Pivotal Acquisition

On July 17, 2018, the Company entered into purchase and sale agreements with Pivotal Williston Basin, LP and Pivotal Williston Basin LP, II, to acquire approximately 20.8 net producing wells and 2.2 net wells in process, as well as approximately 444 net acres in North Dakota (the "Pivotal Acquisition"). The acquisition expanded the Company's footprint in the core of the Williston Basin. On September 17, 2018, the Company closed on the acquisition for total estimated consideration of $146.1 million, consisting of (i) $48.2 million in cash (which reflects the $68.4 million million aggregate unadjusted cash consideration provided for in the purchase agreements, less $7.8 million of working capital adjustments made at closing and $12.4 million of additional estimated post-closing working capital adjustments), (ii) 25,753,578 shares of the Company's common stock valued at $88.6 million, based on the $3.44 per share closing price of the Company's common stock on the closing date of the acquisition, and (iii) $9.4 million in value attributable to potential additional contingent consideration (described in more detail below). The results of operations from the September 17, 2018 closing date through December 31, 2018, represented approximately $17.9 million of revenue and $3.0 million of direct operating expenses. No material transaction costs were incurred in connection with this acquisition. The following table reflects a preliminary estimate of the fair values of the net assets and liabilities as of the date of acquisition, which are subject to customary post-closing adjustments:

	(in thousands)	
Fair value of net assets:		
Proved oil and natural gas properties	$	146,134
Asset retirement cost	$	644
Total assets acquired	$	146,778
Asset retirement obligations	$	(644)
Net assets acquired	$	146,134
Fair value of consideration paid for net assets:		
Cash consideration	$	48,189
Issuance of common stock (25.8 million shares at $3.44 per share)	$	88,592
Contingent consideration	$	9,353
Total fair value of consideration transferred	$	146,134

A contingent consideration liability arising from potential additional consideration in connection with the Pivotal Acquisition has been recognized at its fair value. The amount of additional contingent consideration payable by the Company, if any, is dependent upon the performance of the Company's share price over a thirteen month period ending in October 2019. The acquisition date fair value of the potential additional consideration, tot g $9.4 million, was recorded within contingent consideration liabilities on the Company's balance sheets. Changes in the fair value of the liability (that were not accounted for as revisions of the acquisition date fair value) are recorded in other income (expense) on the Company's statement of operations.

The following summarized unaudited pro forma condensed statements of operations information for the years ended December 31, 2018 and 2017 assumes that both the W Energy Acquisition and Pivotal Acquisition occurred as of January 1, 2017. The Company prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma information may not be indicative of the results that would have occurred had the Company completed both of these acquisitions as of January 1, 2017, or that would be attained in the future.

(in thousands)	Year Ended December 31, 2018		2017	
Revenues	$	797,847	$	294,862
Net Income	$	174,070	$	283

Salt Creek Acquisition

On April 25, 2018, the Company entered into a purchase and sale agreement with Salt Creek Oil and Gas, LLC, to acquire 64 gross, 5.5 net producing (PDP) wells, 31 gross, 1.5 net drilling and completing (PDNP) wells and 1,319 net acres located in McKenzie and Mountrail counties of North Dakota in the Company's core development area. The acquisition expanded the Company's footprint in the core of the Williston Basin. On June 4, 2018, the Company closed the transaction for consideration of $60.0 million which is comprised of $44.7 million of cash consideration and $15.2 million of common stock consideration. The results of operations from the June 4, 2018 closing date through December 31, 2018, represented approximately $11.6 million of revenue and $2.5 million of direct operating expenses. No material transaction costs were incurred in connection with this acquisition. The following table reflects a preliminary estimate of the fair values of the net assets and liabilities as of the date of acquisition, which are subject to customary post-closing adjustments:

	(in thousands)	
Fair value of net assets:		
Proved oil and natural gas properties	$	59,978
Asset retirement cost	$	154
Total assets acquired	$	60,132
Asset retirement obligations	$	(154)
Net assets acquired	$	59,978
Fair value of consideration paid for net assets:		
Cash consideration	$	44,738
Issuance of common stock (6.0 million shares at $2.54 per share)	$	15,240
Total fair value of consideration transferred	$	59,978

2017 Acquisitions

During 2017, the Company acquired leasehold interests covering approximately 1,934 net acres.

2016 Acquisitions

During 2016, the Company acquired leasehold interests covering approximately 3,399 net acres.

On October 6, 2016, the Company entered into a definitive purchase and sale agreement with a third party, for their interests in 144 gross (3.8 net) producing oil and gas wells and associated acreage. On October 26, 2016, the Company closed the transaction for cash consideration of $9.4 million which is comprised of $8.9 million related to producing properties and a $0.5 million reimbursement of drilling costs on in process wells. The results of operations from the October 26, 2016 closing date through December 31, 2016, represented approximately $1.2 million of revenue and $0.5 million of direct operating expenses. The combined pro forma information has not been presented due to its immateriality. No material transaction costs were incurred in connection with this purchase and there was no goodwill recorded from this acquisition.

Divestitures

From time-to-time the Company may divest assets. In addition, the Company may trade leasehold interests with operators to balance working interests in spacing units to facilitate and encourage a more expedited development of the Company's acreage.

Unproved Properties

Unproved properties not being amortized comprise approximately 11,054 net acres and 14,377 net acres of undeveloped leasehold interests at December 31, 2018 and 2017, respectively. The Company believes that the majority of its unproved costs will become subject to depletion within the next five years by proving up reserves relating to the acreage through exploration and development activities, by impairing the acreage that will expire before the Company can explore or develop it further or by determining that further exploration and development activity will not occur. The timing by which all other properties will become subject to depletion will be dependent upon the timing of future drilling activities and delineation of its reserves.

Excluded costs for unproved properties are accumulated by year. Costs are reflected in the full cost pool as the drilling costs are incurred or as costs are evaluated and deemed impaired. The Company anticipates these excluded costs will be included in the depletion computation over the next five years. The Company is unable to predict the future impact on depletion rates. The following is a summary of capitalized costs excluded from depletion at December 31, 2018 by year incurred.

	December 31,			
	2018	**2017**	**2016**	**Prior Years**
Property Acquisition	$ 3,298,259	$ 70,855	$ 762	$ 936,637
Development	—	—	—	—
Total	$ 3,298,259	$ 70,855	$ 762	$ 936,637

All properties that are not classified as proved properties are considered unproved properties and, thus, the costs associated with such properties are not subject to depletion. Once a property is classified as proved, all associated acreage and drilling costs are subject to depletion.

The Company historically has acquired unproved properties by purchasing individual or small groups of leases directly from mineral owners, landmen or lease brokers, which leases historically have not been subject to specified drilling projects, and by purchasing lease packages in identified project areas controlled by specific operators. The Company generally participates in drilling activities on a heads up basis by electing whether to participate in each well on a well-by-well basis at the time wells are proposed for drilling.

The Company assesses all items classified as unproved property on an annual basis, or if certain circumstances exist, more frequently, for possible impairment or reduction in value. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and amortization. For the years ended December 31, 2018, 2017 and 2016, the Company included $0.3 million, $0.6 million and $7.0 million, respectively, related to expiring leases within costs subject to the depletion calculation. These amounts represent lease expiration costs that were not previously included within costs subject to the depletion calculation during a prior year.

NOTE 4 LONG-TERM DEBT

The Company’s long-term debt consists of the following:

	December 31, 2018			
	Principal Balance	**Unamortized Net Premium**	**Debt Issuance Costs, Net**	**Long-term Debt, Net**
Second Lien Notes due 2023	$ 695,139,698	$ 13,236,967	$ (18,173,393)	$ 690,203,272
Revolving Credit Facility [(1)]	140,000,000	—	—	140,000,000
Total	$ 835,139,698	$ 13,236,967	$ (18,173,393)	$ 830,203,272

	December 31, 2017			
	Principal Balance	**Unamortized Net Discount**	**Debt Issuance Costs, Net**	**Long-term Debt, Net**
Unsecured Notes due 2020	$ 700,000,000	$ (1,197,954)	$ (6,847,557)	$ 691,954,489
Term Loan Credit Agreement	300,000,000	—	(12,630,267)	$ 287,369,733
Total	$ 1,000,000,000	$ (1,197,954)	$ (19,477,824)	$ 979,324,222

(1) Debt issuance costs related to the Company's revolving credit facility are recorded in “Other Noncurrent Assets, Net” on the balance sheets.

Overview of 2018 Refinancing Transactions

During 2018, the Company completed various refinancing transactions related to its debt arrangements, which are summarized as follows (with additional detail included below):

- On May 15, 2018, closed an exchange transaction whereby the Company issued $344.3 million of Second Lien Notes (defined below) and 103.2 million shares common stock in exchange for the redemption of $496.7 million of Unsecured Notes (defined below).
- During the second and third quarters of 2018, closed additional exchange transactions whereby, in total, the Company issued 32.8 million shares of common stock in exchange for the redemption of $100.5 million of Unsecured Notes.
- On October 5, 2018, entered into a new $750.0 million Revolving Credit Facility (defined below).
- On October 5, 2018, issued an additional $350.0 million aggregate principal amount of Second Lien Notes.
- On October 5, 2018, repaid all $360.0 million in loans under, and retired in full, the Term Loan Credit Agreement (defined below).
- On October 11, 2018, redeemed and repaid in full all remaining outstanding Unsecured Notes, which consisted of $102.8 million in principal amount.

May 15, 2018 Exchange Transaction

On January 31, 2018 (the “Exchange Agreement Date”), Northern entered into an exchange agreement that was subsequently amended (as amended, the “Exchange Agreement”) with holders (the “Supporting Noteholders”) of approximately $496.7 million, or 71%, of the aggregate principal amount of the Company’s outstanding 8.000% senior unsecured notes due 2020 (the “Unsecured Notes”), pursuant to which the Supporting Noteholders agreed to exchange all of the Unsecured Notes held by each such Supporting Noteholder for approximately $155.0 million of the Company’s common stock and approximately $344.3 million in aggregate principal amount of new 8.500% senior secured second lien notes due 2023 (the “Second Lien Notes”) (such exchange, the “Exchange Transaction”).

On May 15, 2018 (the “Exchange Closing Date”), pursuant to the Exchange Agreement, the Company completed the Exchange Transaction and issued 103,249,915 shares of common stock and $344.3 million of Second Lien Notes in exchange for the Unsecured Notes held by the Supporting Noteholders. Separately, but in connection with the Exchange Transaction, the Company and certain investors had previously entered into subscription agreements (the “Subscription Agreements”) whereby such investors agreed to purchase up to $52.0 million of common stock at $1.50 per share. Pursuant to the Subscription Agreements, on the Exchange Closing Date, the Company issued 34,666,668 shares of common stock to such investors.

As a result of the closing of the Exchange Agreement, the Company recorded an $82.0 million loss on the extinguishment of debt for the year ended December 31, 2018.

Additional Exchange Transactions

During the second and third quarters of 2018, the Company entered into and closed ten additional independent, separately negotiated exchange agreements with holders of the Company’s Unsecured Notes (the “Additional Exchanges”). Pursuant to each such exchange agreement, the Company agreed to issue the holder shares of its common stock in exchange for certain Unsecured Notes held by such holder. In total, during 2018, the Company issued 32.8 million shares of common stock in exchange for $100.5 million in principal amount of the Unsecured Notes pursuant to the Additional Exchanges.

Pursuant to the exchange agreements governing the Additional Exchanges, with limited exceptions, the Company subjected the holders to a restricted sale period on the shares of common stock issued to them. These restricted sale periods are of varying lengths and subject to varying exceptions. Generally, if at the end of the applicable restricted sale period the Company’s common stock trades below specified levels, the Company may be required to pay the applicable holder additional consideration either in the form of cash or additional shares of common stock. The value of this liability is carried on the Company’s balance sheet as the debt exchange derivative liability, the value of which is based on Monte Carlo simulations which considered various inputs including (i) the Company’s common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) volatility of the Company’s common stock, and (iv) expected average daily trading volumes. As of December 31, 2018, the Company’s debt exchange derivative liability related to the Additional Exchanges was $18.2 million.

As a result of the Additional Exchanges, the Company recorded a loss on the extinguishment of debt of $18.4 million for the year ended December 31, 2018.

Revolving Credit Facility

On October 5, 2018, the Company entered into a new $750.0 million revolving credit facility (the “Revolving Credit Facility”) with Royal Bank of Canada, as administrative agent, and the lenders from time to time party thereto. The revolving credit agreement will mature five years from the closing date, provided that the maturity date shall be 91 days prior to the scheduled maturity date of the Second Lien Notes.

The revolving credit agreement is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to the Company and its subsidiaries’ (if any) oil and gas properties. The initial borrowing base is $425.0 million until the next scheduled redetermination. The borrowing base will be redetermined semiannually on or around April 1st and October 1st, with one interim “wildcard” redetermination available between scheduled redeterminations. The April 1st scheduled redetermination shall be based on a January 1st engineering report audited by a 3rd party (reasonably acceptable by the Agent).

At the Company’s option, borrowings under the revolving credit agreement shall bear interest at the base rate or LIBOR plus an applicable margin. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank’s prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from 75 to 175 basis points, and the applicable margin for LIBOR loans ranges from 175 to 275 basis points, in each case depending on the percentage of the borrowing base utilized.

The revolving credit agreement contains negative covenants that limit the Company’s ability, among other things, to pay dividends, incur additional indebtedness, sell assets, enter into certain derivatives contracts, change the nature of its business or operations, merge, consolidate, or make certain types of investments. In addition, the revolving credit agreement requires that the Company comply with the following financial covenants: (i) as of the date of determination, the ratio of total net debt to EBITDAX (as defined in the revolving credit agreement) shall be no more than 4.00 to 1.00, measured on a pro forma rolling four quarter basis, and (ii) the current ratio (defined as consolidated current assets including unused amounts of the total commitments, but excluding non-cash assets under FASB ASC 815, divided by consolidated current liabilities excluding current non-cash obligations under FASB ASC 815 and current maturities under the revolving credit agreement and the Second Lien Notes (as defined in the revolving credit agreement)) shall not be less than 1.00.

The Company's obligations under the revolving credit agreement may be accelerated, subject to customary grace and cure periods, upon the occurrence of certain Events of Default (as defined in the revolving credit agreement). Such Events of Default include customary events for a financing agreement of this type, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of affirmative or negative covenants, defaults on other indebtedness of us or the Company’s subsidiaries, defaults related to judgments and the occurrence of a Change in Control (as defined in the revolving credit agreement).

The Company’s obligations under the Revolving Credit Facility are secured by mortgages on not less than 85.0% of the value of proven reserves associated with the oil and gas properties included in the determination of the borrowing base. Additionally, the Company entered into a Guaranty and Collateral Agreement in favor of the Agent for the secured parties, pursuant to which the Company’s obligations under the revolving credit agreement are secured by a first priority security interest in substantially all of the Company’s assets.

Second Lien Notes due 2023

On May 15, 2018, the Company issued Second Lien Notes with an aggregate principal amount of $344.3 million (the “Original 2L Notes”) in connection with the closing of the Exchange Agreement described above. On October 5, 2018, the Company issued an additional $350.0 million aggregate principal amount of Second Lien Notes (the “Additional 2L Notes”), the proceeds of which were used in connection with the retirement of the Company's Term Loan Credit Agreement. In addition, during 2018, the Company issued $0.9 million aggregate principal amount of Second Lien Notes pursuant to the interest payment-in-kind provisions thereof (the “2L PIK Notes” and, together with the Original 2L Notes and the Additional 2L Notes, the “Second Lien Notes”).

The terms of the Second Lien Notes include those stated in the Indenture entered into on May 15, 2018 by the Company and Wilmington Trust, National Association, as trustee (the “Original 2L Indenture”), as amended by the First Supplemental Indenture, dated September 18, 2018 (the “First Supplemental 2L Indenture”), and the Second Supplemental Indenture, dated October 5, 2018 (the “Second Supplemental 2L Indenture” and, together with the Original 2L Indenture and the First Supplemental 2L Indenture, the “2L Indenture”).

The Second Lien Notes are the senior secured obligations of the Company and rank equal in right of payment to all existing and future senior indebtedness of the Company and its subsidiaries. The Second Lien Notes are secured by second priority security interests in substantially all assets of the Company, subject to certain exceptions. The Second Lien Notes will be guaranteed by all of the Company’s direct and indirect subsidiaries that guarantee indebtedness under any other indebtedness for borrowed money of the Company or any of the Company’s subsidiary guarantors. As of December 31, 2018, the Company does not have any subsidiaries. The Second Lien Notes will mature on May 15, 2023.

Interest on the Second Lien Notes will accrue at a rate of 8.500% per annum payable in cash quarterly in arrears on the first day of each calendar quarter. Beginning on July 1, 2018, the interest rate will be increased by 1.000% per annum, which increase shall be payable in kind (the “PIK Component”). Commencing June 30, 2018, and as of each December 31st and June 30th thereafter, if the Company’s total debt to EBITDAX ratio is (i) less than 3.00 to 1.00 as of such date, the PIK Component shall cease accruing effective as of the next interest payment date, or (ii) greater than or equal to 3.00 to 1.00 as of such date or if the Company fails to deliver financial statements, the PIK Component shall continue to accrue (or, if then not accruing, automatically commence accruing as of the next interest payment date) and be payable quarterly. The PIK Component began accruing on June 30, 2018. Additionally, if the Company incurs junior lien or unsecured debt with a cash interest rate in excess of 9.500%, the cash rate on the Second Lien Notes will be increased by such excess. Default interest will be payable in cash on demand at the then applicable interest rate plus 3.000% per annum.

The Company may redeem all or a portion of any of the Second Lien Notes at the following redemption prices during the following time periods (plus accrued and unpaid interest on the Second Lien Notes redeemed): (i) from and after May 15, 2018 until May 15, 2021, 104%, (ii) on and after May 15, 2021 until May 15, 2022, 102%, and (iii) on and after May 15, 2022, 100%; provided that any redemption of Second Lien Notes (or the acceleration of Second Lien Notes) prior to May 15, 2020 shall also be accompanied by a make whole premium. Subject to the terms of an intercreditor agreement, the Company is also required to offer to prepay the Second Lien Notes with 100% of the net cash proceeds of asset sales, casualty events and condemnations in excess of $20.0 million, subject to customary exclusions and reinvestment provisions. Mandatory prepayment offers will be subject to payment of the make whole premium and redemption price set forth above, as applicable.

If a change of control occurs, the Company will be required to offer to repurchase the Second Lien Notes at the repurchase price of 101% of the principal amount of repurchased Second Lien Notes (subject to the prepayment provisions of the term loan credit agreement). The Second Lien Notes contain negative covenants that limit the Company’s ability, among other things, to pay cash dividends, incur additional indebtedness, sell assets, enter into certain derivatives contracts, change the nature of its business or operations, merge, consolidate, make certain types of investments, amend other debt documents, and incur any additional debt on a subordinated or junior basis to the term loan credit agreement and on a senior basis to the Second Lien Notes. The Second Lien Notes do not include any financial maintenance covenants.

The obligations of the Company under the Second Lien Notes may be accelerated upon the occurrence of an Event of Default (as such term is defined in the 2L Indenture). Events of Default include customary events for a capital markets debt financing of this type, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of affirmative or negative covenants, defaults on other indebtedness of the Company or its subsidiaries, bankruptcy or related defaults, defaults related to judgments and the occurrence of a Change of Control (as such term is defined in the 2L Indenture).

Term Loan Credit Agreement

The Company's term loan credit agreement was retired and repaid in full in connection with refinancing transactions that closed on October 5, 2018. The description of the term loan credit agreement that follows is as it existed immediately prior to its retirement. As a result of the early redemption of the term loan credit agreement, the total repayment was $420.1 million, which was comprised of $360.0 million in principal payments and $60.1 million pursuant to the term loan credit agreement's make whole and call premium provisions. As a result of this repayment, the Company recorded a loss on the extinguishment of debt of $72.2 million for the year ended December 31, 2018.

On November 1, 2017 (the “Effective Date”), the Company entered into a term loan credit agreement with TPG Specialty Lending, Inc., as administrative agent and collateral agent (in such capacities, the “Agent”), and the lenders from time to time party thereto. The term loan credit agreement, as amended, provides for the issuance of an aggregate principal amount of up to $500.0 million in term loans to the Company, consisting of (i) $300.0 million in initial term loans that were made on the Effective Date (the “Initial Loans”), (ii) $100.0 million in delayed draw term loans available to the Company, subject to satisfaction of certain conditions precedent described therein, for a period of 18-months after the Effective Date (the “Delayed Draw Loans”), and (iii) up to $100.0 million in incremental term loans on an uncommitted basis and subject, among other things, to one or more lenders agreeing in the future to make such loans (the “Incremental Loans”) (the Initial Loans, Delayed Draw Loans and the Incremental Loans, collectively, the “Loans”). Amounts borrowed and repaid under the term loan credit agreement could not be reborrowed. All borrowings under the term loan credit agreement were scheduled to mature on November 1, 2022. In addition to the $300.0 million in Initial Loans, the Company borrowed $60.0 million of Delayed Draw Loans on May 15, 2018.

Borrowings under the term loan credit agreement were subject to interest at a rate per annum equal to the “Adjusted LIBO Rate” (subject to a 1.00% floor) plus a 7.75% per annum margin. The “Adjusted LIBO Rate” was equal to the product of: (i) three-month LIBOR multiplied by (ii) the statutory reserve rate. Upon the occurrence and continuance of an event of default all outstanding Loans would bear interest at a rate equal to 3.00% per annum plus the then-effective rate of interest. Interest was payable on the last business day of each March, June, September and December.

A commitment fee was paid on the unused amount of the delayed draw commitments based on an annual rate of 2.00% (the “Commitment Fee”). Prepayments (including mandatory prepayments), terminations, refinancing, reductions and accelerations under the term loan credit agreement are subject to the payment of a yield maintenance amount for any such prepayment, termination, refinancing, reduction or acceleration occurring prior to May 15, 2020 (or, with respect to any Delayed Draw Loan, prior to the two-year anniversary of the funding of such Delayed Draw Loan) that allows the lenders to attain approximately the same yield as if such Loan remained outstanding for the entire two-year period, as applicable, plus a call protection amount equal to the product of the principal amount of Loans so prepaid, terminated, refinanced, reduced or accelerated multiplied by (i) 4.00% for any such prepayment, termination, refinancing, reduction or acceleration occurring, (A) with respect to the Initial Loans, on or prior to May 15, 2021, or (B) with respect to Delayed Draw Loans, on or prior to the 36-month anniversary of the funding of such Delayed Draw Loan, or (ii) 2.00% for any such prepayment, termination, refinancing, reduction or acceleration occurring, (A) with respect to the Initial Loans, after May 15, 2021 and on or prior to May 15, 2022, or (B) with respect to Delayed Draw Loans, after the 36-month anniversary but on or prior to the 48-month anniversary of the funding of such Delayed Draw Loan, in each case, as set forth in the term loan credit agreement. Additionally, to the extent that the

Loans are refinanced in full or the delayed draw commitments are terminated or reduced prior to the date that is 18 months after the Effective Date, the Company will be required to pay a yield maintenance amount in respect of the Commitment Fee that would have accrued on the delayed draw commitments as set forth in the term loan credit agreement.

The Company’s obligations under the term loan credit agreement were secured by mortgages on substantially all of the oil and gas properties of the Company subject to the limitations set forth in the term loan credit agreement. In connection with the term loan credit agreement, the Company entered into a guaranty and collateral agreement in favor of the Agent for the secured parties, pursuant to which the obligations of the Company under the term loan credit agreement and any swap agreements entered into with swap counterparties were secured by a first-priority security interest in substantially all of the assets of the Company.

Unsecured Notes due 2020

The Company's 8.000% senior unsecured notes due June 1, 2020 (the "Unsecured Notes") were subject to various exchange transactions during 2018 (described above). All remaining outstanding Unsecured Notes were redeemed and repaid in full on October 11, 2018. In connection with this final redemption, the Company recorded a loss on the extinguishment of debt of $0.8 million for the year ended December 31, 2018. The description of the Unsecured Notes that follows is as of immediately prior to such final redemption.

On May 18, 2012, the Company issued at par value $300 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "Original Notes"). On May 13, 2013, the Company issued at a price of 105.25% of par an additional $200 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "2013 Follow-on Notes"). On May 18, 2015, the Company issued at a price of 95.000% of par an additional $200 million aggregate principal amount of 8.000% senior unsecured notes due June 1, 2020 (the "2015 Mirror Notes" and, together with the Original Notes and the 2013 Follow-on Notes, the "Notes"). Interest is payable on the Notes semi-annually in arrears on each of June 1 and December 1. The Company currently does not have any subsidiaries and, as a result, the Notes are not currently guaranteed. Any subsidiaries the Company forms in the future may be required to unconditionally guarantee, jointly and severally, payment obligation under the Notes on a senior unsecured basis. The issuance of the Original Notes resulted in net proceeds to the Company of approximately $291.2 million, the issuance of the 2013 Follow-on Notes resulted in net proceeds to the Company of approximately $200.1 million, and the issuance of the 2015 Mirror Notes resulted in net proceeds to the Company of approximately $184.9 million. Collectively, the net proceeds are in use to fund the Company's exploration, development and acquisition program and for general corporate purposes.

On and after June 1, 2018, the Company may redeem some or all of the Notes at a redemption price (expressed as a percentage of principal amount) equal to 100%, plus accrued and unpaid interest to the redemption date.

The Original Notes and the 2013 Follow-on Notes were governed by an Indenture, dated as of May 18, 2012, by and among the Company and Wilmington Trust, National Association (the "Original Indenture"). The 2015 Mirror Notes were governed by an Indenture, dated as of May 18, 2015, by and among the Company and Wilmington Trust, National Association (the "Mirror Indenture"). The terms and conditions of the Mirror Indenture conform, in all material respects, to the terms and conditions set forth in the Original Indenture.

NOTE 5 COMMON AND PREFERRED STOCK

In August 2018, the Company's stockholders approved an amendment to the Company's Certificate of Incorporation to increase the number of authorized shares of common stock, from 450,000,000 to 675,000,000. As a result, the Company's Restated Certificate of Incorporation authorizes the issuance of up to 680,000,000 shares. The shares are classified in two classes, consisting of 675,000,000 shares of common stock, par value $0.001 per share, and 5,000,000 shares of preferred stock, par value $0.001 per share. The board of directors is authorized to establish one or more series of preferred stock, setting forth the designation of each such series, and fixing the relative rights and preferences of each such series. The Company has neither designated nor issued any shares of preferred stock.

Common Stock

The following is a schedule of changes in the number of shares of common stock outstanding since the beginning of 2016:

	December 31,		
	2018	2017	2016
Beginning Balance	66,791,633	63,259,781	63,120,384
Repurchases of Common Stock	(7,359,953)	—	—
Stock Options Exercised - Net	62,500	—	—
Restricted Stock Grants	3,295,302	911,355	2,109,814
Debt Exchanges	136,063,799	—	—
Equity Offerings	96,926,019	—	—
Stock Consideration for Acquisitions of Oil and Natural Gas Properties	83,730,539	—	—
Legal Settlement	—	3,000,000	—
Other Surrenders - Tax Obligations	(266,683)	(270,510)	(375,875)
Other Forfeitures	(910,086)	(108,993)	(1,594,542)
Ending Balance	378,333,070	66,791,633	63,259,781

2018 Activity

In 2018, 0.3 million shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with their restricted stock awards. The total value of these shares was approximately $0.7 million, which is based on the market prices on the dates the shares were surrendered.

During January 2018, 0.9 million shares of common stock were forfeited in connection with the resignation of the Company's former interim chief executive officer and chief financial officer. The total amount of share-based compensation expense that was reversed in connection with his resignation was approximately $1.2 million.

Exchange Transactions

On May 15, 2018, as a part of closing the Exchange Agreement (see Note 4), the Company issued 103.2 million shares of the Company's common stock to the Supporting Noteholders as partial consideration for their exchange of Unsecured Notes.

In 2018, the Company issued an additional 32.8 million shares of the Company's common stock to various noteholders, through other privately negotiated exchange transactions, as consideration for the exchange of Unsecured Notes (see Note 4).

Equity Offerings

On April 10, 2018, the Company completed an underwritten public offering of common stock (the “Public Offering”) pursuant to which it issued 58.7 million shares of common stock and received net proceeds of $84.5 million after underwriting discounts, commissions, and offering expenses. On April 16, 2018, the underwriters exercised their option to purchase an additional 3.6 million shares and the Company received additional net proceeds of $5.2 million after underwriting discounts.

On May 15, 2018, in connection with the closing of the Exchange Agreement, the Company issued 34.7 million shares to various investors through subscription agreements for net proceeds of $52.0 million.

Acquisitions

On June 4, 2018, the Company issued 6.0 million shares of common stock as a part of the purchase price for the purchase of oil and gas properties under the purchase and sale agreement with Salt Creek Oil and Gas, LLC (see Note 3).

On September 17, 2018, the Company issued 25.8 million shares of common stock as a part of the purchase price for the purchase of oil and gas properties under the purchase and sale agreements for the Pivotal Acquisition (see Note 3).

On October 1, 2018, the Company issued 51.5 million shares of common stock as a part of the purchase price for the purchase of oil and gas properties under the purchase and sale agreement for the W Energy Acquisition (see Note 3).

2017 Activity

In 2017, 0.3 million shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with their restricted stock awards. The total value of these shares was approximately $0.7 million, which is based on the market prices on the dates the shares were surrendered.

In 2017, 3.0 million shares of common stock were issued in connection with a legal settlement with the Company's former chief executive officer.

In 2017, 0.1 million shares of common stock were forfeited by our interim chief executive officer and chief financial officer in connection with a performance-based vesting metric that was not achieved under a restricted stock award.

2016 Activity

In 2016, 0.4 million shares of common stock were surrendered by certain employees of the Company to cover tax obligations in connection with their restricted stock awards. The total value of these shares was approximately $1.4 million, which is based on the market prices on the dates the shares were surrendered.

In 2016, 1.5 million restricted shares of common stock were forfeited in connection with the termination of the employment of the Company's former chief executive officer. The total amount of share-based compensation expense that was reversed in connection with the termination was approximately $1.8 million.

Stock Repurchase Program

In May 2011, the Company's board of directors approved a stock repurchase program to acquire up to $150.0 million of the Company's outstanding common stock. The stock repurchase program allows the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions.

In 2018, the Company repurchased 7.4 million shares of its common stock under the stock repurchase program from the Pivotal Entities and W Energy (see Note 7) at a cost of approximately $23.9 million, of which, $1.7 million was recorded as a settlement of contingent consideration liabilities. These shares are now included in the Company's pool of authorized but unissued shares. In 2017 and 2016, the Company did not repurchase shares of its common stock under the stock repurchase program.

NOTE 6 STOCK OPTIONS/STOCK-BASED COMPENSATION AND WARRANTS

On July 19, 2018, the board of directors approved the Company's new 2018 Equity Incentive Plan (the "2018 Plan"), which was subsequently approved at the 2018 annual meeting of stockholders. 15,000,000 shares were authorized for grant under the 2018 Plan, plus the 769,775 shares remaining available for future grants under the Company's predecessor 2013 Incentive Plan (the "2013 Plan") on the date the shareholders approved the 2018 Plan. No future awards will be made under the 2013 Plan. The 2018 Plan is intended to provide a means whereby the Company may be able, by granting equity and other types of awards, to attract, retain and motivate capable and loyal employees, non-employee directors, consultants and advisors of the Company, for the benefit of the Company and its shareholders. As of December 31, 2018 there were 15.7 million shares available for future awards under the 2018 Plan.

Restricted Stock Awards Subject Only to Time-Based Vesting

During the years ended December 31, 2018, 2017 and 2016, the Company issued 1,050,355, 911,355 and 2,109,814, respectively, restricted shares of common stock subject only to time-based vesting under the equity plans as compensation to officers, employees and directors of the Company. Unvested restricted shares vest over various terms with all restricted shares vesting no later than June 2021. As of December 31, 2018, there was approximately $1.1 million of total unrecognized compensation expense related to such unvested restricted stock that will be recognized over a weighted-average period of approximately 1.1 years. The Company has historically assumed a zero percent forfeiture rate, thus recognizing forfeitures as they occur, for restricted stock due to the small number of officers, employees and directors that have received restricted stock awards.

The following table reflects the outstanding restricted stock awards subject only to time-based vesting and activity related thereto for the years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31, 2018		Year Ended December 31, 2017		Year Ended December 31, 2016	
	Number of Shares	**Weighted-Average Price**	**Number Of Shares**	**Weighted-Average Price**	**Number Of Shares**	**Weighted-Average Price**
Restricted Stock Awards:						
Restricted Shares Outstanding at the Beginning of the Year	1,721,533	$ 3.65	1,905,104	$ 4.59	2,365,396	$ 7.15
Shares Granted	1,050,355	2.67	911,355	2.10	2,109,814	3.83
Shares Forfeited	(910,086)	3.97	(108,993)	3.59	(1,594,542)	4.67
Lapse of Restrictions	(1,229,043)	3.04	(985,933)	4.05	(975,564)	7.34
Restricted Shares Outstanding at the End of the Year	632,759	$ 2.73	1,721,533	$ 3.65	1,905,104	$ 4.59

Stock Option Awards

On November 1, 2007, the board of directors granted options to purchase 560,000 shares of the Company's common stock under the Company's 2006 Incentive Stock Option Plan. The Company granted options to purchase 500,000 shares of the Company's common stock to members of the board and options to purchase 60,000 shares of the Company's common stock to one employee pursuant to an employment agreement. These options were granted at a price of $5.18 per share and were fully vested on the grant date. On November 1, 2017, the remaining options expired. The board of directors previously determined that no future grants will be made pursuant to the 2006 Incentive Stock Option Plan.

On February 12, 2016, the board of directors granted options to purchase 250,000 shares of the Company's common stock under the Company's 2013 Plan. The Company granted options to purchase 250,000 shares of the Company's common stock to one of its board members in connection with his appointment as chairman of the board of directors in January 2016. These options were granted with an exercise price of $2.79 per share and were fully vested on the grant date. As a result of the options being fully vested on the grant date, the Company recorded share-based compensation expense of $0.4 million for the year ended December 31, 2016. In August 2018, all 250,000 stock options were exercised pursuant to a net exercise, whereby 187,500 shares were surrendered to cover the aggregate exercise price and the remaining 62,500 shares were issued to the holder.

Changes in stock option awards for the years ended December 31, 2018, 2017, and 2016 were as follows:

	Stock Option Awards	Weighted-Average Price		Weighted Average Contractual Term	Intrinsic Value	
Outstanding as of December 31, 2015(1)	141,872	$	5.18	1.8	$	—
Granted	250,000	$	2.79			
Exercised	—	—				
Expired or canceled	—	—				
Forfeited	—	—				
Outstanding as of December 31, 2016(1)	391,872	$	3.66	2.9	$	—
Granted	—	—				
Exercised	—	—				
Expired or canceled	(141,872)	—				
Outstanding as of December 31, 2017(1)	250,000	$	2.79	1.0	$	—
Granted	—	—				
Exercised	(250,000)	—				
Expired or canceled	—	—				
Outstanding as of December 31, 2018	—	—		0.0	—	

(1) All of the stock options outstanding were vested and exercisable at the end of the period.

Performance Equity Awards

In 2018, the Company granted performance stock awards as compensation to certain officers and employees of the Company. The performance stock awards are restricted and vest contingent on the continued service of the recipients through the vesting dates under the awards, which are March 15 of 2019, 2020 and 2021. Additionally, the number of shares that will vest under these performance stock awards depends on two separate defined performance criteria. Shares under the Performance-Based Restricted Share Grant I (“Performance Award I”) vest contingent on the Company’s fourth quarter annualized Adjusted EBITDA as compared to specified targets. Performance Award I contains both service and performance vesting conditions. The Company assessed the probability of achieving the performance condition as of December 31, 2018 using its internal financial forecasts. Shares under the Performance-Based Restricted Share Grant II (“Performance Award II”), as it was originally granted, were to vest contingent on the Company’s average closing stock price for the last twenty trading days of 2018 compared to specified targets.

The following table summarizes the Performance Award I activity for the year ended December 31, 2018:

	Year Ended December 31, 2018	
	Number of Shares	Weighted-Average Grant Date Fair Value (per Award)
Outstanding as of 12/31/2017	—	$ —
Shares Granted	1,013,500	2.70
Lapse of Restrictions	—	—
Shares Forfeited	—	—
Outstanding as of 12/31/2018	1,013,500	$ 2.70

The fair value of the Performance Award I is estimated using the fair value on the grant date. The Company records the expense of the Performance Award I on a graded vesting basis over the requisite service period. Any Performance Award I awards that do not become earned will terminate, expire and otherwise be forfeited by the participants. For the year ended December 31, 2018, the Company recorded compensation expense related to Performance Award I awards of $1.1 million. At December 31, 2018, there was $1.6 million of total unrecognized compensation expense related to these awards.

The following table summarizes the Performance Award II activity for the year ended December 31, 2018:

	Year Ended December 31, 2018	
	Number of	Weighted-Average Grant Date Fair Value

	Shares	**(per Award)**	
Outstanding as of 12/31/2017	—	$	—
Shares Granted	1,018,500	1.67	
Lapse of Restrictions	—	—	
Shares Forfeited	—	—	
Outstanding as of 12/31/2018	1,018,500	$	1.67

The fair value of the Performance Award II was estimated using a Monte Carlo simulation at the grant date. The Company records the expense of the Performance Award II on a graded vesting basis over the requisite service period. Any Performance Award II awards that do not become earned will terminate, expire and otherwise be forfeited by the participants. For the year ended December 31, 2018, the Company recorded compensation expense related to Performance Award II awards of $0.7 million. At December 31, 2018, there was $2.5 million of total unrecognized compensation expense related to these awards.

In December 2018, the compensation committee of the board of directors modified Performance Award II such that the shares subject thereto now vest contingent on the Company's average closing stock price meeting specified targets for any consecutive twenty trading day period ending on or before December 31, 2019. The grant date fair value of the modified Performance

Award II shares was estimated using Monte Carlo simulations. This resulted in incremental compensation expense of $1.8 million as a result of the modification to both employees' and directors' Performance Award II shares, which will be expensed over the requisite service periods.

The assumptions used to estimate the fair value of the Performance Award II granted as of the date presented are as follows:

		Pre-Modification	**At Modification**
	June 1, 2018	**December 19, 2018**	**December 19, 2018**
Risk-Free Interest Rate	2.10%	2.35 %	2.62 %
Dividend Yield	— %	— %	— %
Expected Volatility	100.00%	80.00 %	85.00 %
Company's Closing Stock Price on Grant Date	$ 2.70	$ 2.22	$ 2.22

In 2018, the Company granted performance stock awards consisting of an aggregate of 176,100 shares as compensation to certain directors of the Company. These performance stock awards are set up with the same specified targets as the Performance Award II for officers and employees described above. These performance stock awards are restricted and vest contingent on continued service of the recipient through the vesting date, and dependent on the performance relative to the stock price targets for the Performance Award II. For the year ended December 31, 2018, the Company recorded compensation expense related to Performance Award II awards of $0.2 million. At December 31, 2018, there was $0.3 million of total unrecognized compensation expense related to these awards.

NOTE 7 RELATED PARTY TRANSACTIONS

Exchange Agreement

On January 31, 2018, the Company entered into an exchange agreement that was subsequently amended (as amended, the “Exchange Agreement”) with holders (the “Supporting Noteholders”) of approximately $496.7 million, or 71%, of the aggregate principal amount of its outstanding 8.000% senior unsecured notes due 2020 (the “Unsecured Notes”), pursuant to which the Supporting Noteholders agreed to exchange all of the Unsecured Notes held by each such Supporting Noteholder for approximately $155.0 million of its common stock and approximately $344.3 million in aggregate principal amount of new 8.500% senior secured second lien notes due 2023 (the “Second Lien Notes”) (such exchange, the “Exchange Transaction”). Closing under the Exchange Agreement occurred on May 15, 2018.

TRT Holdings, Inc. (“TRT”), Cresta Investments, LLC and Robert B. Rowling (together, the “TRT Noteholders”) are Supporting Noteholders and received, upon consummation of the Exchange Transaction, in the aggregate, approximately 54.6 million shares of the Company’s common stock and approximately $125.3 million aggregate principal amount of Second Lien Notes in exchange for the $204.7 million of Unsecured Notes that they exchanged.

Two of the Company's directors, Michael Frantz and Mike Popejoy, are employed by TRT, and each of the TRT Noteholders individually beneficially owned in excess of 5% of the Company's outstanding common stock when the Exchange Agreement was entered into. The principal amounts of any Second Lien Notes held by the TRT Noteholders as of December 31, 2018 are included in the Company's long-term debt balances, and the Company's interest expense includes interest attributable to any Unsecured Notes and Second Lien Notes held by TRT during the applicable period.

The obligations of the Supporting Noteholders under the Exchange Agreement were subject to the conditions set forth in the Exchange Agreement, which were satisfied at or prior to closing, including (among others) the successful completion of an equity transaction (the "Equity Raise") comprised of $140.0 million in gross proceeds from the sale of the Company's common stock, including the funding of up to $52.0 million of commitments received under the Subscription Agreements (as defined below).

Subscription Agreements and Equity Raise

On January 31, 2018, and in connection with the Exchange Transaction, the Company and Bahram Akradi (the Chairman of its board of directors), Michael Reger (who subsequently joined the Company as an executive officer in May 2018), TRT and certain other investors each entered into subscription agreements (the "Subscription Agreements") whereby such investors agreed to purchase up to $40.0 million of the Company's common stock at a price per share equal to the lowest price per share in the Equity Raise, and subject to the closing of the Exchange Transaction. Pursuant to their respective Subscription Agreements, Mr. Akradi purchased $12.0 million of the Company's common stock, Mr. Reger purchased $10.0 million of the Company's common stock, and TRT purchased $10.0 million of the Company's common stock. Based on the pricing of the Equity Raise, the lowest price of which was $1.50 per share, Mr. Akradi purchased 8.0 million shares, Mr. Reger purchased 6.7 million shares and TRT purchased 6.7 million shares. Mr. Akradi and TRT each beneficially owned in excess of 5% of the Company's outstanding common stock when their respective Subscription Agreements were entered into.

On April 10, 2018, to satisfy, in part, the Company's obligation to complete the Equity Raise, the Company completed an underwritten public offering (the "Offering"), whereby it sold 58,666,667 shares of its common stock at a public offering price of $1.50 per share. As part of the Offering, Mr. Akradi purchased 1.0 million shares of the Company's common stock from the underwriters of the Offering for an aggregate purchase price of $1.5 million. Mr. Akradi beneficially owned in excess of 5% of the Company's outstanding common stock when he purchased such shares.

Registration Rights

In accordance with the terms of the Exchange Agreement, at the closing of the Exchange Transaction, the Company entered into registration rights agreements with (i) the Supporting Noteholders, including the TRT Noteholders, pursuant to which the Company agreed to file with the SEC a registration statement registering for resale the shares of common stock and the Second Lien Notes issued in the Exchange Transaction, and (ii) the TRT Noteholders and an affiliate of TRT, pursuant to which the Company agreed to file with the SEC a registration statement registering for resale all of the shares of common stock held by the TRT Noteholders and such affiliate, excluding shares of common stock that the TRT Noteholders received pursuant to the Exchange Transaction. The required registration statements were filed and declared effective by the SEC during 2018.

Share Repurchases

In November 2018, the Company repurchased shares of Company common stock as follows: (i) an aggregate of 4,494,624 shares from Pivotal Williston Basin, L.P. and Pivotal Williston Basin II, L.P. (collectively, the "Pivotal Entities") for cash consideration of $13,933,334, and (ii) 2,865,329 shares from W Energy Partners LLC ("W Energy") for cash consideration of $9,999,999. The repurchased shares were originally issued by the Company as partial consideration for the Pivotal Acquisition and W Energy Acquisition described in Note 3 above. The Pivotal Entities and W Energy each beneficially owned in excess of 5% of the Company's outstanding common stock at the time of these repurchase transactions.

The Company's Audit Committee is responsible for approving all transactions involving related parties, including each of the transactions identified above.

NOTE 8 COMMITMENTS & CONTINGENCIES

Litigation

The Company is engaged in various proceedings incidental to the normal course of business. Due to their nature, such legal proceedings involve inherent uncertainties, including but not limited to, court rulings, negotiations between affected parties and governmental intervention. Based upon the information available to the Company and discussions with legal counsel, it is the Company’s opinion that the outcome of the various legal actions and claims that are incidental to its business will not have a material impact on the Company’s financial position, results of operations or cash flows. Such matters, however, are subject to many uncertainties, and the outcome of any matter is not predictable with assurance.

The Company’s interests in certain crude oil and natural gas leases from the State of North Dakota are subject to an ongoing dispute over the ownership of minerals underlying the bed of the Missouri River within the boundaries of the Fort Berthold Reservation. The ongoing dispute is between the State of North Dakota and three affiliated tribes, both of whom have purported to lease mineral rights in tracts of riverbed within the reservation boundaries. In the event the ongoing dispute results in a final judgment that is adverse to the Company’s interests, the Company would be required to reverse approximately $5.1 million in revenue (net of accrued taxes) that has been accrued since the first quarter of 2013 based on the Company’s purported interest in the crude oil and natural gas leases at issue. Due to the long-term nature of this title dispute, the $5.1 million in accounts receivable is included in “Other Noncurrent Assets, Net” on the balance sheets. The Company fully maintains the validity of its interests in the crude oil and natural gas leases.

In December 2018, the U.S. District Court for the Southern District of New York dismissed, with prejudice, a class action that was originally brought in August 2016 by plaintiff Jeffrey Fries, individually and on behalf of all others similarly situated, against the Company, Michael Reger (the Company's former chief executive officer), and Thomas Stoelk (the Company's former chief financial officer and interim chief executive officer) as defendants. The original complaint was amended by plaintiff in July 2017. The court granted the Company’s motion to dismiss the amended complaint in January 2018, but permitted plaintiff the opportunity to further amend the complaint. A second amended complaint was filed by plaintiffs in January 2018. The court granted the Company's motion to dismiss the second amended complaint, with prejudice, in December 2018. The complaints purported to bring a federal securities class action on behalf of a class of persons who acquired the Company’s securities between March 1, 2013 and August 15, 2016, and sought to recover damages caused by defendants’ alleged violations of the federal securities laws and to pursue remedies under Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 promulgated thereunder. Plaintiff did not appeal the court's dismissal of the second amended complaint, and this matter is now fully dismissed.

NOTE 9 ASSET RETIREMENT OBLIGATION

The Company has asset retirement obligations associated with the future plugging and abandonment of proved properties and related facilities. Initially, the fair value of a liability for an ARO is recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, an adjustment to the full cost pool is recognized. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted risk-free discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO, a corresponding adjustment is made to the oil and gas property balance. For example, as the Company analyzes actual plugging and abandonment information, the Company may revise its estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of its wells. During 2018 there were no adjustments to the aforementioned assumptions requiring revisions of previous estimates. During 2017, the Company increased its existing ARO by $0.6 million due to an increase in the estimated costs to plug and abandon the Company’s wells.

The following table summarizes the Company’s asset retirement obligation transactions recorded during the years ended December 31, 2018 and 2017.

	December 31,			
	2018		**2017**	
Beginning Asset Retirement Obligation	$	9,128,128	$	7,508,300
Liabilities Acquired During the Period	1,736,579		—	

Liabilities Incurred During the Period	1,117,562	578,441
Revision of Estimates	—	609,351
Accretion of Discount on Asset Retirement Obligations	683,445	536,732
Liabilities Settled During the Period	(164,854)	(104,696)
Ending Asset Retirement Obligation	$ 12,500,860	$ 9,128,128

NOTE 10 INCOME TAXES

Income taxes are accounted for under the asset and 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 losses and tax credit carry-forwards. Under this method, 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 (loss) in the period that includes the enactment date.

The income tax provision (benefit) for the years ended December 31, 2018, 2017, and 2016 consists of the following:

(in thousands)	2018		2017		2016	
Current						
Federal	$	(420)	$	(785)	$	(1,402)
State	—		—		—	
Deferred						
Federal	91,958		126,501		(99,299)	
State	11,636		(12,983)		(9,707)	
Valuation Allowance	(103,229)		(114,303)		109,006	
Total Tax Benefit	$	(55)	$	(1,570)	$	(1,402)

The following is a reconciliation of the reported amount of income tax benefit for the years ended December 31, 2018, 2017, and 2016 to the amount of income tax expenses that would result from applying the statutory rate to pretax income (loss).

(in thousands)	2018		2017		2016	
Income (Loss) Before Taxes and NOL	$	143,634	$	(10,764)	$	(294,896)
Federal Statutory Rate	21.00%		35.00%		35.00%	
Taxes Computed at Federal Statutory Rates	30,163		(3,767)		(103,214)	
State Taxes, Net of Federal Taxes	9,143		(8,476)		(6,306)	
Share Based Compensation Tax Deficiency	316		—		(835)	
Federal Rate Reduction	—		124,493		—	
Section 382 Limitation	63,573		—		—	
Other	(21)		483		(53)	
Valuation Allowance	(103,229)		(114,303)		109,006	
Reported Tax Benefit	$	(55)	$	(1,570)	$	(1,402)

The Company’s May 15, 2018 closing under the Exchange Agreement and related transactions triggered an ownership change within the meaning of Section 382 of the Internal Revenue Code (“IRC”) due to the share issuances that resulted from the Exchange Agreement and related transactions. In general, an ownership change, as defined in IRC Section 382, results from a transaction or series of transactions over a three-year period resulting in an ownership change of more than 50% of the outstanding stock of a company by certain stockholders or public groups. Since the Company has experienced an ownership change, utilization of net operating losses (“NOL”) and other tax carryforward attributes are subject to an annual limitation. Accordingly, the Company reduced its deferred tax assets and related valuation allowance by $63.6 million during 2018.

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. During 2018, in evaluating whether it was more likely than not that the Company’s net deferred tax assets were realized through future net income, management considered all available positive and negative evidence, including (i) its earnings history, (ii) its ability to recover net operating loss carry-forwards, (iii) the existence of significant proved oil and natural gas reserves, (iv) its ability to use tax planning strategies, (v) its current price protection utilizing oil hedges, (vi) its future revenue and operating cost projections and (vii) the current market prices for oil and natural gas. Based on all the evidence available, management determined it was more likely than not that the net deferred tax assets, other than the deferred tax asset related to the Company’s alternative minimum tax credit, were not realizable, therefore a valuation allowance of $123.7 million was recorded at December 31, 2018.

At December 31, 2018, the Company had a net operating loss carryforward for federal income tax purposes of $370.5 million, which is net of the IRC Section 382 limitation and state NOL carryforwards of $555.3 million. The determination of the state NOL carryforwards is dependent upon apportionment percentages and state laws that can change from year to year and that can thereby impact the amount of such carryforwards. If unutilized, the federal net operating losses will expire from 2031 to 2037 and the state net operating losses will expire from 2019 to 2037.

The significant components of the Company's deferred tax assets (liabilities) were as follows:

	Year Ended December 31,	
(in thousands)	**2018**	**2017**
Net Operating Loss (NOLs) and Tax Credit Carryforwards	$ 96,700	$ 174,865
Share Based Compensation	146	797
Accrued Interest	637	1,144
Allowance for Doubtful Accounts	1,279	1,360
Crude Oil and Natural Gas Properties and Other Properties	16,904	42,329
Interest Carryforwards	40,614	—
Derivative Instruments	(31,981)	7,393
Other	(145)	(140)
Total Net Deferred Tax Assets (Liabilities) Before Valuation Allowance	124,154	227,748
Valuation Allowance	(123,734)	(226,963)
Total Net Deferred Tax Assets	$ 420	$ 785

Tax benefits are recognized only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50 percent likely to be realized upon ultimate settlement. Unrecognized tax benefits are tax benefits claimed in the Company's tax returns that do not meet these recognition and measurement standards. The Company has no liabilities for unrecognized tax benefits.

The Company's policy is to recognize potential interest and penalties accrued related to unrecognized tax benefits within income tax expense. For the years ended December 31, 2018, 2017 and 2016, the Company did not recognize any interest or penalties in its statements of operations, nor did it have any interest or penalties accrued in its balance sheet at December 31, 2018 and 2017 relating to unrecognized benefits.

The tax years 2018, 2017, 2016, and 2015 remain open to examination for federal income tax purposes and by the other major taxing jurisdictions to which the Company is subject. Additionally, NOLs from 2011-2014 could be adjusted in the future when such NOLs are utilized.

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (the “Act”) which made significant changes that affect the Company, resulting in significant modifications to existing law. The Company’s financial statements for the years ended December 31, 2018 and 2017 reflect the effects of the Act which includes a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018, as well as other changes. As of December 31, 2017, the impact of this change was a net reduction in deferred tax assets of $124.5 million, before valuation allowance. The Company's valuation allowance was reduced by $125.3 million. Due to the Company's valuation allowance position, the net effect of the Act was a tax benefit of $0.8 million.

As a result of the Act, the Company is also subject to certain statutory restrictions on its 2018 current interest and debt loss deductions under IRC Section 163(j) which limits interest deductions to business interest income plus 30% of adjusted taxable income. Deferred interest expense carryforwards do not expire, but can only be utilized in future years when adjusted taxable income provides excess limitation. For the year ended December 31, 2018, the company generated a $40.6 million interest expense carryforward attribute, which has a full valuation allowance. The Act also repeals the corporate alternative minimum tax for tax years beginning after December 31, 2017 and provides that prior alternative minimum tax credits will be refundable. The Company has credits that are expected to be refunded between 2018 and 2021 as a result of the Act and monetization opportunities under current tax laws. In 2018, the Company utilized $0.4 million of its alternative minimum tax credit. The Company has an additional $0.4 million of alternative minimum tax credits that will be refunded in future years.

NOTE 11 OPERATING LEASES

The Company leases office space under an operating lease expiring in 2021. Minimum future annual lease payments for the calendar years presented are as follows:

	Amount	
2019	$	352,000
2020	361,000	
2021	340,000	
Total	$	1,053,000

The following has been recorded to rent expense for the periods presented:

	December 31,					
	2018		2017		2016	
Rent Expense	$	328,000	$	369,000	$	320,000

The Company's has an office space lease agreement that contains scheduled escalation in lease payments during the term of the lease. In accordance with GAAP, the Company records rent expense on a straight-line basis and a deferred rent liability for the

NOTE 12 FAIR VALUE

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs. The Company uses a fair value hierarchy based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value which are the following:

Level 1 - Quoted prices in active markets for identical assets or liabilities.

Level 2 - Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

Financial Assets and Liabilities

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2018 and 2017.

	Fair Value Measurements at Using December 31, 2018 Using					
	Quoted Prices In Active Markets for Identical Assets (Liabilities) (Level 1)		Significant Other Observable Inputs (Level 2)		Significant Unobservable Inputs (Level 3)	
Commodity Derivatives – Current Assets (crude oil price and basis swaps)	$	—	$	115,870,246	$	—
Commodity Derivatives – Noncurrent Assets (crude oil price swaps)	—		61,842,846		—	
Contingent Consideration – Current Liabilities	—		—		(58,068,917)	
Debt Exchange Derivatives – Current Liabilities	—		—		(18,183,212)	
Total	$	—	$	177,713,092	$	(76,252,129)

	Fair Value Measurements at December 31, 2017 Using		
	Quoted Prices In Active Markets for Identical Assets (Liabilities) (Level	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)

1)

Commodity Derivatives – Current Liabilities (crude oil price swaps)	$	—	$	(18,681,891)	$	—
Commodity Derivatives – Noncurrent Liabilities (crude oil price swaps)	—		(11,496,929)		—	
Total	$	—	$	(30,178,820)	$	—

Commodity Derivatives. The Level 2 instruments presented in the tables above consist of commodity derivative instruments (see Note 13). The fair value of the Company's derivative financial instruments is determined based upon future prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties' nonperformance risk is evaluated. The fair value of all derivative contracts is reflected on the balance sheet. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent twelve months.

Contingent Consideration. The fair value of the contingent consideration potentially payable by the Company in connection with both the Pivotal Acquisition and W Energy Acquisition, which in certain circumstances we are permitted to settle in either cash or shares of common stock, was determined using Monte Carlo simulation models. Significant inputs used in the fair value measurements include (i) the Company's common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) volatility of the Company's common stock, and (iv) expected average daily trading volumes. The expected volatility and average daily trading volumes used in the valuation were unobservable in the marketplace and significant to the valuation methodology, and the contingent consideration's fair value was therefore designated as Level 3 in the valuation hierarchy. Changes in the fair value of this liability is included in other income (expense) in the Company's statements of operations.

Debt Exchange Derivatives. The Company had embedded derivatives related to a number of its separately negotiated exchange agreements with holders of the Company's Unsecured Notes. The exchange agreements contained provisions whereby if at the end of the applicable restricted sale period the Company's common stock trades below specified levels, the Company may be required to pay additional consideration to the holder in the form of cash or additional shares of common stock. The Company determined these provisions were not clearly and closely related to the shares of common stock issued under the exchange agreements and, therefore, bifurcated these embedded features and reflected them at fair value in the financial statements. Prior to their settlements, the fair values of these embedded derivatives were determined using Monte Carlo simulations which considered various inputs including (i) the Company's common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) volatility of the Company's common stock, and (iv) expected average daily trading volumes. The expected volatility and average daily trading volumes used in the valuation were unobservable in the marketplace and significant to the valuation methodology, and the embedded derivatives' fair value was therefore designated as Level 3 in the valuation hierarchy. Changes in the fair values of these liabilities are included in other income (expense) in the Company's statements of operations.

The following table summarizes the changes in fair value of the Company's financial instruments classified as Level 3 in the fair value hierarchy:

(in thousands)	**Year Ended December 31, 2018**	
Beginning Balance	$	—
Debt exchange derivative liability	(19,354)	
Contingent consideration	(32,312)	
Debt exchange derivative liability settlements	1,769	
Contingent consideration settlements	3,211	
Change in fair value of debt exchange derivative liability	(598)	
Change in fair value of contingent consideration	(28,968)	
Ending Balance	$	(76,252)

Fair Value of Other Financial Instruments

The carrying amount of the Company's long-term debt reported in the balance sheet at December 31, 2018 is $830.2 million, which includes $690.2 million of second lien notes and $140.0 million of borrowings under the Company's revolving credit facility (see Note 4). The fair value of the Company's second lien notes, which are publicly traded ("level 1"), is $670.8 million at December 31, 2018. The Company's revolving credit facility approximates its fair value because of its floating rate structure.

Non-Financial Assets and Liabilities

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC 410. The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and natural gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligations liability is deemed to use Level 3 inputs. Asset retirement obligations incurred and acquired during the year ended December 31, 2018 were approximately $2.9 million.

The Company accounts for acquisitions of oil and natural gas properties under the acquisition method of accounting. Accordingly, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisitions are expensed as incurred. The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair value of oil and natural gas properties. The fair value of these properties is measured using a discounted cash flow model that converts future cash flows to a single discounted amount. These assumptions represent Level 3 inputs under the fair value hierarchy. See Note 3 for additional discussion of the Company's acquisitions of oil and natural gas properties during the year ended December 31, 2018 and discussion of the significant inputs to the valuations.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. There were no transfers of financial assets or liabilities between Level 1, Level 2 or Level 3 inputs for the years ended December 31, 2018 and 2017.

NOTE 13 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes commodity price swaps, basis swaps, swaptions and collars (purchased put options and written call options) to (i) reduce the effects of volatility in price changes on the crude oil commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending.

All derivative instruments are recorded on the Company’s balance sheet as either assets or liabilities measured at their fair value (see Note 12). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in the fair value are recognized in the revenues section of the Company’s statements of operations as a gain or loss on derivative instruments. Mark-to-market gains and losses represent changes in fair values of derivatives that have not been settled. The Company’s cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company’s derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

The following table presents cash settlements on matured or liquidated derivative instruments and non-cash gains and losses on open derivative instruments for the periods presented. Cash receipts and payments below reflect proceeds received upon early liquidation of derivative positions and gains or losses on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price of matured contracts. Non-cash gains and losses below represent the change in fair value of derivative instruments which continue to be held at period-end and the reversal of previously recognized non-cash gains or losses on derivative contracts that matured or were liquidated during the period.

	Year Ended December 31,					
	2018		**2017**		**2016**	
Cash Received (Paid) on Settled Derivatives (1)	$	(22,885,743)	$	3,776,788	$	61,528,201
Non-Cash Mark-to-Market Gain (Loss) on Derivatives	207,891,912		(18,443,443)		(76,346,935)	
Gain (Loss) on Derivative Instruments, Net	$	185,006,169	$	(14,666,655)	$	(14,818,734)

(1) Net cash receipts for the year ended December 31, 2017 includes approximately $0.7 million of proceeds received from crude oil derivative contracts that were settled prior to their contractual maturities as a result of the termination of the Company's prior revolving credit facility during 2017.

The Company has master netting agreements on individual commodity contracts with certain counterparties and therefore the current asset and liability are netted on the balance sheet and the non-current asset and liability are netted on the balance sheet for contracts with these counterparties.

As of December 31, 2018, the Company had a total volume on open commodity swaps of 12.3 million barrels at a weighted average price of approximately $62.31 per barrel. The following table reflects the weighted average price of open commodity price swap derivative contracts as of December 31, 2018, by year with associated volumes.

Weighted Average Price Of Open Commodity Swap Contracts

Year	**Volumes (Bbl)**	**Weighted Average Price ($)**
2019	6,851,730	63.32
2020	4,186,080	61.01
2021 and beyond	1,310,100	61.18

In addition to the open commodity price swap contracts the Company has entered into basis swap contracts. Basis swaps fix the price differential between a published index price and the applicable local index price under which the Company's production is sold. The following table reflects open commodity basis swap contracts as of December 31, 2018.

Settlement Period	**Oil (Barrels)**	**Weighted Average Price ($)**
01/01/19 – 12/31/19	3,650,000	(2.41)

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at December 31, 2018 and 2017, respectively. Certain amounts may be presented on a net basis on the financial statements when such amounts are with the same counterparty and subject to a master netting arrangement:

		December 31, Estimated Fair Value			
Type of Crude Oil Contract	**Balance Sheet Location**	**2018**		**2017**	
Derivative Assets:					
Swap Price Contracts	Current Assets	$	108,513,784	$	—
Basis Swap Contracts	Current Assets	7,356,462		—	
Swap Price Contracts	Noncurrent Assets	61,842,846		—	
Total Derivative Assets		$	177,713,092	$	—
Derivative Liabilities:					
Swap Price Contracts	Current Liabilities	$	—	$	(18,681,891)
Swap Price Contracts	Noncurrent Liabilities	—		(11,496,929)	
Total Derivative Liabilities		$	—	$	(30,178,820)

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. When the Company has netting arrangements with its counterparties that provide for offsetting payables against receivables from separate derivative instruments these assets and liabilities are netted on the balance sheet. The tables presented below provide reconciliation between the gross assets and liabilities and the amounts reflected on the balance sheet. The amounts presented exclude derivative settlement receivables and payables as of the balance sheet dates.

	Estimated Fair Value at December 31, 2018					
	Gross Amounts of Recognized Assets (Liabilities)		**Gross Amounts Offset in the Balance Sheet**		**Net Amounts of Assets (Liabilities) Presented in the Balance Sheet**	
Offsetting of Derivative Assets:						
	$	116,619,814	$	(749,568)	$	115,870,246

Current Assets						
Noncurrent Assets		61,857,470		(14,624)		61,842,846
Total Derivative Assets	$	178,477,284	$	(764,192)	$	177,713,092
Offsetting of Derivative Liabilities:						
Current Liabilities	$	(749,568)	$	749,568	$	—
Noncurrent Liabilities		(14,624)		14,624		—
Total Derivative Liabilities	$	(764,192)	$	764,192	$	—

Estimated Fair Value at December 31, 2017

	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets (Liabilities) Presented in the Balance Sheet
Offsetting of Derivative Assets:			
Current Assets	$ —	$ —	$ —
Noncurrent Assets	—	—	—
Total Derivative Assets	$ —	$ —	$ —
Offsetting of Derivative Liabilities:			
Current Liabilities	$ (18,681,891)	$ —	$ (18,681,891)
Noncurrent Liabilities	(11,496,929)	—	(11,496,929)
Total Derivative Liabilities	$ (30,178,820)	$ —	$ (30,178,820)

All of the Company's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements ("ISDAs") entered into with parties that are also lenders under the Company's revolving credit facility. The Company's obligations under the derivative instruments are secured pursuant to the revolving credit facility, and no additional collateral had been posted by the Company as of December 31, 2018. The ISDAs may provide that as a result of certain circumstances, such as cross-defaults, a counterparty may require all outstanding derivative instruments under an ISDA to be settled immediately. See Note 12 for the aggregate fair value of all derivative instruments that were in a net liability position at December 31, 2018 and 2017.

NOTE 14 EARNINGS PER SHARE

The following is a reconciliation of the numerator and denominator used to calculate basic earnings per share and diluted earnings per share for the years ended December 31, 2018, 2017, and 2016:

	2018			2017			2016		
	Net Income	Shares	Per Share	Net Loss	Shares	Per Share	Net Loss	Shares	Per Share
Basic EPS	143,689,235	236,206,457	$ 0.61	$ (9,193,772)	62,408,855	$ (0.15)	$ (293,493,708)	61,173,547	$ (4.80)
Dilutive Effect of Restricted Stock and Stock	—	567,454	—	—	—	—	—	—	—

Options												
Diluted EPS	$	143,689,235	236,773,911	$	0.61	$	(9,193,772)	62,408,855	$	(0.15)	$	(293,493,708)	61,173,547	$	(4.80)

For the year ended December 31, 2018, 2017 and 2016 restricted stock of 50,685, 1,109,511, and 829,313 shares of common stock were excluded from EPS due to the anti-dilutive effect, respectively.

NOTE 15 EMPLOYEE BENEFIT PLANS

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at the date of hire. The plan allows eligible employees to make pre-tax contributions up to 100% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 8% of an employee's compensation and may make additional discretionary contributions for eligible employees. Employees are 100% vested in the employer contributions upon receipt. The Company contributed approximately $0.2 million to the 401(k) plan for each the years ended December 31, 2018, 2017 and 2016, respectively.

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Exploration and Production Activities

Oil and gas sales reflect the market prices of net production sold or transferred with appropriate adjustments for royalties, net profits interest, and other contractual provisions. Production expenses include lifting costs incurred to operate and maintain productive wells and related equipment including such costs as operating labor, repairs and maintenance, materials, supplies and fuel consumed. Production taxes include production and severance taxes. Depletion of crude oil and natural gas properties relates to capitalized costs incurred in acquisition, exploration, and development activities. Results of operations do not include interest expense and general corporate amounts. The results of operations for the Company's crude oil and natural gas production activities are provided in the Company's related statements of income.

Costs Incurred and Capitalized Costs

The costs incurred in crude oil and natural gas acquisition, exploration and development activities are highlighted in the table below.

	December 31,		
(in thousands)	**2018**	**2017**	**2016**
Costs Incurred for the Year:			
Proved Property Acquisition and Other	$ 582,696	$ 15,722	$ 18,532
Unproved Property Acquisition	4,903	717	2,301
Development	260,945	139,532	63,621
Total	$ 848,545	$ 155,971	$ 84,454

Excluded costs for unproved properties are accumulated by year. Costs are reflected in the full cost pool as the drilling costs are incurred or as costs are evaluated and deemed impaired. The Company anticipates these excluded costs will be included in the depletion computation over the next five years. The Company is unable to predict the future impact on depletion rates. The following is a summary of capitalized costs excluded from depletion at December 31, 2018 by year incurred.

	December 31,			
(in thousands)	**2018**	**2017**	**2016**	**Prior Years**
Property Acquisition	$ 3,298	$ 71	$ 1	$ 937
Development	—	—	—	—

Total	$ 3,298	$ 71	$ 1	$ 937

Oil and Natural Gas Reserves and Related Financial Data

Information with respect to the Company’s crude oil and natural gas producing activities is presented in the following tables. Reserve quantities, as well as certain information regarding future production and discounted cash flows, were determined by Cawley, Gillespie & Associates, Inc., independent petroleum consultants based on information provided by the Company.

Oil and Natural Gas Reserve Data

The following tables present the Company's independent petroleum consultants' estimates of its proved crude oil and natural gas reserves. The Company emphasizes that reserves are approximations and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

	Natural Gas (MCF)	**Oil (BBLS)**	**BOE**
Proved Developed and Undeveloped Reserves at December 31, 2015	50,900,984	56,814,464	65,297,962
Revisions of Previous Estimates	(8,697,825)	(13,995,801)	(15,445,439)
Extensions, Discoveries and Other Additions	7,695,309	7,142,439	8,424,991
Purchases of Minerals in Place	960,758	640,108	800,234
Production	(4,026,899)	(4,325,919)	(4,997,069)
Proved Developed and Undeveloped Reserves at December 31, 2016	46,832,327	46,275,291	54,080,679
Revisions of Previous Estimates	8,838,976	889,814	2,362,977
Extensions, Discoveries and Other Additions	27,637,350	20,184,388	24,790,613
Production	(5,187,886)	(4,537,295)	(5,401,943)
Proved Developed and Undeveloped Reserves at December 31,	78,120,767	62,812,198	75,832,326

2017			
Revisions of Previous Estimates	425,564	3,469,733	3,540,660
Extensions, Discoveries and Other Additions	28,347,629	28,516,382	33,240,987
Purchases of Minerals in Place	37,397,266	25,965,285	32,198,163
Production	(9,224,766)	(7,790,182)	(9,327,643)
Proved Developed and Undeveloped Reserves at December 31, 2018	135,066,460	112,973,416	135,484,493
Proved Developed Reserves:			
December 31, 2015	33,619,954	36,573,821	42,177,148
December 31, 2016	32,808,111	32,245,139	37,713,158
December 31, 2017	46,518,005	38,592,506	46,345,507
December 31, 2018	82,314,664	62,497,051	76,216,162
Proved Undeveloped Reserves:			
December 31, 2015	17,281,030	20,240,643	23,120,815
December 31, 2016	14,024,216	14,030,152	16,367,521
December 31, 2017	31,602,762	24,219,692	29,486,819
December 31, 2018	52,751,796	50,476,365	59,268,331

Proved reserves are estimated quantities of crude oil and natural gas, which geological and engineering data indicate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are included for reserves for which there is a high degree of confidence in their recoverability and they are scheduled to be drilled within the next five years.

Notable changes in proved reserves for the year ended December 31, 2018 included the following:

•*Extensions and discoveries*. In 2018, total extensions and discoveries of 33.2 MMBOE were primarily attributable to successful drilling in the Williston Basin as well as the addition of proved undeveloped locations. Included in these extensions and discoveries were 6.8 MMBOE as a result of successful drilling in the Williston Basin and 26.4 MBOE as a result of additional proved undeveloped locations.

•*Purchases of minerals in place*. In 2018, total purchases of minerals in place of 32.2 MMBOE were primarily attributable to acquisitions of oil and natural gas properties (see Note 3).

•*Revisions to previous estimates*. In 2018, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 3.5 MMBOE. Included in these revisions were 1.4 MMBOE of upward adjustments caused by higher crude oil and natural gas prices and a 3.9 MMBOE upward adjustment attributable to well performance when comparing the Company's reserve estimates at December 31, 2018 to December 31, 2017 which was partially offset by 1.8 MMBOE of downward adjustments related to the removal of undeveloped drilling locations related to the 5 year rule.

Notable changes in proved reserves for the year ended December 31, 2017 included the following:

•*Extensions and discoveries*. In 2017, total extensions and discoveries of 24.8 MMBOE were primarily attributable to successful drilling in the Williston Basin as well as the addition of proved undeveloped locations. Included in these extensions and discoveries were 5.9 MMBOE as a result of successful drilling in the Williston Basin and 18.9 MMBOE as a result of additional proved undeveloped locations.

•*Revisions to previous estimates*. In 2017, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 2.4 MMBOE. Included in these revisions were 1.8 MMBOE of upward adjustments caused by higher crude oil and natural gas prices and a 3.1 MMBOE upward adjustment attributable to well performance when comparing the Company's reserve estimates at December 31, 2017 to December 31, 2016 which was partially offset by 2.5 MMBOE of downward adjustments related to the removal of undeveloped drilling locations related to the 5 year rule.

Notable changes in proved reserves for the year ended December 31, 2016 included the following:

•*Extensions and discoveries*. In 2016, total extensions and discoveries of 8.4 MMBOE were primarily attributable to successful drilling in the Williston Basin. Both the new wells drilled in these areas as well as the proved undeveloped locations added as a result of drilling increased the Company's proved reserves.

•*Purchases of minerals in place*. In 2016, total purchases of minerals in place of 0.8 MMBOE were primarily attributable to an acquisition with a third party.

•*Revisions to previous estimates*. In 2016, revisions to previous estimates decreased proved developed and undeveloped reserves by a net amount of 15.4 MMBOE. Included in these revisions were 15.7 MMBOE of downward adjustments caused by lower crude oil and natural gas prices and 3.4 MMBOE of downward adjustments related to the removal of undeveloped drilling locations related to the 5 year rule which was partially offset by a 3.6 MMBOE upward adjustment attributable to well performance when comparing the Company's reserve estimates at December 31, 2016 to December 31, 2015.

Standardized Measure of Discounted Future Net Cash Inflows and Changes Therein

The following table presents a standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved crude oil and natural gas were prepared in accordance with the provisions of ASC 932 *Extractive Activities - Oil and Gas*. Future cash inflows were computed by applying average prices of crude oil and natural gas for the last 12 months to estimated future production. Future production and development costs were computed by estimating the expenditures to be incurred in developing and producing the proved crude oil and natural gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions. Future income tax expenses were calculated by applying appropriate year end tax rates to future pretax cash flows relating to proved crude oil and natural gas reserves, less the tax basis of properties involved and tax credits and loss carry forwards relating to crude oil and natural gas producing activities. Future net cash flows are discounted at the rate of 10% annually to derive the standardized measure of discounted future cash flows. Actual future cash inflows may vary considerably, and the standardized measure does not necessarily represent the fair value of the Company's crude oil and natural gas reserves.

	December 31,					
(in thousands)	**2018**		**2017**		**2016**	
Future Cash Inflows	$	7,524,587	$	3,143,604	$	1,708,871
Future Production Costs	(2,605,279)		(1,265,525)		(775,535)	
Future Development Costs	(784,615)		(409,360)		(220,870)	
Future Income Tax Expense	(611,989)		(27,476)		(2,477)	
Future Net Cash Inflows	$	3,522,704	$	1,441,243	$	709,989
10% Annual Discount for Estimated Timing of Cash Flows	(1,643,061)		(687,257)		(330,963)	
Standardized Measure of Discounted Future Net Cash Flows	$	1,879,643	$	753,986	$	379,026

The twelve month average prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate the Company's reserves. The price of other liquids is included in natural gas. The prices for the Company's reserve estimates were as follows:

Natural Gas MCF		**Oil Bbl**	
$	4.50	$	61.23

December 31, 2018				
December 31, 2017	$	3.34	$	45.90
December 31, 2016	$	1.67	$	35.24

The expected tax benefits to be realized from utilization of the net operating loss and tax credit carryforwards are used in the computation of future income tax cash flows. As a result of available net operating loss carryforwards and the remaining tax basis of its assets at December 31, 2018, the Company's future income taxes were significantly reduced.

Changes in the Standardized Measure of Discounted Future Net Cash Flows at 10% per annum follow:

	December 31,		
(in thousands)	**2018**	**2017**	**2016**
Beginning of Period	$ 753,986	$ 379,026	$ 574,799
Sales of Oil and Natural Gas Produced, Net of Production Costs	(381,961)	(153,626)	(98,497)
Extensions and Discoveries	549,353	217,146	59,543
Previously Estimated Development Cost Incurred During the Period	115,542	46,834	23,272
Net Change of Prices and Production Costs	484,122	216,217	(174,656)
Change in Future Development Costs	(91,829)	(34,753)	57,481
Revisions of Quantity and Timing Estimates	66,185	28,915	(130,664)
Accretion of Discount	75,800	37,942	57,569
Change in Income Taxes	(296,571)	(3,617)	498
Purchases of Minerals in Place	502193	—	9,577
Other	102,825	19,903	105
End of Period	$ 1,879,643	$ 753,986	$ 379,026

QUARTERLY RESULTS OF OPERATIONS (UNAUDITED)

Quarterly data for the years end December 31, 2018 and 2017 is as follows:

	Quarter Ended			
	March 31,	**June 30,**	**September 30,**	**December 31,**
2018				
Total Revenues	$ 66,613,463	$ 66,845,899	$ 102,269,220	$ 443,195,914
Gain (Loss) on Derivative Instruments, Net	(20,271,451)	(42,202,788)	(43,148,073)	290,628,481
Total Operating Expenses	40,708,240	50,528,032	66,672,662	88,387,075
Income from Operations	25,905,223	16,317,867	35,596,558	354,808,839
Other Income (Expense)	(22,940,126)	(112,865,565)	(16,617,985)	(136,570,576)
Income Tax Benefit	—	—	—	(55,000)
Net Income (Loss)	2,965,097	(96,546,698)	18,978,573	218,292,263
Net Income (Loss) Per Common Share – Basic	0.05	(0.49)	0.06	0.58
Net Income (Loss) Per Common Share – Diluted	0.05	(0.49)	0.06	0.58

	Quarter Ended			
	March 31,	**June 30,**	**September 30,**	**December 31,**
2017				
Total Revenues	$ 65,816,847	$ 64,901,882	$ 41,598,659	$ 37,002,281
Gain (Loss) on Derivative	16,960,883	16,513,032	(12,663,253)	(35,477,317)

Instruments, Net				
Total Operating Expenses	32,572,699	34,576,905	41,013,678	40,661,791
Income (Loss) from Operations	33,244,148	30,324,977	584,981	(3,659,510)
Other Income (Expense)	(16,303,805)	(16,523,118)	(16,672,448)	(21,759,013)
Income Tax Benefit	—	—	—	(1,570,016)
Net Income (Loss)	16,940,523	13,801,859	(16,087,467)	(23,848,687)
Net Income (Loss) Per Common Share – Basic	0.28	0.22	(0.26)	(0.37)
Net Income (Loss) Per Common Share – Diluted	0.27	0.22	(0.26)	(0.37)