NORTHERN OIL & GAS, INC.
Form 10-Q
May 07, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2018

¨ 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)

Minnesota	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)
(952) 476-9800
(Registrant's Telephone Number)
N/A
(Former name, former address and former fiscal year, if changed since last report)

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 x No ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or 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 ¨ (Do not check if a smaller reporting company)

Emerging Growth Company ¨	Smaller Reporting 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 x

As of May 1, 2018, there were 128,187,856 shares of our common stock, par value $0.001, outstanding.

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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.

Terms used to describe quantities of crude oil and natural gas:

"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.

Terms used to describe our interests in wells and acreage:

"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.

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“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.

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“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.

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"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.

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NORTHERN OIL AND GAS, INC.
FORM 10-Q

March 31, 2018

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PART I - FINANCIAL INFORMATION
Item 1. Condensed Financial Statements.
NORTHERN OIL AND GAS, INC.
CONDENSED BALANCE SHEETS
MARCH 31, 2018 AND DECEMBER 31, 2017

	March 31, 2018 (unaudited)	December 31, 2017
ASSETS		
Current Assets:		
Cash and Cash Equivalents	$89,472,745	$102,183,191
Accounts Receivable, Net	51,284,262	46,851,682
Advances to Operators	3,023,851	604,977
Prepaid and Other Expenses	2,454,565	2,333,288
Income Tax Receivable	785,016	785,016
Total Current Assets	147,020,439	152,758,154
Property and Equipment:		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	2,641,517,632	2,585,490,133
Unproved	1,578,767	1,699,344
Other Property and Equipment	1,003,388	981,303
Total Property and Equipment	2,644,099,787	2,588,170,780
Less – Accumulated Depreciation, Depletion and Impairment	(2,133,433,050)	(2,114,951,189)
Total Property and Equipment, Net	510,666,737	473,219,591
Deferred Income Taxes (Note 9)	785,000	785,000
Other Noncurrent Assets, Net	5,998,270	5,490,934
Total Assets	$664,470,446	$632,253,679
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current Liabilities:		
Accounts Payable	$95,148,543	$93,152,297
Accrued Expenses	6,607,642	6,339,425
Accrued Interest	18,839,931	4,836,112
Derivative Instruments	26,796,245	18,681,891
Asset Retirement Obligations	550,443	565,521
Total Current Liabilities	147,942,804	123,575,246
Long-term Debt, Net	980,782,714	979,324,222
Derivative Instruments	15,523,889	11,496,929
Asset Retirement Obligations	8,869,762	8,562,607
Other Noncurrent Liabilities	127,761	135,225
Total Liabilities	$1,153,246,930	$1,123,094,229
Commitments and Contingencies (Note 8)		
STOCKHOLDERS' DEFICIT		

Preferred Stock, Par Value $.001; 5,000,000 Authorized, No Shares Outstanding	—	—
Common Stock, Par Value $.001; 142,500,000 Authorized (3/31/2018 – 65,937,945 Shares Outstanding and 12/31/2017 – 66,791,633 Shares Outstanding)	65,938	66,792
Additional Paid-In Capital	448,766,213	449,666,390
Retained Deficit	(937,608,635)	(940,573,732)
Total Stockholders’ Deficit	(488,776,484)	(490,840,550)
TOTAL LIABILITIES AND STOCKHOLDERS’ DEFICIT	$664,470,446	$632,253,679

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

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NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF OPERATIONS
FOR THE THREE MONTHS ENDED MARCH 31, 2018 AND 2017
(UNAUDITED)

	Three Months Ended March 31,	
	2018	2017
REVENUES		
Oil, Natural Gas, and NGL Sales	$86,880,814	$48,848,222
Gain (Loss) on Derivative Instruments, Net	(20,271,451)	16,960,883
Other Revenue	4,100	7,742
Total Revenues	66,613,463	65,816,847
OPERATING EXPENSES		
Production Expenses	12,488,422	11,674,348
Production Taxes	7,922,314	4,461,265
General and Administrative Expenses	1,666,875	3,608,943
Depletion, Depreciation, Amortization and Accretion	18,630,629	12,828,143
Total Operating Expenses	40,708,240	32,572,699
INCOME FROM OPERATIONS	25,905,223	33,244,148
OTHER INCOME (EXPENSE)		
Interest Expense, Net of Capitalization	(23,106,761)	(16,303,805)
Other Income	166,635	180
Total Other Income (Expense)	(22,940,126)	(16,303,625)
INCOME BEFORE INCOME TAXES	2,965,097	16,940,523
INCOME TAX PROVISION (BENEFIT)	—	—
NET INCOME	$2,965,097	$16,940,523
Net Income Per Common Share – Basic	$0.05	$0.28
Net Income Per Common Share – Diluted	$0.05	$0.27
Weighted Average Shares Outstanding – Basic	65,215,148	61,446,156
Weighted Average Shares Outstanding – Diluted	65,382,772	61,972,123

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

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NORTHERN OIL AND GAS, INC.
CONDENSED STATEMENTS OF CASH FLOWS
FOR THE THREE MONTHS ENDED MARCH 31, 2018 AND 2017
(UNAUDITED)

	Three Months Ended March 31,	
	2018	2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$2,965,097	$16,940,523
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depletion, Depreciation, Amortization and Accretion	18,630,629	12,828,143
Amortization of Debt Issuance Costs	1,362,768	943,407
Amortization/Accretion of 8% Senior Notes Premium/Discount	117,183	117,183
Deferred Income Taxes	—	—
(Gain) Loss on the Mark-to-Market of Derivative Instruments	12,141,314	(17,056,542)
Share-Based Compensation Expense	(819,595)	613,578
Other	(39,976)	118,976
Changes in Working Capital and Other Items:		
Accounts Receivable, Net	(4,337,895)	1,894,975
Prepaid and Other Expenses	(723,297)	(888,188)
Accounts Payable	1,889,569	1,639,046
Accrued Interest	13,981,122	13,948,257
Accrued Expenses	353,758	(1,382,976)
Net Cash Provided by Operating Activities	45,520,677	29,716,382
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of Oil and Natural Gas Properties and Development Capital Expenditures, Net	(57,999,427)	(20,271,464)
Purchases of Other Property and Equipment	(22,085)	—
Net Cash Used for Investing Activities	(58,021,512)	(20,271,464)
CASH FLOWS FROM FINANCING ACTIVITIES		
Repayments on Revolving Credit Facility	—	(10,000,000)
Debt Issuance Costs Paid	(21,459)	—
Repurchase of Common Stock – Tax Obligations	(188,152)	(412,217)
Net Cash Used for Financing Activities	(209,611)	(10,412,217)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(12,710,446)	(967,299)
CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	102,183,191	6,486,098
CASH AND CASH EQUIVALENTS – END OF PERIOD	$89,472,745	$5,518,799
Supplemental Disclosure of Cash Flow Information		
Cash Paid During the Period for Interest	$7,630,556	$1,280,711
Cash Paid During the Period for Income Taxes	$—	$—
Non-Cash Financing and Investing Activities:		
Oil and Natural Gas Properties Included in Accounts Payable	$85,068,138	$57,107,728
Capitalized Asset Retirement Obligations	$184,305	$127,437
Non-Cash Compensation Capitalized on Oil and Gas Properties	$53,686	$74,395

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

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NOTES TO CONDENSED FINANCIAL STATEMENTS
MARCH 31, 2018
(UNAUDITED)

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Northern Oil and Gas, Inc. (the "Company," "Northern," "our" and words of similar import), a Minnesota 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. As of March 31, 2018, approximately 89% of Northern's 142,075 total net acres were developed.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

The financial information included herein is unaudited, except for the balance sheet as of December 31, 2017, which has been derived from the Company's audited financial statements for the year ended December 31, 2017. However, such information includes all adjustments (consisting of normal recurring adjustments and change in accounting principles) that are, in the opinion of management, necessary for a fair presentation of financial position, results of operations and cash flows for the interim periods. The results of operations for interim periods are not necessarily indicative of the results to be expected for an entire year.

Certain information, accounting policies, and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") have been condensed or omitted in this Form 10-Q pursuant to certain rules and regulations of the Securities and Exchange Commission ("SEC"). The condensed financial statements should be read in conjunction with the audited financial statements for the year ended December 31, 2017, which were included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

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 reserve volumes, future development costs, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, impairment of oil and natural gas properties, and deferred income taxes. Actual results may differ from those estimates.

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 and money market funds. The Company's cash positions represent assets held in checking and money market accounts. These assets 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 customer balances. Accounts receivable not expected to be collected within the next twelve months are included within Other Noncurrent Assets, Net on the condensed balance sheets.

As of March 31, 2018 and December 31, 2017, the Company included accounts receivable of $5.4 million and $5.5 million, respectively, in Other Noncurrent Assets, Net due to their long-term nature.

The allowance for doubtful accounts at March 31, 2018 and December 31, 2017 was $5.2 million and $5.6 million, respectively.

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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 $35,517 and $44,474 for the three months ended March 31, 2018 and 2017, 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 the 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 three months ended March 31, 2018 and 2017, respectively.

	Three Months Ended March 31,	
	2018	2017
Capitalized Certain Payroll and Other Internal Costs	$170,850	$204,873
Capitalized Interest Costs	35,065	38,768
Total	$205,915	$243,641

As of March 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 three months ended March 31, 2018 and 2017, 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.

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The Company did not have any ceiling test impairment for the three months ended March 31, 2018 and 2017. Impairment charges affect the Company's reported net income but do not reduce the Company's cash flow. If a significantly lower pricing environment reoccurs, the Company expects it could be required to further writedown the value of its oil and natural gas properties. In addition to commodity prices, the Company's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine the Company's actual ceiling test calculation and impairment analyses in future periods.

Capitalized costs associated with impaired 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 three months ended March 31, 2018 and 2017, the Company expired leases of $3.8 million in each period.

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. 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.

Debt Issuance Costs

Debt issuance costs include origination, legal and other fees to issue debt in connection with the Company's term loan credit agreement, senior unsecured notes and prior revolving credit facility. 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 three months ended March 31, 2018 and 2017 was $1.4 million and $0.9 million, respectively.

Bond Premium/Discount on Senior Notes

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 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 for the three months ended March 31, 2018 and 2017 was $0.4 million in each period.

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 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 discount for the three months ended March 31, 2018 and 2017 was $0.5 million in each period.

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.

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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. However, under these contracts, the natural gas may be sold to a single purchaser or may be sold to separate purchasers. 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 three months ended March 31, 2018 and 2017, 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 three months ended March 31, 2018 and 2017 were $79.1 million and $44.3 million, respectively. Natural gas and NGL sales for the three months ended March 31, 2018 and 2017 were $7.7 million and $4.5 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 from purchasers of its crude oil and natural gas production. While certain of these customers 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 has been and will continue to be immaterial to the Company's results of operations over the long-term.

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.

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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.

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 March 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. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas and a variety of additional factors that are beyond the Company's control. 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 March 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 March 31, 2018 and December 31, 2017 was $226.2

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.

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The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three months ended March 31, 2018 and 2017 are as follows:

	Three Months Ended March 31,	
	2018	2017
Weighted Average Common Shares Outstanding – Basic	65,215,148	61,446,156
Plus: Potentially Dilutive Common Shares Including Stock Options and Restricted Stock	167,624	525,967
Weighted Average Common Shares Outstanding – Diluted	65,382,772	61,972,123
Restricted Stock and Stock Options Excluded From EPS Due To The Anti-Dilutive Effect	67,026	124,018

As of March 31, 2018 and 2017, potentially dilutive shares from stock option awards were 250,000 and 391,872, respectively. These options were all exercisable at March 31, 2018 and 2017. The Company also has potentially dilutive shares from restricted stock awards outstanding of 639,824 and 1,837,822 at March 31, 2018 and 2017, 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 in 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 condensed statements of operations. See Note 11 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. Crude 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 three months ended March 31, 2018 and 2017.

New Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board (“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

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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 follows 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 Company has completed the process of evaluating the effect of the adoption and determined there were no changes required to our reported revenues as a result of the adoption. The majority of our revenue arrangements generally consist of a single performance obligation to transfer promised goods or services. Based on our evaluation process and review of our contracts with customers, the timing and amount of revenue recognized based on the standard is consistent with our 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 implemented processes and controls to ensure new contracts are reviewed for the appropriate accounting treatment and to generate the disclosures required under the new standard in the first quarter of 2018. We have determined the adoption of the standard will not have a material impact on our results of operations, cash flows, or financial position.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). 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 new guidance is effective for annual and interim reporting periods beginning after December 15, 2018. The amendments should be applied at the beginning of the earliest period presented using a modified retrospective approach with earlier application permitted as of the beginning of an interim or annual reporting period. The Company is currently evaluating the impact of the new guidance on its financial statements, however, based on its current operating leases, it is not expected to have a material impact.

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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 condensed statements of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets 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 March 31, 2018 and December 31, 2017 were approximately $85.1 million and $85.0 million, respectively.

Acquisitions

For the three months ended March 31, 2018, the Company acquired approximately 1,176 net acres, for an average cost of approximately $1,787 per net acre, in its key prospect areas in the form of effective leases.

For the three months ended March 31, 2017, the Company acquired approximately 371 net acres, for an average cost of approximately $607 per net acre, in its key prospect areas in the form of effective leases.

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.

The Company historically has acquired its properties by purchasing individual or small groups of leases directly from mineral owners or from 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.

Unproved properties not being amortized comprise approximately 13,229 net acres and 14,377 net acres of undeveloped leasehold interests at March 31, 2018 and December 31, 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.

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 three months ended March 31, 2018 and 2017, the Company included $0.1 million and $0.1 million, respectively, related to expiring leases within costs subject to the depletion calculation.

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NOTE 4 LONG-TERM DEBT

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

	March 31, 2018			
	Principal Balance	Unamortized Net Discount	Debt Issuance Costs, Net	Long-term Debt, Net
8% Senior Notes	$700,000,000	$(1,080,771)	$(6,139,189)	692,780,040
Term Loan Credit Agreement	300,000,000	—	(11,997,326)	288,002,674
Total	$1,000,000,000	$(1,080,771)	$(18,136,515)	$980,782,714

	December 31, 2017			
	Principal Balance	Unamortized Net Discount	Debt Issuance Costs, Net	Long-term Debt, Net
8% Senior Notes	$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

Term Loan Credit Agreement

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 provides for the issuance of an aggregate principal amount of up to $500,000,000 in term loans to the Company, consisting of (i) $300,000,000 in initial term loans that were made on the Effective Date (the "Initial Loans"), (ii) $100,000,000 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 $100,000,000 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 may not be reborrowed. The term loan facility provided by the term loan credit agreement matures on November 1, 2022.

Borrowings under the term loan credit agreement bear 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" is 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 shall bear interest at a rate equal to 3.00% per annum plus the then-effective rate of interest. Interest is payable on the last business day of each March, June, September and December.

A commitment fee will be paid on the unused amount of the delayed draw commitments based on an annual rate of 2.00% (the "Commitment Fee"). The term loan credit agreement also requires the Company to prepay the loans with 100.00% of the net cash proceeds received from certain asset sales, swap terminations, incurrences of borrowed money indebtedness, equity issuances, casualty events and extraordinary receipts, subject to certain exceptions and specified reinvestment rights. 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 within one year of the funding of the applicable Loan that allows the lenders to attain approximately the same yield as if such Loan remained outstanding for the entire 1-year period plus a call protection amount equal to the product of the principal amount of Loans so prepaid, terminated, refinanced, reduced or accelerated multiplied by 7.00%; for any such prepayment, termination, refinancing, reduction or acceleration occurring on or after the one-year anniversary of the funding of the applicable Loan, a call protection amount equal to the product of the principal amount of Loans so prepaid, terminated, refinanced, reduced or accelerated multiplied by (i) 7.00% if occurring within 18 months of the funding of such Loan, (ii) 3.00% if occurring after the 18-month anniversary but on or prior to the 30-month anniversary of the funding of such Loan, or (iii) 1.00% if occurring after the 30-month anniversary but on or prior to the 42-month anniversary of the funding of such Loan, will be due, 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 term loan credit agreement contains 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 our business or operations, merge, consolidate, or make certain types of investments and require the outstanding principal amount of the Company's 8.00% senior unsecured notes due 2020 to be no more than $30 million by March 1, 2020. In addition, the term loan credit agreement requires that the Company comply with the following financial covenants: (i) as of any date of determination, the ratio of Total PDP PV-10 (as defined in the term loan credit agreement) plus the aggregate amount of all unrestricted cash and cash equivalents (in accounts subject to control agreements) to the amount of Senior Secured Debt (as defined in the term loan credit agreement) shall not be less than 1.30 to 1.00, (ii) as of the last day of any fiscal quarter, the ratio of Net Senior Secured Debt (as defined in the term loan credit agreement) to EBITDAX (as defined in the term loan credit agreement) for the period of four fiscal quarters then ending on such day will not be greater than 3.75 to 1.00 and (iii) as of any date of determination the Company's unrestricted cash and cash equivalents (in accounts subject to control agreements) plus the aggregate undrawn delayed draw commitments available to the Company shall not be less than $20.0 million.

The obligations of the Company under the term loan credit agreement may be accelerated upon the occurrence of an Event of Default (as defined in the term loan credit agreement). 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 the Company or its subsidiaries, bankruptcy or related defaults, defaults related to judgments and the occurrence of a Change in Control (as defined in the term loan credit agreement).

The Company's obligations under the term loan credit agreement are secured by mortgages on substantially all of the oil and gas properties of the Company subject to the limitations set forth in the 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 are secured by a first-priority security interest in substantially all of the assets of the Company.

8.000% Senior Notes Due 2020

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 (including repayment of borrowings that were outstanding under the Revolving Credit Facility at the time the Notes were issued).

Since June 1, 2017, the Company has been authorized to redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 102% plus accrued and unpaid interest to the redemption date. Beginning on June 1, 2018, the applicable redemption price will equal the principal amount, plus accrued and unpaid interest to the redemption date.

The Original Notes and the 2013 Follow-on Notes are 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 are 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. As such, the Mirror Indenture, together with the Original Indenture, are referred to herein as the "Indenture."

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The Indenture restricts the Company's ability to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or, repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and the Company and its subsidiaries (if any) will cease to be subject to such covenants.

The Indenture contains customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal of or premium, if any, on any Note when due;
- failure by the Company to comply with its other obligations under the Indenture, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of the Company and certain of its subsidiaries, if any, in the aggregate principal amount of $25.0 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary;
- failure by the Company or any significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary to pay certain final judgments aggregating in excess of $25.0 million within 60 days; and
- any guarantee of the Notes by a guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

Exchange Agreement

On January 31, 2018, the Company entered into an exchange agreement that was subsequently amended on each of March 20, 2018 and April 2, 2018 (as amended, the "Exchange Agreement") with holders (the "Supporting Noteholders") of approximately $497.0 million, or 71%, of the aggregate principal amount of the Company's outstanding 8.000% senior unsecured notes due 2020 (the "Outstanding Notes"), pursuant to which the Supporting Noteholders have agreed to exchange all of the Outstanding Notes held by each such Supporting Noteholder for approximately $155.0 million of the Company's common stock, par value $0.001 (the "Common Stock"), and approximately $344.0 million in aggregate principal amount of new senior secured second lien notes due 2023 (the "Second Lien Notes") (such proposed exchange, the "Exchange Transaction").

The obligations of the Supporting Noteholders under the Exchange Agreement, including their obligation to exchange their Outstanding Notes, are subject to the conditions set forth in the Exchange Agreement, including: (a) the Company raises at least $140.0 million in gross cash proceeds from the sale of its common stock (the "Equity Raise"); (b) the Company reincorporates in the State of Delaware; (c) the Company receives shareholder approvals for the issuance of shares in connection with the Exchange Transaction; (d) the Company obtains the requisite consent of the lenders under its term loan credit agreement (including pursuant to an amendment to the terms thereof) to permit the Exchange Transaction; and (e) the agent under the term loan credit agreement and the trustee for the Second Lien Notes enter into a customary intercreditor agreement. The Exchange Agreement will terminate upon written notice of termination by us or the Supporting Noteholders if the Exchange Transaction has not closed on or before May 15, 2018.

The Exchange Agreement contains certain representations, warranties and other agreements by the Company and the Supporting Noteholders. The Company's and the Supporting Noteholders' obligations under the Exchange Agreement are subject to various customary conditions set forth in the Exchange Agreement, including the negotiation, execution and delivery of an indenture for the Second Lien Notes and other definitive documentation for the Exchange Transaction. Accordingly, there can be no assurance if or when the Company will consummate the Exchange Transaction and the other transactions contemplated by the Exchange Agreement. The Company will not receive any cash proceeds from the issuance of the Second Lien Notes or the Common Stock to be issued to the Supporting Noteholders pursuant to the Exchange Agreement.

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NOTE 5 COMMON AND PREFERRED STOCK

The Company's Amended and Restated Articles of Incorporation authorize the issuance of up to 147,500,000 shares. The shares are classified in two classes, consisting of 142,500,000 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 during the three months ended March 31, 2018 and the year ended December 31, 2017:

	Three Months Ended March 31, 2018	Year Ended December 31, 2017
Beginning Balance	66,791,633	63,259,781
Restricted Stock Grants (Note 6)	127,999	911,355
Legal Settlement	—	3,000,000
Other Surrenders - Tax Obligations	(89,601)	(270,510)
Other Forfeitures	(892,086)	(108,993)
Ending Balance	65,937,945	66,791,633

2018 Activity

During the three months ended March 31, 2018, 0.1 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 $0.2 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 Transaction

On January 31, 2018, the Company entered into the Exchange Agreement (see Note 4). If the Exchange Agreement is consummated, the Company would be required to issue approximately $155.0 million of the Company's common stock (the "Exchange Consideration") to the Supporting Noteholders as partial consideration for their exchange of the Outstanding Notes.

In addition, one of the conditions to closing of the Exchange Transaction is that the Company raise at least $140.0 million in gross cash proceeds from the sale of its common stock (the "Equity Raise"). During April 2018, to satisfy a portion of the Equity Raise requirement, the Company completed an underwritten public offering of common stock (the "Public Offering") pursuant to which it has issued 62.3 million shares of common stock and received gross proceeds of $93.4 million (see Note 12). In addition, during the three months ended March 31, 2018, the Company and various investors entered into subscription agreements (the "Subscription Agreements") whereby such investors agreed to purchase up to $52.0 million of the Company's common stock, subject to the closing of the Exchange Agreement.

The shares of common stock to be issued as Exchange Consideration and pursuant to the Subscription Agreements are expected to be valued at the public offering price of the shares issued in the Public Offering, which was $1.50 per share. As a result, in addition to the 62.3 million shares of common stock issued in April 2018 pursuant to the Public Offering, upon closing of the Exchange Transaction, the Company would be required to issue an additional approximately 103.2 million shares of our common stock as Exchange Consideration, and up to an additional approximately 34.7 million shares of our common stock pursuant to the Subscription Agreements.

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Acquisition Agreement

On April 25, 2018, the Company entered into a definitive agreement with Salt Creek Oil and Gas, LLC to acquire oil and gas properties, subject to typical closing conditions. The transaction is expected to close in early June 2018, and the consideration payable by the Company upon closing would include the issuance of 6 million shares of the Company's common stock.

Stock Repurchase Program

In May 2011, the Company's board of directors approved a stock repurchase program to acquire up to $150 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.

During the three months ended March 31, 2018 and March 31, 2017, the Company did not repurchase shares of its common stock under the stock repurchase program. The Company's accounting policy upon the repurchase of shares is to deduct its par value from Common Stock and to reflect any excess of cost over par value as a deduction from Additional Paid-in Capital.

NOTE 6 STOCK OPTIONS/STOCK-BASED COMPENSATION AND WARRANTS

The Company maintains its 2013 Incentive Plan (the "2013 Plan") 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 March 31, 2018, there were 3,742,035 shares available for future awards under the 2013 Plan.

Restricted Stock Awards

During the three months ended March 31, 2018, the Company issued 96,152 restricted shares of common stock under the 2013 Plan 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 March 2021. As of March 31, 2018, there was approximately $1.4 million of total unrecognized compensation expense related to unvested restricted stock that will be recognized over a weighted-average period of approximately 1.8 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 and activity related thereto for the three months ended March 31, 2018:

	Three Months Ended March 31, 2018	
	Number of Shares	Weighted-Average Price
Restricted Stock Awards:		
Restricted Shares Outstanding at Beginning of Period	1,721,533	$ 3.65
Shares Granted	96,152	2.08
Lapse of Restrictions	(285,775)	3.70
Shares Forfeited	(892,086)	4.00
Restricted Shares Outstanding at End of Period	639,824	$ 2.89

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Stock Option Awards

The following table reflects the outstanding stock option awards and the activity related thereto for the three months ended March 31, 2018:

	Stock Option Awards (1)	Weighted-Average Exercise Price	Weighted Average Contractual Term
Outstanding as of 12/31/2017	250,000	$ 2.79	1.0
Granted	—	—	
Exercised	—	—	
Expired or canceled	—	—	
Forfeited	—	—	
Outstanding as of 3/31/2018	250,000	$ 2.79	0.7

(1) All of the stock options outstanding were vested and exercisable at the end of the period.

NOTE 7 RELATED PARTY TRANSACTIONS

Michael Frantz, a member of the Company’s board of directors since August 2016, is the Vice President, Investments of TRT Holdings, Inc. Michael Popejoy, a member of the Company’s board of directors since January 2017, is the Senior Vice President of Energy for TRT Holdings, Inc. TRT Holdings and its affiliates (collectively, “TRT”) are significant common stockholders of the Company and also a holder of the Company’s 8% senior unsecured notes, due 2020 (the “Notes”). The Company believes TRT owned in excess of $200 million aggregate principal amount of the Notes at March 31, 2018. The principal amounts of any Notes held by TRT are included in the Company’s long-term debt balances, and the Company’s interest expense includes interest attributable to any Notes held by TRT.

Exchange Agreement

On January 31, 2018, the Company entered into the Exchange Agreement, pursuant to which the Supporting Noteholders have agreed to exchange all of the Outstanding Notes held by each such Supporting Noteholder for approximately $155 million of the Company’s common stock and approximately $344 million in aggregate principal amount of Second Lien Notes. TRT Holdings, Inc. (“TRT”), Cresta Investments, LLC and Robert B. Rowling (together, the “TRT Noteholders”) are Supporting Noteholders and would receive, 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. 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 obligations of the Supporting Noteholders under the Exchange Agreement, including their obligation to exchange their Outstanding Notes, are subject to the conditions set forth in the Exchange Agreement, which are described in Note 4 above.

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, 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 $3.00 per share (subject to downward adjustment based on the pricing of the Equity Raise), subject to the closing of the Exchange Transaction. Pursuant to their respective Subscription Agreements, Mr. Akradi agreed to purchase $12.0 million of the Company’s common stock and TRT agreed to purchase $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 would purchase 8.0 million shares of the Company’s common stock and TRT would purchase 6.7 million shares of the Company’s common stock pursuant to their respective Subscription Agreements if the Exchange Transaction is completed. 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.

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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 the Company 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, the Company agreed that at the closing of the Exchange Transaction, it will enter into registration rights agreements with (i) the Supporting Noteholders, including the TRT Noteholders, pursuant to which the Company will agree 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) with the TRT Noteholders and an affiliate of TRT, pursuant to which the Company will agree 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 will receive pursuant to the Exchange Transaction.

All transactions involving related parties are approved or ratified by the Company's Audit Committee.

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 $5.4 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 $5.4 million in accounts receivable is included in "Other Noncurrent Assets, Net" on the condensed balance sheets. The Company fully maintains the validity of its interests in the crude oil and natural gas leases.

On August 18, 2016, plaintiff 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, Michael Reger (our former chief executive officer), and Thomas Stoelk (our former chief financial officer and interim chief executive officer) as defendants. An amended complaint was filed by plaintiffs in July 2017. Defendants (including the Company) filed a motion to dismiss the amended complaint in August 2017. The court granted the Company's motion to dismiss 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 complaint purports 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 seeks 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. The Company intends to continue to vigorously defend itself in this matter.

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NOTE 9 INCOME TAXES

The Company utilizes the asset and liability approach to measuring deferred tax assets and liabilities based on temporary differences existing at each balance sheet date using currently enacted tax rates. A valuation allowance for the Company's deferred tax assets is established if, in management's opinion, it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. At March 31, 2018, a valuation allowance of $226.2 million had been provided for our net deferred tax assets based on the uncertainty regarding whether these assets may be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

The income tax provision (benefit) for the three months ended March 31, 2018 and 2017 consists of the following:

	Three Months Ended March 31,	
	2018	2017
Current Income Tax Provision (Benefit)	$ —	$ —
Deferred Income Tax Provision (Benefit)		
Federal	620,000	5,950,000
State	137,000	536,000
Valuation Allowance	(757,000)	(6,486,000)
Total Income Tax Provision (Benefit)	$ —	$ —

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 year ended December 31, 2017 and for the quarter ended March 31, 2018 reflect certain effects of the Act which includes a reduction in the corporate tax rate from 35% to 21% effective January 1, 2018, as well as other changes.

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.

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.

Income tax provision (benefit) during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income (loss), plus any unusual or infrequently occurring items that are recorded in the interim period. The provision for the three-month periods ended March 31, 2018, presented above, differ from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to income before income taxes. The lower effective tax rate in 2018 and 2017 relates to the valuation allowance placed on the net deferred tax assets, in addition to state income taxes and estimated permanent differences.

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 three months ended March 31, 2018 and 2017, the Company did not recognize any interest or penalties in its condensed statements of operations, nor did it have any interest or penalties accrued in its condensed balance sheet at March 31, 2018 and December 31, 2017 relating to unrecognized benefits.
The tax years 2017, 2016 and 2015 remain open to examination for federal income tax purposes and tax years 2017, 2016, 2015, 2014, 2013, 2012, 2011 and 2010 by the other major taxing jurisdictions to which the Company is subject.

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NOTE 10 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:

	Fair Value Measurements at March 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 Asset (crude oil swaps)	$ —	$ —	$ —
Commodity Derivatives – Noncurrent Asset (crude oil swaps)	—	—	—
Commodity Derivatives – Current Liabilities (crude oil swaps)	—	(26,796,245)	—
Commodity Derivatives – Noncurrent Liabilities (crude oil swaps)		(15,523,889)	
Total	$ —	$ (42,320,134)	$ —

	Fair Value Measurements at December 31, 2017 Using		
	Quoted Prices In	Significant Other Observable	Significant Unobservable Inputs

	Active Markets for Identical Assets (Liabilities) (Level 1)	Inputs (Level 2)	(Level 3)
Commodity Derivatives – Current Asset (crude oil swaps)	$ —	$ —	$ —
Commodity Derivatives – Noncurrent Asset (crude oil swaps)	—	—	—
Commodity Derivatives – Current Liabilities (crude oil swaps)		(18,681,891)	
Commodity Derivatives – Noncurrent Liabilities (crude oil swaps)	—	(11,496,929)	—
Total	$ —	$ (30,178,820)	$ —

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The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include crude oil swaps, collars, and swaptions (see Note 11). 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 condensed balance sheet. The current derivative asset and liability amounts represent the fair values expected to be settled in the subsequent twelve months.

Fair Value of Other Financial Instruments

The Company's financial instruments, including certain cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments.

The carrying amount of the Company's long-term debt reported in the condensed balance sheet at March 31, 2018 is $980.8 million, which includes $692.8 million of senior unsecured notes and $288.0 million of borrowings under the Company's term loan credit agreement (see Note 4). The fair value of the Company's senior unsecured notes, which are publicly traded, is $642.0 million at March 31, 2018. The Company's term loan credit agreement 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 during the three months ended March 31, 2018 were approximately $0.2 million.

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 three months ended March 31, 2018.

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NOTE 11 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

The Company utilizes commodity swap contracts, 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 10). 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 condensed 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.

	Three Months Ended March 31,	
	2018	2017
Cash Received (Paid) on Settled Derivatives	$(8,130,137)	$(95,659)
Non-Cash Mark-to-Market Gain (Loss) on Derivatives	(12,141,314)	17,056,542
Gain (Loss) on Derivative Instruments, Net	$(20,271,451)	$16,960,883

The Company has master netting agreements on individual crude oil 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.

The following table reflects open commodity swap contracts as of March 31, 2018, the associated volumes and the corresponding fixed price.

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Settlement Period	Oil (Barrels)	Fixed Price ($)
Swaps-Crude Oil		
04/01/18 – 08/31/18	100,000	49.99
04/01/18 – 08/31/18	100,000	50.04
04/01/18 – 08/31/18	100,000	49.99
04/01/18 – 08/31/18	100,000	50.17
04/01/18 – 09/30/18	180,000	53.99
04/01/18 – 09/30/18	180,000	53.99
04/01/18 – 09/30/18	183,000	55.19
04/01/18 – 12/31/18	135,000	53.30
04/01/18 – 12/31/18	275,000	54.80
04/01/18 – 12/31/18	275,000	54.09
04/01/18 – 12/31/18	275,000	54.42
10/01/18 – 12/31/18	92,000	52.50
10/01/18 – 12/31/18	92,000	52.55
10/01/18 – 12/31/18	46,000	54.50
10/01/18 – 12/31/18	92,000	52.50
01/01/19 – 03/31/19	45,000	54.22
01/01/19 – 03/31/19	63,000	53.65
01/01/19 – 12/31/19	365,000	51.05
01/01/19 – 12/31/19	365,000	51.05
01/01/19 – 12/31/19	182,500	52.70
01/01/19 – 12/31/19	365,000	51.05
01/01/19 – 12/31/19	182,500	52.15
01/01/19 – 12/31/19	182,500	52.75
01/01/19 – 12/31/19	219,000	57.30
01/01/19 – 06/30/19	108,600	57.90
04/01/19 – 06/30/19	45,500	53.59
04/01/19 – 06/30/19	36,400	53.10
07/01/19 – 09/30/19	46,000	53.07
07/01/19 – 09/30/19	9,200	52.65
01/01/20 – 03/31/20	27,300	51.81
01/01/20 – 03/31/20	45,500	54.05
01/01/20 – 03/31/20	45,500	54.25
01/01/20 – 03/31/20	27,300	54.65
01/01/20 – 12/31/20	366,000	49.77
01/01/20 – 12/31/20	183,000	51.30
01/01/20 – 12/31/20	109,800	51.70
01/01/20 – 12/31/20	366,000	49.75
01/01/20 – 12/31/20	183,000	51.10
04/01/20 – 06/30/20	9,100	51.50
04/01/20 – 06/30/20	9,100	54.70
01/01/21 – 03/31/21	90,000	52.50
01/01/21 – 03/31/21	90,000	53.00
01/01/21 – 03/31/21	90,000	52.55
01/01/21 – 03/31/21	18,000	53.20

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As of March 31, 2018, the Company had a total volume on open commodity swaps of 6.1 million barrels at a weighted average price of approximately $52.48 per barrel.

The following table reflects the weighted average price of open commodity swap derivative contracts as of March 31, 2018, by year with associated volumes.

Year	Volumes (Bbl)	Weighted Average Price ($)
2018	2,225,000	53.33
2019	2,215,200	52.64
2020	1,371,600	50.77
2021 and beyond	288,000	52.72

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at March 31, 2018 and December 31, 2017, respectively. Certain amounts may be presented on a net basis on the condensed financial statements when such amounts are with the same counterparty and subject to a master netting arrangement.

Type of Crude Oil Contract	Balance Sheet Location	March 31, 2018 Estimated Fair Value	December 31, 2017 Estimated Fair Value
Derivative Liabilities:			
Swap Contracts	Current Liabilities	$(26,796,245)	$(18,681,891)
Swap Contracts	Noncurrent Liabilities	(15,523,889)	(11,496,929)
Total Derivative Liabilities		$(42,320,134)	$(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 March 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:			
Current Assets	$—	$ —	$—
Noncurrent Assets	—	—	—
Total Derivative Assets	$—	$ —	$—
Offsetting of Derivative Liabilities:			
Current Liabilities	$(26,796,245)	$ —	$(26,796,245)

Noncurrent Liabilities	(15,530,627)	6,738	(15,523,889)
Total Derivative Liabilities	$(42,326,872)	$ 6,738	$(42,320,134)

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	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	$—	$ —	$—
Non-Current Assets	—	—	—
Total Derivative Assets	$—	$ —	$—
Offsetting of Derivative Liabilities:			
Current Liabilities	$(18,681,891)	$ —	$(18,681,891)
Non-Current 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 BP Energy Company, Macquarie Bank Limited, and Fifth Third Bank. The Company's obligations under the derivative instruments are secured pursuant to the term loan credit agreement and related agreements, and no additional collateral had been posted by the Company as of March 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 10 for the aggregate fair value of all derivative instruments that were in a net liability position at March 31, 2018 and December 31, 2017.

NOTE 12 SUBSEQUENT EVENT

On April 10, 2018, the Company completed an underwritten public offering (the "Offering"), whereby the Company sold 58,666,667 shares of the Company's common stock at a public offering price of $1.50 per share. The underwriters have a 30-day option to purchase up to an additional 8,800,000 shares of common stock from us at the public offering price, less the underwriting discount, which they partially exercised on April 16, 2018 by purchasing an additional 3,592,684 shares. The Company has received gross proceeds of $93.4 million and net proceeds of approximately $89.5 million, net of underwriting discounts and estimated offering expenses. The amount raised through the Offering satisfied a portion of the Company's obligation to complete the Equity Raise pursuant to the Exchange Agreement, as described in Note 4 above.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Cautionary Statement Concerning Forward-Looking Statements

This Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements regarding future events and our future results that are subject to the safe harbors created under the Securities Act of 1933 (the "Securities Act") and the Securities Exchange Act of 1934 (the "Exchange Act"). 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," "anticipate," "target," "intend," "seek," "goal," "will," "should," "may" or other words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about actual or potential future sales, market size, collaborations, 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 consummate any transaction with our bondholders, including the final terms of any such transaction, which could result in the issuance of a significant amount of equity, our ability to raise or access capital, including as a condition to any transaction with our bondholders, 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 achieved may differ materially from expected results described in these statements. You should consider carefully the statements in the section entitled "Item 1A. Risk Factors" and other sections of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017, as updated by subsequent reports we file with the SEC (including this report), which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Forward-looking statements speak only as of the date they are made. 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.

The following discussion should be read in conjunction with the unaudited Condensed Financial Statements and accompanying Notes to condensed Financial Statements appearing elsewhere in this report.

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 will provide drilling and development opportunities that 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 3,353 gross (234.7 net) producing wells as of March 31, 2018.

Our average daily production in the first quarter of 2018 was approximately 17,995 Boe per day, of which approximately 84% was oil. Improving commodity prices in 2018 has increased activity levels in North Dakota as compared to 2017 with 62 active rigs in North Dakota as of April 24, 2018. The higher activity levels have boosted our development levels and resulted in production in the first quarter of 2018 increasing by approximately 35% over the same period a year ago. During the three months ended March 31, 2018, we participated in the drilling of 91 gross (5.8 net) wells that were completed and added to production. As of March 31, 2018, we leased approximately 142,075 net acres, of which 100% were located in the Williston Basin of North Dakota and Montana.

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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, barge, 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 market-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.

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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 such as St. James, Louisiana, which offers prices benchmarked to Brent/LLS. 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 the first quarter of 2018 was $4.46 per barrel, as compared to $8.06 per barrel in the first quarter of 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 have increased our drilling activity in the Williston Basin in the first quarter of 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. As a result, we expect our average costs from wells we elect to participate in to increase 5-10% during 2018. During the first three months of

2018, the weighted average authorization for expenditure (or AFE) cost for wells we elected to participate in was $7.9 million, compared to $7.5 million for the wells we elected to participate in during 2017.

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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 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, natural gas liquids ("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 three months ended March 31, 2018 and 2017.

	Three Months Ended March 31,	
	2018	2017
Average NYMEX Prices[(a)]		
Natural Gas (per Mcf)	$2.85	$3.06
Oil (per Bbl)	$62.89	$51.78

(a) Based on average NYMEX closing prices.

For the three months ended March 31, 2018, the average NYMEX pricing was $62.89 per barrel of oil or 21% higher than the average NYMEX price per barrel for the comparable period in 2017. Our realized oil price after reflecting settled derivatives was 20% higher in the first quarter of 2018 than in the first quarter of 2017 due to the higher NYMEX price per barrel and a lower oil price differential in 2018.

As of March 31, 2018, the Company had a total volume on open commodity swaps of 6.1 million barrels at a weighted average price of approximately $52.48 per barrel. The following table reflects the weighted average price of open commodity swap derivative contracts as of March 31, 2018, by year with associated volumes.

Year	Volumes (Bbl)	Weighted Average Price ($)
2018	2,225,000	53.33
2019	2,215,200	52.64
2020	1,371,600	50.77
2021 and beyond	288,000	52.72

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Results of Operations for the Three Months Ended March 31, 2018 and March 31, 2017

The following table sets forth selected operating data for the periods indicated.

	Three Months Ended March 31,		
	2018	2017	% Change
Net Production:			
Oil (Bbl)	1,354,602	1,014,095	34 %
Natural Gas and NGLs (Mcf)	1,589,514	1,096,971	45 %
Total (Boe)	1,619,521	1,196,924	35 %
Net Sales:			
Oil Sales	$79,143,313	$44,339,147	79 %
Natural Gas and NGL Sales	7,737,501	4,509,075	72 %
Gain (Loss) on Derivative Instruments, Net	(20,271,451)	16,960,883	(220)%
Other Revenue	4,100	7,742	(47)%
Total Revenues	66,613,463	65,816,847	1 %
Average Sales Prices:			
Oil (per Bbl)	$58.43	$43.72	34 %
Effect of Gain on Settled Derivatives on Average Price (per Bbl)	(6.00)	(0.09)	6,567 %
Oil Net of Settled Derivatives (per Bbl)	52.43	43.63	20 %
Natural Gas and NGLs (per Mcf)	4.87	4.11	19 %
Realized Price on a Boe Basis Including all Realized Derivative Settlements	48.63	40.73	19 %
Operating Expenses:			
Production Expenses	$12,488,422	$11,674,348	7 %
Production Taxes	7,922,314	4,461,265	78 %
General and Administrative Expense	1,666,875	3,608,943	(54)%
Depletion, Depreciation, Amortization and Accretion	18,630,629	12,828,143	45 %
Costs and Expenses (per Boe):			
Production Expenses	$7.71	$9.75	(21)%
Production Taxes	4.89	3.73	31 %
General and Administrative Expense	1.03	3.02	(66)%
Depletion, Depreciation, Amortization and Accretion	11.50	10.72	7 %
Net Producing Wells at Period End	234.7	214.6	9 %

Oil and Natural Gas Sales

In the first quarter of 2018, our oil, natural gas and NGL sales, excluding the effect of settled derivatives, increased 78% as compared to the first quarter of 2017, driven by a 32% increase in realized prices, excluding the effect of settled derivatives, and a 35% increase in production. The higher average realized price in the first quarter of 2018 as compared to the same period in 2017 was principally driven by higher average NYMEX oil and natural gas prices and a lower oil price differential. Oil price differential during the first quarter of 2018 was $4.46 per barrel, as compared to $8.06 per barrel in the first quarter of 2017.

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. Increased development and acquisition activities combined with improved performance from enhanced completions helped drive a 35% increase in production levels in the first quarter of 2018 compared to the same period in 2017.

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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 loss of $20.3 million in the first quarter of 2018, compared to a gain of $17.0 million in the first quarter of 2017. 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 the first quarter of 2018, we realized a loss on settled derivatives of $8.1 million, compared to a $0.1 million loss for the first quarter of 2017. The increase in the loss on settled derivatives was due to a larger spread between our average settlement price and the average NYMEX oil price in the first quarter of 2018 compared to the same period of 2017. During the first quarter of 2018, the derivative settlements included 0.9 million barrels of oil at an average settlement price of $53.42 per barrel as compared to the first quarter of 2017 which included 0.6 million barrels of oil at an average settlement price of $51.74 per barrel. The average NYMEX oil price for the first quarter of 2018 was $62.89 compared to $51.78 for the first quarter of 2017. Our average realized price (including all cash derivative settlements) in the first quarter of 2018 was $48.63 per Boe compared to $40.73 per Boe in the first quarter of 2017. The gain (loss) on settled derivatives decreased our average realized price per Boe by $5.02 in the first quarter of 2018 and decreased our average realized price per Boe by $0.08 in the first quarter of 2017.

Mark-to-market derivative gains and losses was a loss of $12.1 million in the first quarter of 2018, compared to a gain of $17.1 million in the first quarter of 2017. 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 are expected to be offset by lower wellhead revenues in the future, and any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At March 31, 2018, all of our derivative contracts were recorded at their fair value, which was a net liability of $42.3 million, an increase of $12.1 million from the $30.2 million net liability recorded as of December 31, 2017. The increase in the net liability at March 31, 2018 as compared to December 31, 2017 was primarily due to an increase in the forward oil price on our open oil derivative contracts relative to the contract price on our open oil derivative contracts since December 31, 2017.

Production Expenses

Production expenses were $12.5 million in the first quarter of 2018 compared to $11.7 million in the first quarter of 2017. On a per unit basis, production expenses decreased from $9.75 per Boe in the first quarter of 2017 to $7.71 per Boe in the first quarter of 2018. On an absolute dollar basis, the increase in our production expenses in the first quarter of 2018 as compared to the first quarter of 2017 was primarily due to a 35% increase in production, as well as a 9% increase in the total number of net producing wells, which was partially offset by lower processing and transportation costs.

Production Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were $7.9 million in the first quarter of 2018 compared to $4.5 million in the first quarter of 2017. The increase is due to higher commodity prices and higher production levels, which increased our oil and natural gas sales in the first quarter of 2018 as compared to the first quarter of 2017. As a percentage of oil and natural gas sales, our production taxes were 9.1% in both the first quarter of 2018 and 2017.

General and Administrative Expenses

General and administrative expenses were $1.7 million in the first quarter of 2018 compared to $3.6 million in the first quarter of 2017. The decrease was due to a $1.6 million reduction in compensation expense, primarily driven by reduced incentive compensation and a $1.2 million reversal of non-cash share based compensation expense in connection with the resignation of our former interim chief executive officer and chief financial officer. Additionally, legal and professional fees were $0.3 million lower in the first quarter of 2018 compared to the first quarter of 2017.

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Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion ("DD&A") was $18.6 million in the first quarter of 2018 compared to $12.8 million in the first quarter of 2017. Depletion expense, the largest component of DD&A, increased by $5.8 million in the first quarter of 2018 compared to the first quarter of 2017. The aggregate increase in depletion expense was driven by a 35% increase in production levels and an 8% increase in the depletion rate per Boe. On a per unit basis, depletion expense was $11.39 per Boe in the first quarter of 2018 compared to $10.58 per Boe in the first quarter of 2017. The higher depletion rate per Boe was primarily driven by increased well costs from higher intensity completion techniques, which was partially offset by an increase in our oil and natural gas reserves. Depreciation, amortization and accretion was $0.2 million in both the first quarter of 2018 and 2017. The following table summarizes DD&A expense per Boe for the first quarter of 2018 and 2017:

	Three Months Ended March 31,			
	2018	2017	Change	Change
Depletion	$11.39	$10.58	$0.81	8 %
Depreciation, Amortization and Accretion	0.11	0.14	(0.03)	(21)%
Total DD&A Expense	$11.50	$10.72	$0.78	7 %

Interest Expense

Interest expense, net of capitalized interest, was $23.1 million for the first quarter of 2018 compared to $16.3 million in the first quarter of 2017. The increase in interest expense for the first quarter of 2018 compared to the first quarter of 2017 was primarily due to higher levels of debt 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.

Income Tax Provision

During the first quarter of 2018 and 2017, no income tax expense (benefit) was recorded on the income (loss) before income taxes due to the valuation allowance placed on our net deferred tax asset because of the uncertainty regarding its realization. For further discussion of our valuation allowance, see Note 9 to our financial statements.

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Non-GAAP Financial Measures

We define Adjusted Net Income as net income (loss) excluding (gain) loss on the mark-to-market of derivative instruments, net of tax. Our Adjusted Net Income for the first quarter of 2018 was $11.3 million (representing approximately $0.17 per diluted share), compared to a loss of $0.1 million (representing approximately $0.00 per diluted share) for the first quarter of 2017. The increase in Adjusted Net Income is primarily due to higher commodity prices and significantly higher production levels, which were partially offset by higher production expenses.

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 and (v) non-cash share based compensation expense. Adjusted EBITDA for the first quarter of 2018 was $56.0 million, compared to Adjusted EBITDA of $29.6 million for the first quarter of 2017. The increase in Adjusted EBITDA is primarily due to significantly higher production levels and higher commodity prices, which were partially offset by higher production expenses.

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 expenses and unrealized commodity gains and losses 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 more closely reflect 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.

Adjusted Net Income and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to GAAP is included below:

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Reconciliation of Adjusted Net Income

	Three Months Ended March 31,	
	2018	2017
Net Income	$2,965,097	$16,940,523
Add:		
Impact of Selected Items:		
(Gain) Loss on the Mark-to-Market of Derivative Instruments	12,141,314	(17,056,542)
Selected Items, Before Income Taxes	12,141,314	(17,056,542)
Income Tax of Selected Items[(1)]	(3,853,035)	46,656
Selected Items, Net of Income Taxes	8,288,279	(17,009,886)
Adjusted Net Income (Loss)	$11,253,376	$(69,363)
Weighted Average Shares Outstanding – Basic	65,215,148	61,446,156
Weighted Average Shares Outstanding – Diluted	65,382,772	61,972,123
Net Income Per Common Share – Basic	$0.05	$0.28
Add:		
Impact of Selected Items, Net of Income Taxes	0.12	(0.28)
Adjusted Net Income (Loss) Per Common Share – Basic	$0.17	$—
Net Income Per Common Share – Diluted	$0.05	$0.27
Add:		
Impact of Selected Items, Net of Income Taxes	0.12	(0.27)
Adjusted Net Income (Loss) Per Common Share – Diluted	$0.17	$—

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(1) For the 2018 column, this represents a tax impact using an estimated tax rate of 25.5%, which includes a $0.8 million adjustment for a reduction in valuation allowance for the three months ended March 31, 2018. For the 2017 column, this represents a tax impact using an estimated tax rate of 38.3%, which includes a $6.5 million adjustment for a reduction in valuation allowance for the three months ended March 31, 2017.

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Reconciliation of Adjusted EBITDA

	Three Months Ended March 31,	
	2018	2017
Net Income	$2,965,097	$16,940,523
Add:		
Interest Expense	23,106,761	16,303,805
Income Tax Benefit	—	—
Depreciation, Depletion, Amortization and Accretion	18,630,629	12,828,143
Non-Cash Share Based Compensation	(885,845)	622,622
(Gain) Loss on the Mark-to-Market of Derivative Instruments	12,141,314	(17,056,542)
Adjusted EBITDA	$55,957,956	$29,638,551

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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 senior unsecured notes, 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% and 85% of our total production volumes in the first quarter of 2018 and 2017, respectively. 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 as required under our term loan credit agreement to partially mitigate volatility in the price of crude oil with respect to a portion of our expected oil production. In 2017, we hedged approximately 62% of our crude oil production and for the three months ended March 31, 2018, we hedged approximately 64% of our crude oil production.

The low commodity price environment of the last several years has adversely affected our business, financial position, results of operations and cash flow. During this time, we have taken steps to mitigate the effects of these lower prices, including: implementing cost savings initiatives, adjusting the Company's capital expenditure budget, reviewing possible divestitures, and other actions. In addition, in November 2017 we entered into a new term loan credit agreement with TPG Specialty Lending, Inc. and the lenders party thereto, which addressed the near-term maturity of our prior revolving credit facility and eliminated the potential degradation in liquidity caused by the previous facility's borrowing base re-determination feature. The term loan credit agreement has 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.

As of March 31, 2018, we had $300.0 million of borrowings on the term loan credit agreement, leaving $100.0 million of additional committed borrowing availability under the facility, as described in more detail below under "Term Loan Credit Facility." At March 31, 2018, we also had $700.0 million aggregate principal amount of outstanding 8.0% senior unsecured notes due June 1, 2020 (the "Notes"), as described below under "8.000% Senior Notes due 2020."

After the closing of the term loan credit facility in November 2017, we continued to focus on reducing our outstanding debt and extending our maturities while maintaining liquidity, as well as to analyze transactions in an effort to further mitigate the effects of depressed commodity prices. This included discussions and negotiations with certain holders (the "Supporting Noteholders") of approximately $497 million, or 71%, of the aggregate principal amount of our Notes (the "Outstanding Notes"). On January 31, 2018, we entered into an exchange agreement (that was subsequently amended on each of March 20, 2018 and April 2, 2018) with the Supporting Noteholders, pursuant to which the Supporting Noteholders have agreed to exchange all of the Outstanding Notes held by each such Supporting Noteholder for approximately $155 million of our common stock and approximately $344 million in aggregate principal amount of new senior secured second lien notes due 2023 (the "Second Lien Notes") (such proposed exchange, including the conditions thereto (including the Equity Raise (as defined below)), the "Exchange Transaction").

The consummation of the exchange agreement, and the obligations of the Supporting Noteholders to exchange their Outstanding Notes, are subject to the conditions set forth in the exchange agreement, including: (a) we raise at least $140 million in gross cash proceeds from the sale of our common stock (the "Equity Raise"); (b) we reincorporate in the State of Delaware; (c) we receive shareholder approvals for the issuance of shares in connection with the Exchange Transaction; (d) we obtain the requisite consent of the lenders under our term loan credit agreement (including pursuant to an amendment to the terms thereof) to permit the Exchange Transaction; and (e) the agent under the term loan credit agreement and the trustee for the Second Lien Notes enter into a customary intercreditor agreement.

The Exchange Transaction is intended to reduce our outstanding indebtedness, extend our maturities and strengthen our liquidity position. We are working to satisfy the conditions necessary to consummate the Exchange Transaction. Significantly, we believe we have effectively satisfied the Equity Raise requirement by virtue of (i) proceeds from our underwritten public offering of common stock completed in April 2018 (see Note 12), and (ii) expected proceeds from subscription agreements with certain parties (see Note 5), which are also contingent upon closing of the exchange agreement.

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With cash flow from operations coupled with our term loan credit agreement 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. Any significant acquisition of additional properties or significant increase in drilling activity may require us to seek additional capital. We may also choose to seek additional financing from the capital markets rather than utilize our existing liquidity sources to fund such activities. We cannot assure you, however, that any additional capital will be available to us on favorable terms or at all.

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 raise additional capital and/or maintain our desired levels of liquidity. At March 31, 2018, we had $980.8 million of total debt outstanding, $488.8 million of stockholders' deficit, and $89.5 million of cash on hand. Additionally, at March 31, 2018, there was $100.0 million of committed borrowing availability under our term loan credit agreement.

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 our term loan credit agreement covenant requirements. While we are currently in compliance with our financial covenants under the term loan credit agreement at March 31, 2018, there is no assurance we will be able to maintain compliance in the future.

In 2018, higher commodity prices have increased our development activities and caused our cash spend for development and acquisition activities to exceed our cash flow from operations by $12.5 million for the three months ended March 31, 2018. Rig activity levels in 2018 have increased from 2017 levels and nearly all of the wells utilize higher intensity completions. The improvements in per well productivity resulting from these newer completion techniques has caused us to increase our 2018 development spending compared to 2017.

Our recent capital commitments have been to fund drilling in the Williston Basin and, to a lesser extent, fund acreage acquisitions. We expect to fund our near-term capital requirements and working capital needs with cash on hand, cash flows from operations and available borrowing capacity under our term loan credit agreement. 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 March 31, 2018, we had a working capital deficit of $0.9 million, compared to a surplus of $29.2 million at December 31, 2017. Current assets decreased by $5.7 million and current liabilities increased by $24.4 million at March 31, 2018, compared to December 31, 2017. The decrease in current assets is primarily due to a lower cash balance as a result of our cash spend for development and acquisition activities, which exceeded our cash flow from operations by $12.5 million partially offset by higher accounts receivable due to higher commodity prices and production levels. The increase in current liabilities is primarily due to a $14.0 million increase in accrued interest on our senior notes because interest payments are due on June 1st and December 1st of each year, a $8.1 million increase in derivative instruments due to forward oil price changes, and a $2.0 million increase in accounts payable mainly attributable to an increase in our accrued drilling costs as a result of the growth of our in-process well inventory.

Cash Flows

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 the term loan credit agreement. As of March 31, 2018, we had entered into derivative swap contracts hedging 2.2 million barrels of oil for the remainder of 2018 at an average price of $53.33 per barrel, 2.2 million barrels of oil in 2019 at an average price of $52.64 per barrel, 1.4 million barrels of oil in 2020 at an average price of $50.77 per barrel, 0.3 million barrels of oil in 2021 at an average price of $52.72 per barrel.

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Our cash flows for the three months ended March 31, 2018 and 2017 are presented below:

	Three Months Ended March 31,	
	2018	2017
	(in thousands, unaudited)	
Net Cash Provided by Operating Activities	$45,521	$29,716
Net Cash Used for Investing Activities	(58,022)	(20,271)
Net Cash Provided by (Used for) Financing Activities	(210)	(10,412)
Net Change in Cash	$(12,710)	$(967)

Cash Flows from Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2018 was $45.5 million, compared to $29.7 million in the same period of the prior year. This increase was due to higher realized prices (including the effect of settled derivatives) and higher production levels, which was partially offset by higher interest costs. Net cash provided by operating activities is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our statements of cash flows) in the three months ended March 31, 2018 was an increase of $11.2 million compared to an increase of $15.2 million in the same period of the prior year.

Cash Flows from Investing Activities

Cash flows used in investing activities during the three months ended March 31, 2018 and 2017 was $58.0 million and $20.3 million, respectively. The increase in cash used in investing activities for the first three months of 2018 as compared to the same period of 2017 was attributable to higher development spending. Additionally, the amount of capital expenditures included in accounts payable (and thus not included in cash flows from investing activities) was $85.1 million and $57.1 million at March 31, 2018 and 2017, respectively, as a result of increased activity in the Williston Basin.

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 three months ended March 31, 2018, our capitalized costs incurred for oil and natural gas properties (e.g., drilling and completion costs and other capital expenditures) amounted to $55.9 million, while the actual cash spend in this regard amounted to $58.0 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 three months ended March 31, 2018 and 2017 are summarized in the following table:

	Three Months Ended March 31,	
	2018	2017
	(in millions, unaudited)	
Drilling and Completion Costs	$55.7	$19.7
Acreage and Related Activities	2.2	0.5

Other Capital Expenditures	0.1	0.1
Total	$58.0	$20.3

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Cash Flows from Financing Activities

Net cash used for financing activities was $0.2 million and $10.4 million during the three months ended March 31, 2018 and 2017, respectively. For the three months ended March 31, 2018, cash used for financing activities was primarily related to the remittance of taxes related to employee stock vestings. For the three months ended March 31, 2017, cash used for financing activities was primarily related to repayments of borrowings under our prior revolving credit facility. Our long-term debt at March 31, 2018 was $980.8 million, which was comprised of $692.8 million in senior unsecured notes and $288.0 million of borrowings under our term loan credit facility. As of March 31, 2018, we had $100.0 million of available borrowing capacity under our term loan credit facility.

Term Loan Credit Facility

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 provides for the issuance of an aggregate principal amount of up to $500 million in term loans to us, consisting of (i) $300 million in initial term loans that were made on the Effective Date (the “Initial Loans”), (ii) $100 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 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 may not be reborrowed. The term loan facility provided by the term loan credit agreement matures on November 1, 2022.

A portion of the proceeds from the Initial Loans were used on the Effective Date to repay in its entirety borrowings outstanding under our prior revolving credit facility.

Borrowings under the term loan credit agreement bear 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” is equal to the product of: (i) 3 month LIBOR multiplied by (ii) the statutory reserve rate. Upon the occurrence and continuance of an event of default all outstanding Loans shall bear interest at a rate equal to 3.00% per annum plus the then-effective rate of interest. Interest is payable on the last business day of each March, June, September and December.

A commitment fee is paid on the unused amount of the delayed draw commitments based on an annual rate of 2.00% (the “Commitment Fee”). The term loan credit agreement also requires us to prepay the loans with 100.00% of the net cash proceeds received from certain asset sales, swap terminations, incurrences of borrowed money indebtedness, equity issuances, casualty events and extraordinary receipts, subject to certain exceptions and specified reinvestment rights. 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 within one year of the funding of the applicable Loan that allows the lenders to attain approximately the same yield as if such Loan remained outstanding for the entire 1-year period plus a call protection amount equal to the product of the principal amount of Loans so prepaid, terminated, refinanced, reduced or accelerated multiplied by 7.00%; for any such prepayment, termination, refinancing, reduction or acceleration occurring on or after the one-year anniversary of the funding of the applicable Loan, a call protection amount equal to the product of the principal amount of Loans so prepaid, terminated, refinanced, reduced or accelerated multiplied by (i) 7.00% if occurring within 18 months of the funding of such Loan, (ii) 3.00% if occurring after the 18-month anniversary but on or prior to the 30-month anniversary of the funding of such Loan, or (iii) 1.00% if occurring after the 30-month anniversary but on or prior to the 42-month anniversary of the funding of such Loan, will be due, 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, we 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.

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The term loan credit agreement contains 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, or make certain types of investments and require the outstanding principal amount of our 8.00% senior unsecured notes due 2020 to be no more than $30 million by March 1, 2020. In addition, the term loan credit agreement requires that we comply with the following financial covenants: (i) as of any date of determination, the ratio of Total PDP PV-10 (as defined in the term loan credit agreement) plus the aggregate amount of all unrestricted cash and cash equivalents (in accounts subject to control agreements) to the amount of Senior Secured Debt (as defined in the term loan credit agreement) shall not be less than 1.30 to 1.00, (ii) as of the last day of any fiscal quarter, the ratio of Net Senior Secured Debt (as defined in the term loan credit agreement) to EBITDAX (as defined in the term loan credit agreement) for the period of four fiscal quarters then ending on such day will not be greater than 3.75 to 1.00 and (iii) as of any date of determination our unrestricted cash and cash equivalents (in accounts subject to control agreements) plus the aggregate undrawn delayed draw commitments available to us shall not be less than $20.0 million.

Our obligations under the term loan credit agreement may be accelerated upon the occurrence of an Event of Default (as defined in the term loan credit agreement). 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 on us or our subsidiaries, bankruptcy or related defaults, defaults related to judgments and the occurrence of a Change in Control (as defined in the term loan credit agreement).

Our obligations under the term loan credit agreement are secured by mortgages on substantially all of our oil and gas properties subject to the limitations set forth in the 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 are secured by a first-priority security interest in substantially all of our assets.

We were in compliance with our financial covenants under the term loan credit facility at March 31, 2018.

8.000% Senior Notes due 2020

On May 18, 2012, we 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, we 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, we 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 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 $185.0 million. Collectively, the net proceeds are in use to fund our exploration, development and acquisition program and for general corporate purposes (including repayment of borrowings that were outstanding under our prior revolving credit facility at the time the Notes were issued).

Since June 1, 2017, we have been authorized to redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 102% plus accrued and unpaid interest to the redemption date. Beginning on June 1, 2018, the applicable redemption price will equal the principal amount, plus accrued and unpaid interest to the redemption date.

The Original Notes and the 2013 Follow-on Notes are 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 are 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. As such, the Mirror Indenture, together with the Original Indenture, are referred to herein as the “Indenture.”

The Indenture restricts our ability to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase, equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and we and our subsidiaries (if any) will cease to be subject to such covenants.

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The Indenture contains customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal of or premium, if any, on any Note when due;
- failure by us to comply with our other obligations under the Indenture, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to our other indebtedness and certain of our subsidiaries, if any, in the aggregate principal amount of $25 million or more;
- certain events of bankruptcy, insolvency or reorganization of our company or a significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary;
- failure by us or any significant subsidiary or group of restricted subsidiaries that, taken together, would constitute a significant subsidiary to pay certain final judgments aggregating in excess of $25 million within 60 days; and
- any guarantee of the Notes by a guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

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. The recent improvement in the commodity price environment has increased development activities which has increased service costs. If the Williston Basin development activities remain at the current levels, we expect business costs will increase 5-10% in 2018 due to increased demand for materials, services and personnel.

Contractual Obligations and Commitments

Our material long-term debt obligations, capital lease obligations and operating lease obligations or purchase obligations as of December 31, 2017 are included in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

Significant Accounting Policies

Our critical accounting policies involving significant estimates include impairment testing of natural gas and crude oil production properties, asset retirement obligations, revenue recognition, derivative instruments and hedging activity, and income taxes. There were no material changes in our critical accounting policies involving significant estimates from those reported in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

A description of our critical accounting policies was provided in Note 2 to our financial statements provided in Part II, Item 8 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017 and, except as set forth below, have not materially changed since that report was filed.

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 our management believes 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 have been funded by cash from operations or borrowings under our term loan credit agreement. As of March 31, 2018, we have entered into derivative swap agreements covering 2.2 million barrels of oil for the remainder of 2018 at an average price of $53.33 per barrel, 2.2 million barrels of oil in 2019 at an average price of $52.64 per barrel, 1.4 million in 2020 at an average price of $50.77 and 0.3 million in 2021 at an average price of $52.72 per barrel.

The following table reflects open commodity swap contracts as of March 31, 2018, the associated volumes and the corresponding fixed price.

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Settlement Period	Oil (Barrels)	Fixed Price ($)
Swaps-Crude Oil		
04/01/18 – 08/31/18	100,000	49.99
04/01/18 – 08/31/18	100,000	50.04
04/01/18 – 08/31/18	100,000	49.99
04/01/18 – 08/31/18	100,000	50.17
04/01/18 – 09/30/18	180,000	53.99
04/01/18 – 09/30/18	180,000	53.99
04/01/18 – 09/30/18	183,000	55.19
04/01/18 – 12/31/18	135,000	53.30
04/01/18 – 12/31/18	275,000	54.80
04/01/18 – 12/31/18	275,000	54.09
04/01/18 – 12/31/18	275,000	54.42
10/01/18 – 12/31/18	92,000	52.50
10/01/18 – 12/31/18	92,000	52.55
10/01/18 – 12/31/18	46,000	54.50
10/01/18 – 12/31/18	92,000	52.50
01/01/19 – 03/31/19	45,000	54.22
01/01/19 – 03/31/19	63,000	53.65
01/01/19 – 12/31/19	365,000	51.05
01/01/19 – 12/31/19	365,000	51.05
01/01/19 – 12/31/19	182,500	52.70
01/01/19 – 12/31/19	365,000	51.05
01/01/19 – 12/31/19	182,500	52.15
01/01/19 – 12/31/19	182,500	52.75
01/01/19 – 12/31/19	219,000	57.30
01/01/19 – 06/30/19	108,600	57.90
04/01/19 – 06/30/19	45,500	53.59
04/01/19 – 06/30/19	36,400	53.10
07/01/19 – 09/30/19	46,000	53.07
07/01/19 – 09/30/19	9,200	52.65
01/01/20 – 03/31/20	27,300	51.81
01/01/20 – 03/31/20	45,500	54.05
01/01/20 – 03/31/20	45,500	54.25
01/01/20 – 03/31/20	27,300	54.65
01/01/20 – 12/31/20	366,000	49.77
01/01/20 – 12/31/20	183,000	51.30
01/01/20 – 12/31/20	109,800	51.70
01/01/20 – 12/31/20	366,000	49.75
01/01/20 – 12/31/20	183,000	51.10
04/01/20 – 06/30/20	9,100	51.50
04/01/20 – 06/30/20	9,100	54.70
01/01/21 – 03/31/21	90,000	52.50
01/01/21 – 03/31/21	90,000	53.00
01/01/21 – 03/31/21	90,000	52.55
01/01/21 – 03/31/21	18,000	53.20

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The following table reflects the weighted average price of open commodity swap derivative contracts as of March 31, 2018, by year with associated volumes.

Year	Volumes (Bbl)	Weighted Average Price ($)
2018	2,225,000	53.33
2019	2,215,200	52.64
2020	1,371,600	50.77
2021 and beyond	288,000	52.72

Interest Rate Risk

Our long-term debt is comprised of borrowings that contain fixed and floating interest rates. The Notes bear interest at an annual fixed rate of 8%, while our term loan credit agreement interest rate is floating based on an Adjusted LIBO Rate (subject to a 1% floor) plus 7.75% per annum margin. During the quarter ended March 31, 2018, we had $300.0 million in average outstanding borrowings under our term loan credit agreement at a weighted average rate of 9.5%. Interest payments are due under the term loan credit agreement in arrears on the last day of each March, June, September and December. All outstanding principal is due and payable upon termination of the term loan credit agreement.

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 March 31, 2018 would cost us approximately $3.0 million in additional annual interest expense.

Item 4. 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 March 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 March 31, 2018.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended March 31, 2018, that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PART II - OTHER INFORMATION

Item 1. 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 August 18, 2016, plaintiff 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, Michael Reger (our former chief executive officer), and Thomas Stoelk (our former chief financial officer and interim chief executive officer) as defendants. An amended complaint was filed by plaintiffs in July 2017. Defendants (including the Company) filed a motion to dismiss the amended complaint in August 2017. The court granted the Company's motion to dismiss 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 complaint purports 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 seeks 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. The Company intends to continue to vigorously defend itself in this matter.

Item 1A. Risk Factors.

There have been no material changes to the risk factors disclosed in the "Risk Factors" section of our Annual Report on Form 10-K filed with the SEC for the period ended December 31, 2017.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Recent Sales of Unregistered Securities

None.

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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 March 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 January 1, 2018 to January 31, 2018	—	$ —	—	$ 108.3 million
Month #2 February 1, 2018 to February 28, 2018	397	2.29	—	108.3 million
Month #3 March 1, 2018 to March 31, 2018	89,204	2.10	—	108.3 million
Total	89,601	$ 2.10	—	$ 108.3 million

(1) All shares purchased reflect shares surrendered in satisfaction of tax 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 shares of our outstanding common stock. In total, we have repurchased 3,190,268 shares under this program through March 31, 2018 at a weighted average price of $13.06 per share.

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Item 6. Exhibits.

Unless otherwise indicated, all documents incorporated by reference to a document filed with the SEC pursuant to the Exchange Act, are located under SEC file number 001-33999.

Exhibit No.	Description	Reference
3.1	Amended and Restated Articles of Incorporation of Northern Oil and Gas, Inc. dated June 1, 2016	Incorporated by reference to Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016
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 July 2, 2010
4.1	Specimen Stock Certificate of Northern Oil and Gas, Inc.	Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K filed with the SEC on February 29, 2012
4.2	Indenture, dated May 18, 2012, 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, 2012
4.3	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
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	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
12.1	Calculation of Ratio of Earnings to Fixed Charges	Filed herewith
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 and Principal Accounting 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
32.1	Certification of the Principal Executive Officer and Principal Financial Officer and Principal Accounting Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	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

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101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith

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SIGNATURES

In accordance with the requirements of the Exchange Act, the Registrant has caused this Quarterly Report to be signed on its behalf by the undersigned, thereunto duly authorized.

NORTHERN OIL AND GAS, INC.

Date:	May 7, 2018	By: /s/ Brandon Elliott
		Brandon Elliott, Interim President, Principal Executive Officer
Date:	May 7, 2018	By: /s/ Chad Allen
		Chad Allen, Interim Chief Financial Officer, Chief Accounting Officer, Principal Financial Officer, Principal Accounting Officer