**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**WASHINGTON, DC 20549**

# FORM 10-Q

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

**For the quarterly period ended September 30, 2019**

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

**For the transition period from ____________ to____________**

**Commission File No. 001-33999**

# NORTHERN OIL AND GAS, INC.

(Exact Name of Registrant as Specified in Its Charter)

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

**601 Carlson Pkwy – Suite 990**
**Minnetonka, Minnesota 55305**
(Address of Principal Executive Offices)

**(952) 476-9800**
(Registrant's Telephone Number)

**N/A**
(Former Name, Former Address and Former Fiscal Year, if Changed Since Last Report)

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

| Title of each class | Trading Symbol(s) | Name of each exchange on which registered |
|---|---|---|
| Common Stock, par value $0.001 | NOG | NYSE American |

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

Indicate by check mark whether the registrant has submitted electronically every interactive data file required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or 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 ☒ |
| Non-Accelerated Filer ☐ | Smaller Reporting Company ☐ |
| | Emerging Growth Company ☐ |

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes☐ No ☒

As of November 8, 2019, there were 405,787,759 shares of our common stock, par value $0.001, outstanding.

## 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.

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

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

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

"*Field.*" An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"*Proved developed non-producing reserves (PDNPs)*." Proved crude oil, NGLs, and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

"*Proved reserves*." The quantities of crude oil, NGLs and natural gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

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

"*Proved undeveloped reserves*" or "*PUDs*." Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir or an analogous reservoir.

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

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

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

**NORTHERN OIL AND GAS, INC.**
**FORM 10-Q**

**September 30, 2019**

**C O N T E N T S**

## PART I - FINANCIAL INFORMATION

### Item 1. *Condensed Financial Statements.*

### NORTHERN OIL AND GAS, INC.
### CONDENSED BALANCE SHEETS

| *(In thousands, except par value and share data)* | September 30, 2019 | December 31, 2018 |
|---|---|---|
| **ASSETS** | (Unaudited) | |
| Current Assets: | | |
| Cash and Cash Equivalents | $ 1,901 | $ 2,358 |
| Accounts Receivable, Net | 103,226 | 96,353 |
| Advances to Operators | 1,314 | 268 |
| Prepaid Expenses and Other | 2,717 | 12,360 |
| Derivative Instruments | 62,531 | 115,870 |
| Income Tax Receivable | 420 | 1,205 |
| Total Current Assets | 172,110 | 228,415 |
| | | |
| Property and Equipment: | | |
| Oil and Natural Gas Properties, Full Cost Method of Accounting | | |
| Proved | 4,043,897 | 3,431,428 |
| Unproved | 11,145 | 4,307 |
| Other Property and Equipment | 1,999 | 998 |
| Total Property and Equipment | 4,057,041 | 3,436,732 |
| Less – Accumulated Depreciation, Depletion and Impairment | (2,380,086) | (2,233,987) |
| Total Property and Equipment, Net | 1,676,955 | 1,202,745 |
| | | |
| Derivative Instruments | 42,682 | 61,843 |
| Deferred Income Taxes | 420 | 420 |
| Other Noncurrent Assets, Net | 9,842 | 10,223 |
| | | |
| Total Assets | $ 1,902,009 | $ 1,503,645 |
| | | |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current Liabilities: | | |
| Accounts Payable | $ 112,698 | $ 55,015 |
| Accrued Liabilities | 90,114 | 83,237 |
| Accrued Interest | 17,567 | 16,468 |
| Debt Exchange Derivative | — | 18,183 |
| Contingent Consideration | 10,058 | 58,069 |
| Other Current Liabilities | 387 | 555 |
| Total Current Liabilities | 230,824 | 231,526 |
| | | |
| Long-term Debt, Net | 1,140,072 | 830,203 |
| Asset Retirement Obligations | 16,582 | 11,946 |
| Other Noncurrent Liabilities | 417 | 105 |
| | | |
| **TOTAL LIABILITIES** | $ 1,387,894 | $ 1,073,780 |
| | | |
| **COMMITMENTS AND CONTINGENCIES (NOTE 8)** | | |
| | | |
| **STOCKHOLDERS' EQUITY** | | |
| Preferred Stock, Par Value $.001; 5,000,000 Authorized, No Shares Outstanding | — | — |

| | | |
|---|---|---|
| Common Stock, Par Value $.001; 675,000,000 Shares Authorized;<br>404,346,470 Shares Outstanding at 9/30/2019<br>378,333,070 Shares Outstanding at 12/31/2018 | 404 | 378 |
| Additional Paid-In Capital | 1,278,976 | 1,226,371 |
| Retained Deficit | (765,266) | (796,884) |
| Total Stockholders' Equity | 514,114 | 429,865 |
| **TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY** | $ 1,902,009 | $ 1,503,645 |

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

**NORTHERN OIL AND GAS, INC.**
**CONDENSED STATEMENTS OF OPERATIONS**
**(UNAUDITED)**

| *(In thousands, except share and per share data)* | Three Months Ended September 30, 2019 | Three Months Ended September 30, 2018 | Nine Months Ended September 30, 2019 | Nine Months Ended September 30, 2018 |
|---|---|---|---|---|
| **REVENUES** | | | | |
| Oil and Gas Sales | $ 157,989 | $ 145,416 | $ 440,519 | $ 341,343 |
| Gain (Loss) on Derivative Instruments, Net | 75,892 | (43,148) | (27,139) | (105,622) |
| Other Revenue | 3 | 2 | 10 | 5 |
| Total Revenues | 233,883 | 102,269 | 413,389 | 235,729 |
| **OPERATING EXPENSES** | | | | |
| Production Expenses | 32,347 | 18,161 | 83,146 | 45,198 |
| Production Taxes | 15,391 | 13,579 | 41,944 | 31,633 |
| General and Administrative Expense | 4,206 | 4,674 | 15,506 | 9,593 |
| Depletion, Depreciation, Amortization and Accretion | 55,566 | 30,258 | 146,791 | 71,485 |
| Impairment of Other Current Assets | 5,275 | — | 7,969 | — |
| Total Operating Expenses | 112,784 | 66,673 | 295,355 | 157,909 |
| **INCOME FROM OPERATIONS** | 121,100 | 35,597 | 118,034 | 77,820 |
| **OTHER INCOME (EXPENSE)** | | | | |
| Interest Expense, Net of Capitalization | (21,510) | (20,438) | (58,836) | (65,948) |
| Loss on the Extinguishment of Debt | — | (9,542) | (425) | (100,375) |
| Debt Exchange Derivative Gain/(Loss) | (23) | 13,063 | 1,390 | 13,063 |
| Contingent Consideration Loss | (5,262) | — | (28,633) | — |
| Other Income (Expense) | 75 | 299 | 88 | 838 |
| Total Other Income (Expense) | (26,719) | (16,618) | (86,416) | (152,423) |
| **INCOME (LOSS) BEFORE INCOME TAXES** | 94,381 | 18,979 | 31,619 | (74,603) |
| **INCOME TAX PROVISION (BENEFIT)** | — | — | — | — |
| **NET INCOME (LOSS)** | $ 94,381 | $ 18,979 | $ 31,619 | $ (74,603) |
| Net Income (Loss) Per Common Share – Basic | $ 0.24 | $ 0.06 | $ 0.08 | $ (0.40) |
| Net Income (Loss) Per Common Share – Diluted | $ 0.24 | $ 0.06 | $ 0.08 | $ (0.40) |
| Weighted Average Shares Outstanding – Basic | 396,044,887 | 300,517,497 | 382,044,068 | 188,152,998 |
| Weighted Average Shares Outstanding – Diluted | 396,530,767 | 301,755,419 | 382,744,304 | 188,152,998 |

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

**NORTHERN OIL AND GAS, INC.**
**CONDENSED STATEMENTS OF CASH FLOWS**
**(UNAUDITED)**

| *(In thousands)* | Nine Months Ended September 30, 2019 | Nine Months Ended September 30, 2018 |
|---|---|---|
| **CASH FLOWS FROM OPERATING ACTIVITIES** | | |
| Net Income (Loss) | $ 31,619 | $ (74,603) |
| Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities: | | |
| Depletion, Depreciation, Amortization and Accretion | 146,791 | 71,485 |
| Amortization of Debt Issuance Costs | 3,948 | 3,772 |
| Loss on Extinguishment of Debt | 425 | 100,375 |
| Amortization of Bond (Premium) Discount on Long-term Debt | (2,165) | 198 |
| Unrealized Loss of Derivative Instruments | 62,806 | 72,303 |
| Gain on Debt Exchange Derivative | (1,390) | (13,063) |
| Loss on Contingent Consideration | 28,633 | — |
| PIK Interest on Second Lien Notes | 1,742 | — |
| Stock-Based Compensation Expense | 4,280 | 2,092 |
| Impairment of Other Current Assets | 7,969 | — |
| Other | (41) | (112) |
| Changes in Working Capital and Other Items: | | |
| Accounts Receivable, Net | (6,589) | (43,341) |
| Prepaid and Other Expenses | 1,674 | (3,216) |
| Accounts Payable | 1,058 | 4,349 |
| Accrued Interest | 2,813 | 6,128 |
| Accrued Liabilities | 6,916 | 48 |
| Payment of Contingent Consideration | (21,164) | — |
| Net Cash Provided by Operating Activities | 269,323 | 126,416 |
| **CASH FLOWS FROM INVESTING ACTIVITIES** | | |
| Drilling and Development Capital Expenditures | (206,306) | (164,584) |
| Acquisition of Oil and Natural Gas Properties | (210,642) | (125,487) |
| Acquisition Deposit | — | (20,000) |
| Proceeds from Sale of Oil and Natural Gas Properties | — | 22 |
| Proceeds from Sale of Other Property and Equipment | — | 46 |
| Purchases of Other Property and Equipment | (1,001) | (87) |
| Net Cash Used for Investing Activities | (417,948) | (310,090) |
| **CASH FLOWS FROM FINANCING ACTIVITIES** | | |
| Advances on Revolving Credit Facility | 313,000 | — |
| Repayments on Revolving Credit Facility | (126,000) | — |
| Borrowings on Term Loan Credit Agreement | — | 60,000 |
| Repurchases of Second Lien Notes | (10,488) | — |
| Debt Issuance Costs Paid | (328) | (6,838) |
| Debt Exchange Derivative Settlements | (1,044) | — |
| Contingent Consideration Settlements | (11,278) | — |
| Issuance of Common Stock | — | 141,710 |
| Repurchases of Common Stock | (15,108) | — |
| Restricted Stock Surrenders - Tax Obligations | (584) | (415) |
| Net Cash Provided by Financing Activities | 148,169 | 194,457 |

| | | |
|---|---|---|
| **NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS** | (456) | 10,783 |
| **CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD** | 2,358 | 102,183 |
| **CASH AND CASH EQUIVALENTS – END OF PERIOD** | 1,901 | 112,966 |

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

**NORTHERN OIL AND GAS, INC.**
**CONDENSED STATEMENTS OF STOCKHOLDERS' EQUITY**
**(UNAUDITED)**

| | Common Stock | | Additional Paid-In | Retained | Total Stockholders' |
|---|---|---|---|---|---|
| *(In thousands, except share data)* | Shares | Amount | Capital | Deficit | Equity |
| **December 31, 2018** | 378,333,070 | $ 378 | $ 1,226,371 | $ (796,884) | $ 429,865 |
| Issuance of Common Stock | 3,160,200 | 3 | — | — | 3 |
| Restricted Stock Forfeitures | (4,802) | — | — | — | — |
| Stock-Based Compensation | — | — | 2,832 | — | 2,832 |
| Restricted Stock Surrenders - Tax Obligations | (220,531) | — | (558) | — | (558) |
| Repurchases of Common Stock | (5,635,003) | (6) | (15,102) | — | (15,108) |
| Contingent Consideration Settlements | 1,167,544 | 1 | 2,886 | — | 2,887 |
| Net Loss | — | — | — | (107,162) | (107,162) |
| **March 31, 2019** | 376,800,478 | $ 377 | $ 1,216,429 | $ (904,046) | $ 312,760 |
| Issuance of Common Stock | 9,000 | — | — | — | — |
| Restricted Stock Forfeitures | (402,033) | — | — | — | — |
| Stock-Based Compensation | — | — | 1,750 | — | 1,750 |
| Restricted Stock Surrenders - Tax Obligations | (9,440) | — | (26) | — | (26) |
| Debt Exchange Agreements | 5,249,879 | 5 | 12,186 | — | 12,192 |
| Contingent Consideration Settlements | 7,788,107 | 8 | 18,567 | — | 18,575 |
| Net Income | — | — | — | 44,399 | 44,399 |
| **June 30, 2019** | 389,435,991 | $ 389 | $ 1,248,906 | $ (859,647) | $ 389,649 |
| Restricted Stock Forfeitures | (45,600) | — | — | — | — |
| Stock-Based Compensation | — | — | (8) | — | (8) |
| Debt Exchange Agreements | 1,985,530 | 2 | 3,541 | — | 3,543 |
| Acquisition of Oil and Natural Gas Properties | 5,602,147 | 6 | 11,703 | — | 11,708 |
| Contingent Consideration Settlements | 7,368,402 | 7 | 14,833 | — | 14,841 |
| Net Income | — | — | — | 94,381 | 94,381 |
| **September 30, 2019** | 404,346,470 | 404 | 1,278,976 | (765,266) | 514,114 |

| (In thousands, except share data) | Common Stock Shares | Common Stock Amount | Additional Paid-In Capital | Retained Deficit | Total Stockholders' Equity (Deficit) |
|---|---|---|---|---|---|
| **December 31, 2017** | 66,791,633 | $ 67 | $ 449,666 | $ (940,574) | $ (490,841) |
| Issuance of Common Stock | 127,999 | — | — | — | — |
| Restricted Stock Forfeitures | (892,086) | (1) | — | — | (1) |
| Stock-Based Compensation | — | — | (712) | — | (712) |
| Restricted Stock Surrenders - Tax Obligations | (89,601) | — | (188) | — | (188) |
| Net Income | — | — | — | 2,965 | 2,965 |
| **March 31, 2018** | 65,937,945 | $ 66 | $ 448,766 | $ (937,609) | $ (488,776) |
| Issuance of Common Stock | 3,025,303 | 3 | — | — | 3 |
| Stock-Based Compensation | — | — | 1,397 | — | 1,397 |
| Restricted Stock Surrenders - Tax Obligations | (63,820) | — | (161) | — | (161) |
| Equity Offerings | 96,926,019 | 97 | 141,613 | — | 141,710 |
| Debt Exchange Agreements | 121,774,822 | 122 | 279,192 | — | 279,314 |
| Acquisition of Oil and Natural Gas Properties | 6,000,000 | 6 | 15,234 | — | 15,240 |
| Net Loss | — | — | — | (96,547) | (96,547) |
| **June 30, 2018** | 293,600,269 | $ 294 | $ 886,041 | $ (1,034,155) | $ (147,820) |
| Issuance of Common Stock | 42,000 | — | — | — | — |
| Restricted Stock Forfeitures | (18,000) | — | — | — | — |
| Stock-Based Compensation | — | — | 1,655 | — | 1,655 |
| Restricted Stock Surrenders - Tax Obligations | (19,338) | — | (66) | — | (66) |
| Equity Offerings | — | — | — | — | — |
| Debt Exchange Agreements | 14,288,977 | 14 | 48,171 | — | 48,185 |
| Acquisition of Oil and Natural Gas Properties | 26,253,578 | 26 | 90,251 | — | 90,277 |
| Net Exercise of Stock Options | 62,500 | — | — | — | — |
| Net Income | — | — | — | 18,979 | 18,979 |
| **September 30, 2018** | 334,209,986 | 334 | 1,026,053 | (1,015,177) | 11,210 |

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

## NOTES TO CONDENSED FINANCIAL STATEMENTS
## SEPTEMBER 30, 2019
## (UNAUDITED)

### NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

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

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

For the nine months ended September 30, 2019, crude oil accounted for81% of the Company's total production and 94% of its oil and gas sales.

### NOTE 2 BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The financial information included herein is unaudited. The balance sheet as of December 31, 2018 has been derived from the Company's audited financial statements for the year ended December 31, 2018. 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, 2018, which were included in the Company's 2018 Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

The preparation of financial statements under GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to proved crude oil and natural gas reserves, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of derivative instruments, fair value of contingent consideration, acquisition date fair values of assets acquired and liabilities assumed, impairment of oil and natural gas properties, asset retirement obligations and deferred income taxes. Actual results may differ from those estimates.

Reclassifications

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

Correction of Presentation

Subsequent to the issuance of the Company's condensed financial statements as of and for the period ended September 30, 2018, the Company identified an immaterial error in the supplemental footnote disclosure of non-cash investing activities in which a "Change in Prepaid Expenses and Other" was improperly included in the amount of $12.4 million. Accordingly, within the "Supplemental Cash Flow Information" section included in this Note 2 below, the Company has removed the line item previously reported as the amount of "Change in Prepaid Expenses and Other." The error did not impact the Statement of Cash Flows.

Adopted and Recently Issued Accounting Pronouncements

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2016-02, Leases ("ASU 2016-02"). The objective of this ASU is to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. FASB subsequently issued various ASUs which provided additional implementation guidance, and these ASUs collectively make up FASB ASC Topic 842 – Leases ("ASC 842"). ASC 842 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. The standard permits retrospective application through recognition of a cumulative-effect adjustment at the beginning of either the earliest reporting period presented or the period of adoption. ASC 842 does not apply to leases used in the exploration or use of minerals, oil, natural gas, or other similar non-regenerative resources. The Company adopted ASC 842 effective January 1, 2019 using the modified retrospective method as of the adoption date. The Company has completed the assessment of its existing accounting policies and enhancement of its internal controls. The standard did not have a material impact on the Company's condensed balance sheets, statement of operations or cash flows.

In June 2016 FASB issued ASU 2016-13, Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. This standard changes how entities will measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The standard will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost. The standard is effective for interim and annual periods beginning after December 15, 2019 and shall be applied using a modified retrospective approach resulting in a cumulative effect adjustment to retained earnings upon adoption. The Company continues to evaluate the new standard and is unable to estimate its financial statement impact at this time; however, the impact is not expected to be material.

Revenue Recognition

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

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

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

A wellhead imbalance liability equal to the Company's share is recorded to the extent that the Company's well operators have sold volumes in excess of its share of remaining reserves in an underlying property. However, for the three and nine months ended September 30, 2019 and 2018, 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 the Company only operates inone geographic area, the Williston Basin in the United States, primarily in North Dakota and Montana. Oil sales for the three months ended September 30, 2019 and 2018 were $152.8 million and $135.0 million, respectively. Natural gas and NGL sales for the three months ended September 30, 2019 and 2018 were $5.2 million and $10.4 million, respectively. Oil sales for the nine months ended September 30, 2019 and 2018 were $416.3 million and $315.2 million, respectively. Natural gas and NGL sales for the nine months ended September 30, 2019 and 2018 were $24.3 million and $26.2 million, respectively.

Net Income (Loss) Per Common Share

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

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three and nine months ended September 30, 2019 and 2018 are as follows:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| ***(In thousands, except share and per share data)*** | **2019** | **2018** | **2019** | **2018** |
| Net Income (Loss) | $ 94,381 | $ 18,979 | $ 31,619 | $ (74,603) |
| Weighted Average Common Shares Outstanding: | | | | |
| Weighted Average Common Shares Outstanding – Basic | 396,044,887 | 300,517,497 | 382,044,068 | 188,152,998 |
| Plus: Potentially Dilutive Common Shares Including Stock Options and Restricted Stock | 485,880 | 1,237,922 | 700,236 | — |
| Weighted Average Common Shares Outstanding – Diluted | 396,530,767 | 301,755,419 | 382,744,304 | 188,152,998 |
| | | | | |
| Net Income (Loss) per Common Share: | | | | |
| Basic | $ 0.24 | $ 0.06 | $ 0.08 | $ (0.40) |
| Diluted | $ 0.24 | $ 0.06 | $ 0.08 | $ (0.40) |
| | | | | |
| Shares underlying Restricted Stock Awards and Stock Options Excluded from EPS Due to Anti-Dilutive Effect | 88,209 | — | 40,330 | 617,429 |

Supplemental Cash Flow Information

The following reflects the Company's supplemental cash flow information:

| | Nine Months Ended September 30, | |
|---|---|---|
| *(In thousands)* | **2019** | **2018** |
| **Supplemental Cash Items:** | | |
| Cash Paid During the Period for Interest | $ 52,916 | $ 55,849 |
| | | |
| **Non-cash Operating Activities:** | | |
| Contingent Consideration Settlements in excess of acquisition-date liabilities | 18,480 | — |
| | | |
| **Non-cash Investing Activities:** | | |
| Oil and Natural Gas Properties Included in Accounts Payable and Accrued Liabilities | 178,772 | 108,216 |
| Capitalized Asset Retirement Obligations | 3,703 | 1,644 |
| Compensation Capitalized on Oil and Gas Properties | 296 | 250 |
| Issuance of Common Stock - Acquisitions of Oil and Natural Gas Properties | 11,708 | 105,517 |
| Issuance of VEN Bakken Note | 128,660 | — |
| | | |
| **Non-cash Financing Activities:** | | |
| Exchange transactions - non-cash securities issued: | | |
| Issuance of 8.50% Second Lien Notes due 2023 | — | 344,279 |
| Issuance of Common Stock - fair value at issuance date | — | 326,783 |
| Debt Exchange Derivative Liability - fair value at issuance date | — | 19,354 |
| Issuance of 8.50% Second Lien Notes due 2023 - PIK Interest | 3,480 | — |
| Debt Exchange Derivative Liability Settlements | 15,735 | — |
| Contingent Consideration Settlements | 17,822 | — |
| Exchange Transactions - non-cash securities exchanged: | | |
| 8.00% Unsecured Senior Notes due 2020 - carrying value | — | (590,041) |

**NOTE 3 CRUDE OIL AND NATURAL GAS PROPERTIES**

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

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 Company did not have any ceiling test impairment for the three and nine months ended September 30, 2019 and 2018, respectively.

The book 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. Acquired assets and liabilities assumed are recorded based on their estimated fair value at the time of the acquisition. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities.

2019 Acquisitions

Not including the VEN Bakken Acquisition described below, the Company acquired oil and natural gas properties, through a number of independent transactions, for a total of $19.1 million and $36.3 million during the three and nine months ended September 30, 2019, respectively. These amounts include $9.2 million and $11.3 million, respectively, of development costs that occurred prior to the closings of the acquisitions.

*VEN Bakken Acquisition*

On July 1, 2019, the Company completed its acquisition (the "VEN Bakken Acquisition") of certain oil and gas properties and interests from VEN Bakken, LLC ("VEN Bakken"), effective as of July 1, 2019. VEN Bakken is a wholly-owned subsidiary of Flywheel Bakken, LLC. At closing the acquired assets consisted of approximately 90.1 net producing wells and 3.3 net wells in process, as well as approximately 18,000 net acres substantially all in North Dakota. The Company also assumed certain crude oil derivative contracts from VEN Bakken as part of the acquisition. The VEN Bakken Acquisition was completed pursuant to the purchase and sale agreement between the Company and VEN Bakken, dated as of April 18, 2019.

The total estimated consideration paid by the Company was $312.4 million, consisting of (i) $172.1 million in cash, (ii) 5,602,147 shares of Company common stock valued at $11.7 million, based on the $2.09 per share closing price of Company common stock on the closing date of the acquisition and (iii) $128.7 million of value attributable to a 6.0% unsecured promissory note due July 1, 2022 issued by the Company to VEN Bakken in the aggregate principal amount of $130.0 million (the "Unsecured VEN Bakken Note"). The results of operations from the July 1, 2019 closing date through September 30, 2019, represented approximately $26.1 million of revenue and $10.0 million of income from operations. The Company incurred $1.8 million of transactions costs in connection with the acquisition, which are included in general and administrative expense in the condensed statement of operations. The following table reflects the preliminary fair values of the net assets and liabilities as of the date of acquisition:

| | ***(In thousands)*** |
|---|---|
| **Fair value of net assets:** | |
| Proved oil and natural gas properties | $ 322,128 |
| Asset retirement cost | 2,680 |
| Total assets acquired | 324,808 |
| Asset retirement obligations | (2,680) |
| Derivative instruments | (9,694) |
| Net assets acquired | $ 312,434 |
| | |
| **Fair value of consideration paid for net assets:** | |
| Cash consideration | $ 172,066 |
| Issuance of common stock (5.6 million shares at $2.09 per share) | 11,708 |
| Unsecured VEN Bakken Note | 128,660 |
| Total fair value of consideration transferred | $ 312,434 |

2018 Acquisitions

*W Energy Acquisition*

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

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

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

*Pivotal Acquisition*

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

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

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

*Salt Creek Acquisition*

On April 25, 2018, the Company entered into a purchase and sale agreement with Salt Creek Oil and Gas, LLC, to acquire 64 gross, 5.5 net producing (PDP) wells, 31 gross, 1.5 net drilling and completing (PDNP) wells and 1,319 net acres located in McKenzie and Mountrail counties of North Dakota. On June 4, 2018, the Company closed the transaction for consideration of $60.0 million which is comprised of $44.7 million of cash consideration and $15.2 million of common stock consideration. No material transaction costs were incurred in connection with this acquisition. The following table reflects the fair values of the net assets and liabilities as of the date of acquisition:

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

Pro Forma Information

The following summarized unaudited pro forma condensed statement of operations information for the three and nine months ended September 30, 2018, and for the nine months ended September 30, 2019, assumes that the VEN Bakken Acquisition, the W Energy Acquisition and the Pivotal Acquisition each occurred as of January 1, 2018. There is no pro forma information included for the three months ended September 30, 2019, because the Company's actual financial results for such period fully reflect these acquisitions. The Company prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma information may not be indicative of the results that would have occurred had the Company completed all of these acquisitions as of January 1, 2018, or that would be attained in the future.

| *(In thousands)* | Nine Months Ended September 30, 2019 | Three Months Ended September 30, 2018 | Nine Months Ended September 30, 2018 |
|---|---|---|---|
| Revenues | $ 441,716 | $ 176,312 | $ 436,727 |
| Net Income (Loss) | 11,564 | 34,725 | (41,221) |

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

The Company 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.

Capitalized costs associated with impaired unproved properties and capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs, are depleted and amortized on the unit-of-production method. Under this method, depletion is calculated at the end of each period by multiplying total production for the period by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the period. The costs of unproved properties are withheld from the depletion base until such time as they are either developed or abandoned. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion and full cost ceiling calculations. For the three months ended September 30, 2019 and 2018, the Company expired leases of $0.8 million and $3.1 million, respectively. For the nine months ended September 30, 2019 and 2018, the Company expired leases of $2.5 million and $8.1 million, respectively.

## NOTE 4 LONG-TERM DEBT

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

| *(In thousands)* | September 30, 2019 | | | |
|---|---|---|---|---|
| | Principal Balance | Unamortized Premium/(Discount) | Debt Issuance Costs, Net | Long-term Debt, Net |
| Second Lien Notes due 2023 | $ 688,491 | $ 10,814 | $ (14,817) | $ 684,488 |
| Revolving Credit Facility[1] | 327,000 | — | — | 327,000 |
| Unsecured VEN Bakken Note | 130,000 | (1,256) | (160) | 128,584 |
| Total | $ 1,145,491 | $ 9,558 | $ (14,977) | $ 1,140,072 |

| | December 31, 2018 | | | |
|---|---|---|---|---|
| | Principal Balance | Unamortized Premium | Debt Issuance Costs, Net | Long-term Debt, Net |
| Second Lien Notes due 2023 | $ 695,140 | $ 13,237 | $ (18,173) | $ 690,203 |
| Revolving Credit Facility[1] | 140,000 | — | — | 140,000 |
| Total | $ 835,140 | $ 13,237 | $ (18,173) | $ 830,203 |

(1) Debt issuance costs related to the Company's revolving credit facility of $4.4 million and $5.1 million as of September 30, 2019 and December 31, 2018, respectively, are recorded in "Other Noncurrent Assets, Net" on the balance sheets.

Revolving Credit Facility

On October 5, 2018, the Company entered into a $750.0 million revolving credit facility (the "Revolving Credit Facility") with Royal Bank of Canada, as administrative agent, and the lenders from time to time party thereto. The revolving credit agreement is scheduled to mature 5 years from the closing date, provided that the maturity date shall be91 days prior to the scheduled maturity date of the earlier of (i) the Second Lien Notes (defined below) if any Second Lien Notes remain outstanding on such date or (ii) the Purchaser Note (as defined in Note 12 below) if any principal amount of the Purchaser Note remains outstanding on such date.

The revolving credit agreement is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to the Company and its subsidiaries' (if any) oil and gas properties. The borrowing base as of September 30, 2019 was $425.0 million, which is the maximum amount of borrowings that the indenture for the Second Lien Notes permits the Company to have outstanding under the Revolving Credit Facility. The borrowing base will be redetermined semiannually on or around April 1st and October 1st, with one interim "wildcard" redetermination available between scheduled redeterminations. The April 1st scheduled redetermination shall be based on a January 1st engineering report audited by a 3rd party (reasonably acceptable by the Agent).

At the Company's option, borrowings under the revolving credit agreement shall bear interest at the base rate or LIBOR plus an applicable margin. Base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from75 to 175 basis points, and the applicable margin for LIBOR loans ranges from 175 to 275 basis points, in each case depending on the percentage of the borrowing base utilized.

The revolving credit agreement contains negative covenants that limit the Company's ability, among other things, to pay dividends, incur additional indebtedness, sell assets, enter into certain derivatives contracts, change the nature of its business or operations, merge, consolidate, or make certain types of investments. In addition, the revolving credit agreement requires that the Company comply with the following financial covenants: (i) as of the date of determination, the ratio of total net debt to EBITDAX (as defined in the revolving credit agreement) shall be no more than 4.00 to 1.00, measured on a pro forma rolling four quarter basis, and (ii) the current ratio (defined as consolidated current assets including unused amounts of the total commitments, but excluding non-cash assets under ASC 815, divided by consolidated current liabilities excluding current non-cash obligations under ASC 815 and current maturities under the Revolving Credit Facility, the Second Lien Notes and the Unsecured VEN Bakken Note) is not permitted to be less than 1.00. See Note 12 below regarding recent amendments to the foregoing covenants.

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

The Company's obligations under the Revolving Credit Facility are secured by mortgages on not less than 85% of the value of proven reserves associated with the oil and gas properties included in the determination of the borrowing base. Additionally, the Company entered into a Guaranty and Collateral Agreement in favor of the Agent for the secured parties, pursuant to which the Company's obligations under the revolving credit agreement are secured by a first priority security interest in substantially all of the Company's assets.

Second Lien Notes due 2023

On May 15, 2018, the Company issued 8.500% senior secured second lien notes due 2023 (the "Second Lien Notes") with an aggregate principal amount of $344.3 million (the "Original 2L Notes") in exchange for certain previously outstanding 8.000% senior unsecured notes due June 1, 2020 (the "Unsecured Notes"). On October 5, 2018, the Company issued an additional $350.0 million aggregate principal amount of Second Lien Notes (the "Additional 2L Notes"), the proceeds of which were used in connection with the retirement of the Company's prior term loan credit agreement. In addition, as of and through September 30, 2019, the Company had issued another $4.3 million of additional aggregate principal amount of Second Lien Notes pursuant to the interest payment-in-kind provisions thereof.

During the nine months ended September 30, 2019, the Company repurchased and retired $10.1 million in aggregate principal amount of Second Lien Notes.

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

The Second Lien Notes are the senior secured obligations of the Company and rank equal in right of payment to all existing and future senior indebtedness of the Company and its subsidiaries. The Second Lien Notes are secured by second priority security interests in substantially all assets of the Company, subject to certain exceptions. The Second Lien Notes will be guaranteed by all of the Company's direct and indirect subsidiaries that guarantee indebtedness under any other indebtedness for borrowed money of the Company or any of the Company's subsidiary guarantors. As of September 30, 2019, the Company did not have any subsidiaries. The Second Lien Notes will mature on May 15, 2023.

Interest on the Second Lien Notes accrues at a rate of 8.500% per annum payable in cash quarterly in arrears on the first day of each calendar quarter. Beginning on July 1, 2018, the interest rate was increased by 1.000% per annum, which increase shall be payable in kind (the "PIK Component"). Commencing June 30, 2018, and as of each December 31st and June 30th thereafter, if the Company's total debt to EBITDAX ratio is (i) less than 3.00 to 1.00 as of such date, the PIK Component shall cease accruing effective as of the next interest payment date, or (ii) greater than or equal to 3.00 to 1.00 as of such date or if the Company fails to deliver financial statements, the PIK Component shall continue to accrue (or, if then not accruing, automatically commence accruing as of the next interest payment date) and be payable quarterly. The PIK Component began accruing on June 30, 2018 and ceased accruing on March 31, 2019. Additionally, if the Company incurs junior lien or unsecured debt with a cash interest rate in excess of 9.500%, the cash rate on the Second Lien Notes will be increased by such excess. Default interest will be payable in cash on demand at the then applicable interest rate plus 3.000% per annum.

The Company may redeem all or a portion of any of the Second Lien Notes at the following redemption prices during the following time periods (plus accrued and unpaid interest on the Second Lien Notes redeemed): (i) from and after May 15, 2018 until May 15, 2021, 104%, (ii) on and after May 15, 2021 until May 15, 2022, 102%, and (iii) on and after May 15, 2022, 100%; provided that any redemption of Second Lien Notes (or the acceleration of Second Lien Notes) prior to May 15, 2020 shall also be accompanied by a make whole premium. Subject to the terms of an intercreditor agreement, the Company is also required to offer to prepay the Second Lien Notes with 100% of the net cash proceeds of asset sales, casualty events and condemnations in excess of $20.0 million not required to be used to pay down the loans under the Revolving Credit Facility, subject to customary exclusions and reinvestment provisions. Mandatory prepayment offers will be subject to payment of the make whole premium and redemption price set forth above, as applicable.

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

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

Unsecured VEN Bakken Note

On July 1, 2019, in connection with the completion of the VEN Bakken Acquisition, the Company issued the Unsecured VEN Bakken Note in the original principal amount of $130.0 million. Fifty percent (50%) of the original principal amount of the Unsecured VEN Bakken Note is required to be repaid by the Company on or before January 1, 2021, and the remaining unpaid principal amount is required to be repaid by the Company on or before July 1, 2022, in each case together with all accrued but unpaid interest thereon. Interest, at a rate of 6.0% per annum, is due quarterly in arrears on the first day of each calendar quarter, commencing on October 1, 2019. The Unsecured VEN Bakken Note does not include any financial maintenance covenants and is unsecured.

The obligations of the Company under the Unsecured VEN Bakken Note may be accelerated, subject to certain grace and cure periods, upon the occurrence of an event of default. Events of default include customary events, including, without limitation, payment defaults, the inaccuracy of representations and warranties, defaults in the performance of certain affirmative or negative covenants, defaults on other indebtedness of the Company, and bankruptcy or insolvency related defaults. The Unsecured VEN Bakken Note contains negative covenants that limit the Company's ability, among other things, to pay dividends, repurchase equity, incur additional indebtedness, sell assets, terminate or unwind certain derivatives contracts, change the nature of its business or operations and merge or consolidate. In addition, the Unsecured VEN Bakken Note is subject to a mandatory prepayment offer in connection with a change of control.

## NOTE 5 COMMON AND PREFERRED STOCK

The Company's Restated Certificate of Incorporation authorizes the issuance of up to 680,000,000 shares. The shares are classified in two classes, consisting of 675,000,000 shares of common stock, par value $0.001 per share, and 5,000,000 shares of preferred stock, par value $0.001 per share. The board of directors is authorized to establish one or more series of preferred stock, setting forth the designation of each such series, and fixing the relative rights and preferences of each such series. The Company has neither designated nor issued any shares of preferred stock.

Common Stock

The following is a schedule of changes in the number of shares of common stock outstanding during the nine months ended September 30, 2019 and the year ended December 31, 2018:

| *(In thousands)* | Nine Months Ended September 30, 2019 | Year Ended December 31, 2018 |
|---|---|---|
| Beginning Balance | 378,333 | 66,792 |
| Repurchases of Common Stock | (5,635) | (7,360) |
| Stock Options Exercised - Net | — | 63 |
| Restricted Stock Grants | 3,169 | 3,295 |
| Debt Exchanges | 7,235 | 136,064 |
| Equity Offerings | — | 96,926 |
| Stock Consideration for Acquisitions of Oil and Natural Gas Properties | 5,602 | 83,731 |
| Contingent Consideration Settlements | 16,324 | — |
| Other Surrenders - Tax Obligations | (230) | (267) |
| Other Forfeitures | (452) | (911) |
| Ending Balance | 404,346 | 378,333 |

2019 Activity

During the nine months ended September 30, 2019,0.2 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 $0.6 million, which is based on the market prices on the dates the shares were surrendered.

During the nine months ended September 30, 2019, the Company issued5.6 million shares of common stock as consideration for the VEN Bakken Acquisition (see Note 3).

During the nine months ended September 30, 2019, the Company elected to issue8.8 million shares of common stock to satisfy contingent consideration owed in connection with the Pivotal Acquisition (see Note 3).

During the nine months ended September 30, 2019, the Company elected to issue7.6 million shares of common stock to satisfy contingent consideration owed in connection with the W Energy Acquisition (see Note 3).

During the nine months ended September 30, 2019, the Company elected to issue7.2 million shares of common stock to satisfy obligations owed in connection with the debt exchange derivative liabilities (see Note 10).

Stock Repurchase Program

In May 2011, the Company's board of directors approved a stock repurchase program to acquire up to $150.0 million of the Company's outstanding common stock. The stock repurchase program allows the Company to repurchase its shares from time to time in the open market, block transactions and in negotiated transactions.

During the nine months ended September 30, 2019, the Company repurchased5.6 million shares of its common stock under the stock repurchase program at a total cost of $16.3 million, of which $1.2 million was recorded as a settlement of contingent consideration liabilities. During the three months ended September 30, 2019 and the three and nine months ended September 30, 2018, 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-BASED COMPENSATION**

The Company's 2018 Equity Incentive Plan (the "2018 Plan"), which replaced the Company's prior 2013 Incentive Plan (the "2013 Plan"), authorized15,000,000 shares for grant under the 2018 Plan, plus the 769,775 shares remaining available for future grants under the 2013 Plan on the date the stockholders approved the 2018 Plan. No future awards will be made under the 2013 Plan. The 2013 Plan continues to govern awards that were made thereunder, which remain in effect pursuant to their terms. As of September 30, 2019, there were 12,953,010 shares available for future awards under the 2018 Plan.

The Company recognizes the fair value of stock-based compensation awards expected to vest over the requisite service period as a charge against earnings, net of amounts capitalized. The Company's stock-based compensation awards are accounted for as equity instruments and are included in the "General and administrative" line item in the unaudited statements of operations. The Company capitalizes a portion of stock-based compensation for employees who are directly involved in the acquisition of oil and natural gas properties into the full cost pool. Capitalized stock-based compensation is included in the "Oil and natural gas properties" line item on the unaudited balance sheets.

The 2018 Plan and 2013 Plan award types are summarized as follows:

Restricted Stock Awards

The Company issues restricted stock awards ("RSAs") subject to various vesting conditions as compensation to executive officers, employees and directors of the Company. RSAs issued to employees and executive officers generally vest over three years, provided that any performance and/or market conditions are also met. RSAs issued to directors generally vest over one year, provided that any performance and/or market conditions are also met. For RSAs subject to service and/or performance vesting conditions, the grant-date fair value is established based on the closing price of the Company's common stock on such date. Stock-based compensation expense for awards subject to only service conditions is recognized on a straight-line basis over the service period. Stock-based compensation expense for awards with both service and performance conditions is recognized on a graded basis only if it is probable that the performance condition will be achieved. The Company accounts for forfeitures of awards granted under these plans as they occur in determining stock-based compensation expense.

For awards subject to a market condition, the grant-date fair value is estimated using a Monte Carlo valuation model. The Company recognizes stock-based compensation expense for awards subject to market-based vesting conditions regardless of whether it becomes probable that these conditions will be achieved or not, and stock-based compensation expense for any such awards is not reversed if vesting does not actually occur. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility is calculated based on the historical volatility and implied volatility of the Company's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing these market-based awards were as follows:

| | 2019 |
|---|---|
| Risk-free interest rate | 2.57 % |
| Dividend yield | — % |
| Expected volatility | 85.00 % |
| Company's closing stock price on grant date | $ 2.71 |

During 2018, RSAs subject to service and performance-based vesting conditions were granted to employees and executive officers under the 2013 Plan. Vesting of these awards was contingent on the Company's annualized Adjusted EBITDA as compared to specified targets for the fourth quarter of 2018. The Company assessed the probability of achieving the performance condition throughout the performance period using its internal financial forecasts. The weighted average grant date fair value of these service and performance-based RSAs was $2.70 per share. Also during 2018, RSAs subject to service and market-based vesting conditions were granted to employees, executive officers, and directors under the 2013 Plan. Vesting of these awards was and is contingent on the Company's stock price performance relative to specified targets. The weighted average grant date fair value of these service and market-based RSAs was $1.67 per share.

During 2019, RSAs subject to service, market, and performance-based vesting conditions were granted to employees and executive officers under the 2018 Plan. Vesting of these awards is contingent on the Company's debt-adjusted cash flow per share as compared to specified targets. The weighted average grant date fair value of these service, performance, and market-based RSAs was $0.98 per share. Also during 2019, RSAs subject to service and market-based vesting conditions were granted to employees, executive officers, and directors under the 2018 Plan. Vesting of these awards is contingent on the Company's stock price performance relative to specified targets. The weighted average grant date fair value of these service and market-based RSAs was $1.82 per share.

The following table reflects the outstanding RSAs and activity related thereto for the nine months ended September 30, 2019:

| | Service-based Awards | | Service and Performance-based Awards | | Service and Market-based Awards | | Service, Performance, and Market-based Awards | |
|---|---|---|---|---|---|---|---|---|
| | Number of Shares | Weighted-average Grant Date Fair Value | Number of Shares | Weighted-average Grant Date Fair Value | Number of Shares | Weighted-average Grant Date Fair Value | Number of Shares | Weighted-average Grant Date Fair Value |
| Outstanding at December 31, 2018 | 632,759 | $ 2.72 | 1,018,500 | $ 2.70 | 1,176,600 | $ 1.67 | — | $ — |
| Shares granted | 847,200 | 2.71 | — | — | 1,254,000 | 1.82 | 1,068,000 | 0.98 |
| Shares forfeited | (32,402) | 2.76 | (4,000) | 2.70 | (416,033) | 1.68 | — | — |
| Shares vested | (896,221) | 2.82 | (639,500) | 2.70 | (264,203) | 1.67 | — | — |
| Outstanding at September 30, 2019 | 551,336 | $ 2.56 | 375,000 | $ 2.70 | 1,750,364 | $ 1.78 | 1,068,000 | $ 0.98 |

At September 30, 2019, there was $3.1 million of total unrecognized compensation expense related to unvested RSAs. That cost is expected to be recognized over a weighted average period of 0.6 years. For the nine months ended September 30, 2019 and 2018, the total fair value of the Company's restricted stock awards vested was $3.9 million and $3.1 million, respectively.

The following has been recorded to stock-based compensation expense for the periods presented:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| *(In thousands)* | 2019 | 2018 | 2019 | 2018 |
| Restricted stock award compensation | $ (8) | $ 1,655 | $ 4,577 | $ 2,342 |
| Less amounts capitalized in oil and natural gas properties | (106) | (142) | (296) | (250) |
| Total stock-based compensation, net | $ (114) | $ 1,513 | $ 4,280 | $ 2,092 |

## NOTE 7 RELATED PARTY TRANSACTIONS

In January 2019, the Company repurchased 3.7 million shares of Company common stock from W Energy Partners LLC ("W Energy") for cash consideration of $11.1 million. The repurchased shares were originally issued by the Company as partial consideration for the W Energy Acquisition described in Note 3 above. W Energy beneficially owned in excess of 5% of the Company's outstanding common stock at the time of the repurchase transaction.

The Company's Audit Committee is responsible for approving all transactions involving related parties, including the transaction identified above.

## NOTE 8 COMMITMENTS & CONTINGENCIES

Litigation

The Company is engaged in various proceedings incidental to the normal course of business. Due to their nature, such legal proceedings involve inherent uncertainties, including but not limited to, court rulings, negotiations between affected parties and governmental intervention. Based upon the information available to the Company and discussions with legal counsel, it is the Company's opinion that the outcome of the various legal actions and claims that are incidental to its business will not have a material impact on the Company's financial position, results of operations or cash flows. Such matters, however, are subject to many uncertainties, and the outcome of any matter is not predictable with assurance.

The Company's interests in certain crude oil and natural gas leases from the State of North Dakota are subject to an ongoing dispute over the ownership of minerals underlying the bed of the Missouri River within the boundaries of the Fort Berthold Reservation. The ongoing dispute is between the State of North Dakota and three affiliated tribes, both of whom have purported to lease mineral rights in tracts of riverbed within the reservation boundaries. In the event the ongoing dispute results in a final judgment that is adverse to the Company's interests, the Company would be required to reverse approximately $4.8 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 $4.8

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.

## 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. Due to uncertainty surrounding the realization of its deferred tax assets, the Company has continued to record a valuation allowance against its net deferred tax assets.

The income tax provision (benefit) for the three and nine months ended September 30, 2019 and 2018 consists of the following:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| ***(In thousands)*** | **2019** | **2018** | **2019** | **2018** |
| Current Income Tax Provision (Benefit) | $ — | $ — | $ — | $ — |
| Deferred Income Tax Provision (Benefit) | | | | |
| Federal | 19,328 | 3,812 | 6,431 | (14,748) |
| State | 4,248 | 840 | 1,420 | (3,251) |
| Valuation Allowance | (23,576) | (4,652) | (7,851) | 17,999 |
| Total Income Tax Provision (Benefit) | $ — | $ — | $ — | $ — |

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 and nine months ended September 30, 2019, differs 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 2019 and 2018 relates to the valuation allowance placed on the net deferred tax assets, in addition to state income taxes and estimated permanent differences.

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. During 2019, in evaluating whether it was more likely than not that the Company’s net deferred tax assets were realized through future net income, management considered all available positive and negative evidence, including (i) its earnings history, (ii) its ability to recover net operating loss carry-forwards, (iii) the projected future income and results of operations, and (iv) its ability to use tax planning strategies. Based on all the evidence available, management determined it was more likely than not that the net deferred tax assets, other than the deferred tax asset related to the Company’s alternative minimum tax credit, were not realizable, therefore a valuation allowance of $115.9 million was recorded at September 30, 2019.

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 and nine months ended September 30, 2019 and 2018, 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 sheets at September 30, 2019 and 2018 relating to unrecognized benefits.

**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 September 30, 2019 Using | | |
|---|---|---|---|
| *(In thousands)* | 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 price and basis swaps) | $ — | $ 62,531 | $ — |
| Commodity Derivatives – Noncurrent Asset (crude oil price and basis swaps and crude oil price swaptions) | — | 42,682 | — |
| Contingent Consideration – Current Liabilities | — | — | (10,058) |
| Total | $ — | $ 105,214 | $ (10,058) |

| | Fair Value Measurements at December 31, 2018 Using | | |
|---|---|---|---|
| *(In thousands)* | 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 price and basis swaps) | $ — | $ 115,870 | $ — |
| Commodity Derivatives – Noncurrent Asset (crude oil price swaps) | — | 61,843 | — |
| Contingent Consideration – Current Liabilities | — | — | (58,069) |
| Debt Exchange Derivatives – Current Liabilities | — | — | (18,183) |
| Total | $ — | $ 177,713 | $ (76,252) |

***Commodity Derivatives.*** The Level 2 instruments presented in the tables above consist of commodity derivative instruments (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.

***Contingent Consideration.*** The fair value of the contingent consideration potentially payable by the Company in connection with both the Pivotal Acquisition and W Energy Acquisition, which in certain circumstances the Company is permitted to settle in either cash or shares of common stock, was determined using Monte Carlo simulation models. Significant inputs used in the fair value measurements include (i) the Company's common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) volatility of the Company's common stock, and (iv) expected average daily trading volumes. The expected volatility and average daily trading volumes used in the valuation were unobservable in the marketplace and significant to the valuation methodology, and the contingent consideration's fair value was therefore designated as Level 3 in the valuation hierarchy. Changes in the fair value of this liability is included in other income (expense) in the Company's condensed statements of operations.

***Debt Exchange Derivatives.*** During the second and third quarters of 2018, the Company entered into and closed a number of independent, separately negotiated exchange agreements with holders of the Company's previously outstanding Unsecured Notes. Pursuant to each such exchange agreement, the Company agreed to issue the holder shares of its common stock in exchange for certain Unsecured Notes held by such holder. The Company had embedded derivatives related to certain of these exchange agreements that contained provisions whereby if at the end of the applicable restricted sale period the Company's common stock trades below specified levels, the Company may be required to pay additional consideration to the holder in the form of cash or additional shares of common stock. The Company determined these provisions were not clearly and closely related to the shares of common stock issued under the exchange agreements and, therefore, bifurcated these embedded features and reflected them at fair value in the financial statements. Prior to their settlements, the fair values of these embedded derivatives were determined using Monte Carlo simulations which considered various inputs including (i) the Company's common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) volatility of the Company's common stock, and (iv) expected average daily trading volumes. The expected volatility and average daily trading volumes used in the valuation were unobservable in the marketplace and significant to the valuation methodology, and the embedded derivatives' fair value was therefore designated as Level 3 in the valuation hierarchy. Changes in the fair values of these liabilities are included in other income (expense) in the Company's condensed statements of operations. As of September 30, 2019, there were no remaining outstanding debt exchange derivative liabilities.

The following table summarizes the changes in fair value of the Company's financial instruments classified as Level 3 in the fair value hierarchy:

| ***(In thousands)*** | | **Nine Months Ended September 30, 2019** |
|---|---|---|
| Beginning Balance | $ | (76,252) |
| Debt exchange derivative liability settlements | | 16,793 |
| Change in fair value of debt exchange derivative liability | | 1,390 |
| Contingent consideration settlements[1] | | 76,644 |
| Change in fair value of contingent consideration | | (28,633) |
| Ending Balance | $ | (10,058) |

[1] Includes $7.9 million of contingent consideration settlements included in accounts payable at September 30, 2019.

Fair Value of Other Financial Instruments

The carrying amounts of cash equivalents, receivables and payables approximate fair value due to the highly liquid or short-term nature of these instruments.

The carrying amount of the Company's long-term debt reported in the condensed balance sheet at September 30, 2019 is $1,140.1 million, which includes $684.5 million of second lien notes, $327.0 million of borrowings under the Company's Revolving Credit Facility and $128.6 million of Unsecured VEN Bakken Note (See Note 4). The fair value of the Company's second lien notes, which are publicly traded ("Level 1"), is $709.1 million at September 30, 2019. The Company's Revolving Credit Facility approximates its fair value because of its floating rate structure.

Non-Financial Assets and Liabilities

The Company estimates asset retirement obligations pursuant to the provisions of ASC 410. The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and natural gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligations liability is deemed to use Level 3 inputs. Asset retirement obligations incurred and acquired during the nine months ended September 30, 2019 were approximately $3.7 million.

The Company accounts for acquisitions of oil and natural gas properties under the acquisition method of accounting. Accordingly, the Company conducts assessments of net assets acquired and recognizes amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisitions are expensed as incurred. The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair value of oil and natural gas properties. The fair value of these properties is measured using a discounted cash flow model that converts future cash flows to a single discounted amount. These assumptions represent Level 3 inputs under the fair value hierarchy.

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 nine months ended September 30, 2019.

**NOTE 11 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT**

The Company utilizes commodity price swaps, basis swaps, swaptions and collars (purchased put options and written call options) to (i) reduce the effects of volatility in price changes on the crude oil commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending.

All derivative instruments are recorded on the Company's balance sheet as either assets or liabilities measured at their fair value (see Note 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.

| (In thousands) | Three Months Ended September 30, 2019 | Three Months Ended September 30, 2018 | Nine Months Ended September 30, 2019 | Nine Months Ended September 30, 2018 |
|---|---|---|---|---|
| Cash Received (Paid) on Settled Derivatives[(1)] | $ 18,386 | $ (12,923) | $ 35,666 | $ (33,320) |
| Non-Cash Mark-to-Market Gain (Loss) on Derivatives | 57,506 | (30,225) | (62,806) | (72,303) |
| Gain (Loss) on Derivative Instruments, Net | $ 75,892 | $ (43,148) | $ (27,139) | $ (105,622) |

(1) The three and nine months ended September 30, 2019, includes approximately $7.4 million of net cash proceeds from crude oil derivative contracts that were restructured in the third quarter of 2019 prior to their contractual maturities.

The Company has master netting agreements on individual commodity contracts with certain counterparties and therefore the current asset and liability are netted on the balance sheet and the non-current asset and liability are netted on the balance sheet for contracts with these counterparties.

As of September 30, 2019, the Company had a total volume on open commodity price swaps of 19.0 million barrels at a weighted average price of approximately $57.32 per barrel. The following table reflects the weighted average price of open commodity price swap derivative contracts as of September 30, 2019, by year with associated volumes.

| Year | Volumes (Bbl) | Weighted Average Price ($) |
|---|---|---|
| 2019 | 2,460,411 | $ 58.96 |
| 2020 | 9,427,594 | 58.53 |
| 2021 | 5,740,924 | 55.76 |
| 2022[(1)] | 1,372,866 | 52.57 |

(1) The Company has entered into crude oil derivative contracts that give counterparties the option to extend certain current derivative contracts for additional periods. Options covering a notional volume of 2.0 million barrels for 2022 are exercisable on or about December 31, 2021. If the counterparties exercise all such options, the notional volume of the Company's existing crude oil derivative contracts will increase by 2.0 million barrels at a weighted average price of $54.84 per barrel for 2022.

In addition to the open commodity price swap contracts the Company has entered into basis swap contracts. Basis swaps fix the price differential between a published index price and the applicable local index price under which the Company's production is sold. The following table reflects open commodity basis swap contracts as of September 30, 2019.

| Settlement Period | Total Volumes (Bbls) | Weighted Average Differential ($/Bbl) |
|---|---|---|
| 10/01/19 – 12/31/19 | 920,000 | $ (2.41) |

The following table sets forth the amounts, on a gross basis, and classification of the Company's outstanding derivative financial instruments at September 30, 2019 and December 31, 2018, 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 | September 30, 2019 Estimated Fair Value | December 31, 2018 Estimated Fair Value |
|---|---|---|---|
| Derivative Assets: | | *(In thousands)* | |
| Price Swap Contracts | Current Assets | $ 65,018 | $ 108,514 |
| Basis Swap Contracts | Current Assets | — | 7,356 |
| Price Swap Contracts | Noncurrent Assets | 51,937 | 61,843 |
| Total Derivative Assets | | $ 116,954 | $ 177,713 |
| | | | |
| Derivative Liabilities: | | | |
| Price Swap Contracts | Current Liabilities | $ (2,486) | $ — |
| Price Swap Contracts | Noncurrent Liabilities | (653) | — |
| Price Swaptions Contracts | Noncurrent Liabilities | (8,601) | — |
| Total Derivative Liabilities | | $ (11,741) | $ — |

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 September 30, 2019 | | |
|---|---|---|---|
| *(In thousands)* | 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 | $ 65,018 | $ (2,486) | $ 62,531 |
| Noncurrent Assets | 51,937 | (9,254) | 42,682 |
| Total Derivative Assets | $ 116,954 | $ (11,741) | $ 105,213 |
| | | | |
| Offsetting of Derivative Liabilities: | | | |
| Current Liabilities | $ (2,486) | $ 2,486 | $ — |
| Noncurrent Liabilities | (9,254) | 9,254 | — |
| Total Derivative Liabilities | $ (11,741) | $ 11,741 | $ — |

| | Estimated Fair Value at December 31, 2018 | | |
|---|---|---|---|
| *(In thousands)* | 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 | $ 116,620 | $ (750) | $ 115,870 |
| Non-Current Assets | 61,857 | (14) | 61,843 |
| Total Derivative Assets | $ 178,477 | $ (764) | $ 177,713 |
| | | | |
| Offsetting of Derivative Liabilities: | | | |
| Current Liabilities | $ (750) | $ 750 | $ — |
| Non-Current Liabilities | (14) | 14 | — |
| Total Derivative Liabilities | $ (764) | $ 764 | $ — |

All of the Company's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements ("ISDAs") entered into with parties that are also lenders under the Company's Revolving Credit Facility. The Company's obligations under the derivative instruments are secured pursuant to the Revolving Credit Facility, and no additional collateral had been posted by the Company as of September 30, 2019. 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 September 30, 2019 and December 31, 2018.

**NOTE 12 SUBSEQUENT EVENTS**

Amendment to Revolving Credit Facility

On November 8, 2019, the Company entered into an amendment (the "Amendment") to its amended and restated credit agreement, dated October 5, 2018 (the "Credit Agreement"), governing the Company's Revolving Credit Facility. Pursuant to the Amendment, the Credit Agreement has been amended to (i) adjust the maximum ratio of total net debt to EBITDAX (as defined in the Credit Agreement) that the Company is permitted to maintain as of the end of any fiscal quarter to 3.75 to 1.00, and (ii) adjust the minimum current ratio (as defined in the Credit Agreement) that the Company is required to maintain as follows: 0.85 to 1.00 as of September 30, 2019; 0.65 to 1.00 as of December 31, 2019; 0.90 to 1.00 as of March 31, 2020; and 1.00 to 1.00 as of any subsequent fiscal quarter end.

**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," "continue," "anticipate," "target," "could," "plan," "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 current properties, our ability to acquire additional development opportunities, changes in our reserves estimates or the value thereof, general economic or industry conditions, nationally and/or in the communities in which our company conducts business, changes in the interest rate environment, legislation or regulatory requirements, conditions of the securities markets, our ability to raise or access capital, changes in accounting principles, policies or guidelines, financial or political instability, acts of war or terrorism, and other economic, competitive, governmental, regulatory and technical factors affecting our company's operations, products and prices.

We have based any forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, results 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, 2018, 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. We do not undertake, and specifically disclaim, 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 provide us with drilling and development opportunities that will result in significant long-term value. Our primary focus is oil exploration and production through non-operated working interests in wells drilled and completed in spacing units that include our acreage. Using this strategy, we had participated in 6,024 gross (444.0 net) producing wells as of September 30, 2019.

On July 1, 2019, we closed on an acquisition of approximately 90.1 net producing wells and 3.3 net wells in process, as well as approximately 18,000 net acres in North Dakota, from VEN Bakken, LLC (the "VEN Bakken Acquisition"). We paid a combination of cash, equity and debt consideration, which we estimated to have a combined fair value of $312.4 million at closing. We estimate that this acquisition contributed approximately 17%, or approximately 6,949 Boe per day, of our average daily production in the third quarter of 2019.

Our average daily production in the third quarter of 2019 was approximately 40,786 Boe per day, of which approximately 80% was oil. Our recent acquisitions, combined with higher activity levels, have boosted our development levels and resulted in production in the third quarter of 2019 increasing by approximately 53% over the same period last year.

During the three months ended September 30, 2019, we added 198 gross (13.3 net) wells to production, in addition to the wells added at closing from the VEN Bakken Acquisition. As of September 30, 2019, we had leased approximately 183,518 net acres, of which approximately 89% were developed and substantially all were located in the Williston Basin in North Dakota and Montana.

**Source of Our Revenues**

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

**Principal Components of Our Cost Structure**

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

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

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

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

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

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

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

- *Income tax expense.* Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP, which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

**Selected Factors That Affect Our Operating Results**

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

- the timing and success of drilling and production activities by our operating partners;
- the prices and the supply and demand for oil, natural gas and NGLs;
- the quantity of oil and natural gas production from the wells in which we participate;
- changes in the fair value of the derivative instruments we use to reduce our exposure to fluctuations in the price of oil;
- our ability to continue to identify and acquire high-quality acreage and drilling opportunities; and
- the level of our operating expenses.

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

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

The price at which our oil production is sold typically reflects a discount to the NYMEX benchmark price. Thus, our operating results are also affected by changes in the oil price differentials between the NYMEX and the sales prices we receive for our oil production. Our oil price differential to the NYMEX benchmark price during the third quarter of 2019 was $5.48 per barrel, as compared to $4.16 per barrel in the third quarter of 2018. 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 can vary significantly, driven in part by volatility in oil prices that can substantially impact 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). During the first nine months of 2019, the weighted average authorization for expenditure (or AFE) cost for wells we elected to participate in was $7.9 million, compared to $8.1 million for the wells we elected to participate in during 2018.

**Market Conditions**

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

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the three and nine months ended September 30, 2019 and 2018.

| | Three Months Ended September 30, | |
|---|---|---|
| | 2019 | 2018 |
| Average NYMEX Prices[1] | | |
| Natural Gas (per Mcf) | $ 2.38 | $ 2.93 |
| Oil (per Bbl) | $ 56.41 | $ 69.61 |

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2019 | 2018 |
| Average NYMEX Prices[1] | | |
| Natural Gas (per Mcf) | $ 2.62 | $ 2.95 |
| Oil (per Bbl) | $ 57.08 | $ 66.87 |

(1) Based on average NYMEX closing prices.

For the three months ended September 30, 2019, the average NYMEX pricing was $56.41 per barrel of oil or 19% lower than the average NYMEX price per barrel for the comparable period in 2018. Our realized oil price after reflecting settled derivatives was 4% lower in the third quarter of 2019 than in the third quarter of 2018 due to the aforementioned lower average NYMEX price per barrel and a higher oil price differential, which was partially offset by a 2% increase in the average price of our settled derivatives per barrel.

As of September 30, 2019, we had a total volume on open commodity price swaps of 19.0 million barrels at a weighted average price of approximately $57.32 per barrel (see Note 11 to the condensed financial statements).

**Results of Operations for the Three Months Ended September 30, 2019 and September 30, 2018**

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

| | Three Months Ended September 30, | | |
|---|---|---|---|
| | 2019 | 2018 | % Change |
| **Net Production:** | | | |
| Oil (Bbl) | 3,002,789 | 2,064,092 | 45 % |
| Natural Gas and NGLs (Mcf) | 4,496,860 | 2,358,162 | 91 % |
| Total (Boe) | 3,752,266 | 2,457,119 | 53 % |
| | | | |
| **Net Sales (in thousands):** | | | |
| Oil Sales | $ 152,836 | $ 135,006 | 13 % |
| Natural Gas and NGL Sales | 5,153 | 10,409 | (51) % |
| Gain (Loss) on Settled Derivatives | 18,386 | (12,923) | |
| Gain (Loss) on Mark-to-Market of Derivative Instruments | 57,506 | (30,225) | |
| Other Revenue | 3 | 3 | |
| Total Revenues | 233,883 | 102,269 | 129 % |
| | | | |
| **Average Sales Prices:** | | | |
| Oil (per Bbl) | $ 50.90 | $ 65.45 | (22) % |
| Effect of Gain (Loss) on Settled Derivatives on Average Price (per Bbl) | 6.12 | (6.26) | |
| Oil Net of Settled Derivatives (per Bbl) | 57.02 | 59.19 | (4) % |
| Natural Gas and NGLs (per Mcf) | 1.15 | 4.41 | (74) % |
| Realized Price on a Boe Basis Including All Realized Derivative Settlements | 47.00 | 53.96 | (13) % |
| | | | |
| **Operating Expenses (in thousands):** | | | |
| Production Expenses | $ 32,347 | $ 18,161 | 78 % |
| Production Taxes | 15,391 | 13,579 | 13 % |
| General and Administrative Expenses | 4,206 | 4,674 | (10) % |
| Depletion, Depreciation, Amortization and Accretion | 55,566 | 30,258 | 84 % |
| | | | |
| **Costs and Expenses (per Boe):** | | | |
| Production Expenses | $ 8.62 | $ 7.39 | 17 % |
| Production Taxes | 4.10 | 5.53 | (26) % |
| General and Administrative Expenses | 1.12 | 1.90 | (41) % |
| Depletion, Depreciation, Amortization and Accretion | 14.81 | 12.31 | 20 % |
| | | | |
| **Net Producing Wells at Period End** | 444.0 | 284.3 | 56 % |

*Oil and Natural Gas Sales*

In the third quarter of 2019, our oil, natural gas and NGL sales, excluding the effect of settled derivatives, increased 9% as compared to the third quarter of 2018, driven by a 53% increase in production, which was partially offset by a 29% decrease in realized prices, excluding the effect of settled derivatives. The lower average realized price in the third quarter of 2019 as compared to the same period in 2018 was driven by lower average NYMEX oil and natural gas prices and a higher oil price differential. Oil price differential during the third quarter of 2019 was $5.48 per barrel, as compared to $4.16 per barrel in the third quarter of 2018. In addition, due to gas processing constraints and lower NGL prices, our average realized price for natural gas and NGLs was 74% lower in the third quarter of 2019 compared to the third quarter of 2018.

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. Our substantial acquisition activities (see Note 3 to our condensed financial statements) combined with increased development activity and improved performance from enhanced completion techniques helped drive a 53% increase in production levels in the third quarter of 2019 compared to the same period in 2018. These factors were partially offset by curtailments, shut-ins and completion delays due to infrastructure constraints that negatively impacted our production in the third quarter of 2019.

*Derivative Instruments*

We enter into derivative instruments to manage the price risk attributable to future oil production. Our gain (loss) on derivative instruments, net, was a gain of $75.9 million in the third quarter of 2019, compared to a loss of $43.1 million in the third quarter of 2018. 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 third quarter of 2019, we realized a gain on settled derivatives of $18.4 million, compared to a $12.9 million loss in the third quarter of 2018. The increase in the gain on settled derivatives was primarily due to an increase in our average settlement price, and a decrease in the average NYMEX oil price, in the third quarter of 2019 compared to the same period of 2018. During the third quarter of 2019, our derivative settlements included 2.4 million barrels of oil at an average settlement price of $61.89 per barrel, and an additional $7.4 million of net cash proceeds from crude oil derivative contracts that were restructured prior to their contractual maturities. During the third quarter of 2018 our derivative settlements included 1.5 million barrels of oil at an average settlement price of $60.62 per barrel. The average NYMEX oil price for the third quarter of 2019 was $56.41 compared to $69.61 for the third quarter of 2018.

Mark-to-market derivative gains and losses was a gain of $57.5 million in the third quarter of 2019, compared to a loss of $30.2 million in the third quarter of 2018. 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, while any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At September 30, 2019, all of our derivative contracts are recorded at their fair value, which was a net asset of $105.2 million, a decrease of $72.5 million from the $177.7 million net asset recorded as of December 31, 2018. The decrease in the net asset at September 30, 2019 as compared to December 31, 2018 was primarily due to changes in forward oil prices relative to prices on our open oil derivative contracts since December 31, 2018.

*Production Expenses*

Production expenses were $32.3 million in the third quarter of 2019, compared to $18.2 million in the third quarter of 2018. On a per unit basis, production expenses increased from $7.39 per Boe in the third quarter of 2018 to $8.62 per Boe in the third quarter of 2019. On an absolute dollar basis, the increase in our production expenses in the third quarter of 2019, as compared to the third quarter of 2018, was primarily due to a 53% increase in production, as well as a 56% increase in the total number of net producing wells. The increase in production expenses on a per unit basis was due in part to production curtailments and shut-ins that negatively impacted our production in the third quarter of 2019.

*Production Taxes*

We pay production taxes based on realized oil and natural gas sales. Production taxes were $15.4 million in the third quarter of 2019 compared to $13.6 million in the third quarter of 2018. The increase is due to higher production levels (partially offset by a decrease in realized prices), which increased our oil and natural gas sales in the third quarter of 2019 as compared to the third quarter of 2018. As a percentage of oil and natural gas sales, our production taxes were 9.7% and 9.3% in the third quarter of 2019 and 2018, respectively. The increase in our production taxes as a percentage of oil and natural gas sales is due to a higher mix of oil sales as a percentage of total oil and natural gas sales.

*General and Administrative Expenses*

General and administrative expenses were $4.2 million in the third quarter of 2019 compared to $4.7 million in the third quarter of 2018. The decrease was primarily due to a $1.6 million decrease in non-cash compensation expense, primarily due to the reversal of non-cash compensation expense in connection with the departure of an executive officer, partially offset by a $1.3 million dollar advisory fee paid in the third quarter of 2019 in connection with the closing of the VEN Bakken Acquisition.

*Depletion, Depreciation, Amortization and Accretion*

Depletion, depreciation, amortization and accretion ("DD&A") was $55.6 million in the third quarter of 2019, compared to $30.3 million in the third quarter of 2018. Depletion expense, the largest component of DD&A, increased by $25.2 million in the third quarter of 2019 compared to the third quarter of 2018. The aggregate increase in depletion expense was driven by a 53% increase in production levels and a 20% increase in the depletion rate per Boe. On a per unit basis, depletion expense was $14.72 per Boe in the third quarter of 2019 compared to $12.23 per Boe in the third quarter of 2018. The higher depletion rate per Boe was primarily driven by the impact of recent acquisitions. Depreciation, amortization and accretion was $0.3 million and $0.2 million in the third quarter of 2019 and 2018, respectively. The following table summarizes DD&A expense per Boe for the third quarter of 2019 and 2018:

| | Three Months Ended September 30, | | | |
|---|---|---|---|---|
| | **2019** | **2018** | **$ Change** | **% Change** |
| Depletion | $ 14.72 | $ 12.23 | $ 2.49 | 20 % |
| Depreciation, Amortization and Accretion | 0.09 | 0.08 | 0.01 | 13 % |
| Total DD&A Expense | $ 14.81 | $ 12.31 | $ 2.50 | 20 % |

*Interest Expense*

Interest expense, net of capitalized interest, was $21.5 million for the third quarter of 2019 compared to $20.4 million in the third quarter of 2018. The increase in interest expense was primarily due to higher levels of debt outstanding in the third quarter of 2019 compared to the third quarter of 2018.

*Debt Exchange Derivative Gain (Loss)*

As a result of certain debt exchange agreements that were entered into during 2018 (see Note 10 to our condensed financial statements), we incurred debt exchange derivative liabilities during 2018. For the third quarter of 2019, we recorded a debt exchange derivative loss of $0.02 million due to a change in the fair value of these liabilities during the third quarter of 2019 compared to a gain of $13.1 million in the third quarter of 2018 (see Note 10 to our condensed financial statements). As of September 30, 2019, we had no debt exchange derivative liabilities remaining.

*Contingent Consideration Gain (Loss)*

In connection with the W Energy Acquisition and the Pivotal Acquisition in 2018 (see Note 3 to our condensed financial statements), we incurred contingent consideration liabilities during 2018. During the third quarter of 2019, we recorded a contingent consideration loss of $5.3 million due to a change in the fair value of these liabilities (see Note 10 to our condensed financial statements). There was no contingent consideration gain (loss) in the third quarter of 2018, since the relevant agreements were not yet in place.

*Income Tax*

During the third quarter of 2019 and 2018, 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 condensed financial statements.

We intend to continue to maintain a full valuation allowance on our deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of this allowance. However, sufficient positive evidence may become available to allow us to reach a conclusion that a portion of the valuation allowance will no longer be needed. Release of any portion of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense for the period the release is recorded.

**Results of Operations for the Nine Months Ended September 30, 2019 and September 30, 2018**

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

| | Nine Months Ended September 30, | | |
|---|---|---|---|
| | 2019 | 2018 | % Change |
| **Net Production:** | | | |
| Oil (Bbl) | 8,106,534 | 5,044,482 | 61 % |
| Natural Gas and NGLs (Mcf) | 11,648,580 | 5,684,327 | 105 % |
| Total (Boe) | 10,047,964 | 5,991,870 | 68 % |
| | | | |
| **Net Sales (in thousands):** | | | |
| Oil Sales | $ 416,259 | $ 315,186 | 32 % |
| Natural Gas and NGL Sales | 24,260 | 26,157 | (7) % |
| Gain (Loss) on Settled Derivatives | 35,666 | (33,320) | |
| Loss on Mark-to-Market of Derivative Instruments | (62,806) | (72,303) | |
| Other Revenue | 10 | 8 | |
| Total Revenues | 413,389 | 235,729 | 75 % |
| | | | |
| **Average Sales Prices:** | | | |
| Oil (per Bbl) | $ 51.35 | $ 62.54 | (18) % |
| Effect of Gain (Loss) on Settled Derivatives on Average Price (per Bbl) | 4.40 | (6.61) | |
| Oil Net of Settled Derivatives (per Bbl) | 55.75 | 55.93 | — % |
| Natural Gas and NGLs (per Mcf) | 2.08 | 4.60 | (55) % |
| Realized Price on a Boe Basis Including All Realized Derivative Settlements | 47.39 | 51.45 | (8) % |
| | | | |
| **Operating Expenses (in thousands):** | | | |
| Production Expenses | $ 83,146 | $ 45,198 | 84 % |
| Production Taxes | 41,944 | 31,633 | 33 % |
| General and Administrative Expenses | 15,506 | 9,593 | 62 % |
| Depletion, Depreciation, Amortization and Accretion | 146,791 | 71,485 | 105 % |
| | | | |
| **Costs and Expenses (per Boe):** | | | |
| Production Expenses | $ 8.27 | $ 7.54 | 10 % |
| Production Taxes | 4.17 | 5.28 | (21) % |
| General and Administrative Expenses | 1.54 | 1.60 | (4) % |
| Depletion, Depreciation, Amortization and Accretion | 14.61 | 11.93 | 22 % |
| | | | |
| **Net Producing Wells at Period End** | 444.0 | 284.3 | 56 % |

*Oil and Natural Gas Sales*

In the first nine months of 2019, our oil, natural gas and NGL sales, excluding the effect of settled derivatives, increased 29% as compared to the first nine months of 2018, driven by a 68% increase in production, which was partially offset by a 23% decrease in realized prices, excluding the effect of settled derivatives. The lower average realized price in the first nine months of 2019 as compared to the same period in 2018 was driven by lower average NYMEX oil and natural gas prices and a higher oil price differential. Oil price differential during the first nine months of 2019 was $5.70 per barrel, as compared to $4.33 per barrel in the third quarter of 2018. In addition, due to gas processing constraints and lower NGL prices, our average realized price for natural gas and NGLs was 55% lower in the first nine months of 2019 compared to first nine months of 2018.

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. Our substantial acquisition activities (see Note 3 to our condensed financial statements) combined with increased development activity and improved performance from enhanced completion techniques helped drive a 68% increase in production levels in the first nine months of 2019 compared to the same period in 2018. These factors were partially offset by curtailments, shut-ins and completion delays due to infrastructure constraints that negatively impacted our production in the first nine months of 2019.

*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 $27.1 million in the first nine months of 2019, compared to a loss of $105.6 million in the first nine months of 2018. 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 nine months of 2019, we realized a gain on settled derivatives of $35.7 million, compared to a $33.3 million loss in the first nine months of 2018. The increase in the gain on settled derivatives was primarily due to an increase in our average settlement price, and a decrease in the average NYMEX oil price, in the first nine months of 2019 compared to the same period of 2018. During the first nine months of 2019, our derivative settlements included 6.1 million barrels of oil at an average settlement price of $62.53 per barrel, and an additional $7.4 million of net cash proceeds from crude oil derivative contracts that were restructured prior to their contractual maturities. During the first nine months of 2018 our derivative settlements included 3.2 million barrels of oil at an average settlement price of $56.69 per barrel. The average NYMEX oil price for the first nine months of 2019 was $57.08 compared to $66.87 for the first nine months of 2018.

Mark-to-market derivative gains and losses was a loss of $62.8 million in the first nine months of 2019, compared to a loss of $72.3 million in the first nine months of 2018. 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, while any losses are expected to be offset by higher future wellhead revenues based on the value at the settlement date. At September 30, 2019, all of our derivative contracts are recorded at their fair value, which was a net asset of $105.2 million, a decrease of $72.5 million from the $177.7 million net asset recorded as of December 31, 2018. The decrease in the net asset at September 30, 2019 as compared to December 31, 2018 was primarily due to changes in forward oil prices relative to prices on our open oil derivative contracts since December 31, 2018.

*Production Expenses*

Production expenses were $83.1 million in the first nine months of 2019, compared to $45.2 million in the first nine months of 2018. On a per unit basis, production expenses increased from $7.54 per Boe in the first nine months of 2018 to $8.27 per Boe in the first nine months of 2019. On an absolute dollar basis, the increase in our production expenses in the first nine months of 2019, as compared to the first nine months of 2018, was primarily due to a 68% increase in production, as well as a 56% increase in the total number of net producing wells, The increase in production expenses on a per unit basis was due in part to production curtailments and shut-ins that negatively impacted our production in the first nine months of 2019.

*Production Taxes*

We pay production taxes based on realized oil and natural gas sales. Production taxes were $41.9 million in the first nine months of 2019 compared to $31.6 million in the first nine months of 2018. The increase is due to higher production levels (partially offset by a decrease in realized prices), which increased our oil and natural gas sales in the first nine months of 2019 as compared to the first nine months of 2018. As a percentage of oil and natural gas sales, our production taxes were 9.5% and 9.3% in the first nine months of 2019 and 2018, respectively. The increase in our production taxes as a percentage of oil and natural gas sales is due to a greater portion of our oil and natural gas sales consisting of oil sales.

*General and Administrative Expenses*

General and administrative expenses were $15.5 million in the first nine months of 2019 compared to $9.6 million in the first nine months of 2018. The increase was primarily due to a $3.5 million increase in compensation expense, $2.3 million of which was increased non-cash compensation expense, primarily due to the additions to our executive team that occurred late in the second quarter of 2018 and the timing of our 2018 and 2019 performance-based equity awards. In addition, we had a $1.8 million of transaction costs in the first nine months of 2019 associated with the VEN Bakken Acquisition.

*Depletion, Depreciation, Amortization and Accretion*

DD&A was $146.8 million in the first nine months of 2019, compared to $71.5 million in the first nine months of 2018. Depletion expense, the largest component of DD&A, increased by $75.1 million in the first nine months of 2019 compared to the first nine months of 2018. The aggregate increase in depletion expense was driven by a 68% increase in production levels and a 23% increase in the depletion rate per Boe. On a per unit basis, depletion expense was $14.53 per Boe in the first nine months of 2019 compared to $11.83 per Boe in the first nine months of 2018. The higher depletion rate per Boe was primarily driven by the impact of recent acquisitions. Depreciation, amortization and accretion was $0.8 million and $0.6 million for the first nine months of 2019 and 2018, respectively. The following table summarizes DD&A expense per Boe for the first nine months of 2019 and 2018:

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2019 | 2018 | $ Change | % Change |
| Depletion | $ 14.53 | $ 11.83 | $ 2.70 | 23 % |
| Depreciation, Amortization and Accretion | 0.08 | 0.10 | (0.02) | (20) % |
| Total DD&A Expense | $ 14.61 | $ 11.93 | $ 2.68 | 22 % |

*Interest Expense*

Interest expense, net of capitalized interest, was $58.8 million for the first nine months of 2019 compared to $65.9 million in the first nine months of 2018. The decrease in interest expense was primarily due to lower interest rates on our Revolving Credit Facility in place for the first nine months of 2019 compared to our term loan credit facility that was in place for the first nine months of 2018.

*Debt Exchange Derivative Gain (Loss)*

As a result of certain debt exchange agreements that were entered into during 2018 (see Note 10 to our condensed financial statements), we incurred debt exchange derivative liabilities during 2018. For the first nine months of 2019, we recorded a debt exchange derivative gain of $1.4 million due to a change in the fair value of these liabilities during the first nine months of 2019 compared to a gain of $13.1 million during the first nine months of 2018 (see Note 10 to our condensed financial statements). As of September 30, 2019, we had no debt exchange derivative liabilities remaining.

*Contingent Consideration Gain (Loss)*

In connection with the W Energy Acquisition and the Pivotal Acquisition in 2018 (see Note 3 to our condensed financial statements), we incurred contingent consideration liabilities during 2018. During the first nine months of 2019, we recorded a contingent consideration loss of $28.6 million due to changes in the fair value of these liabilities (see Note 10 to our condensed financial statements). There was no contingent consideration gain (loss) in the first nine months of 2018, because the relevant agreements were not yet in place.

*Income Tax*

During the first nine months of 2019 and 2018, no income tax expense (benefit) was recorded on the income (loss) before income taxes due to uncertainty regarding the realization of our deferred tax assets. For further discussion of our valuation allowance, see Note 9 to our condensed financial statements.

We intend to continue maintaining a full valuation allowance on our deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of these allowances. However, sufficient positive evidence may become available to allow us to reach a conclusion that a portion of the valuation allowance will no longer be needed. Release of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense for the period the release is recorded.

**Non-GAAP Financial Measures**

We define Adjusted Net Income (Loss) as net income (loss) excluding (i) (gain) loss on the mark-to-market of derivative instruments, net of tax, (ii) impairment of other current assets, net of tax, (iii) loss on the extinguishment of debt, net of tax, (iv) debt exchange derivative (gain) loss, net of tax, (v) contingent consideration (gain) loss, net of tax, and (vi) certain acquisition transaction costs, net of tax. Our Adjusted Net Income for the third quarter of 2019 was $36.3 million or $0.09 per diluted share, compared to $34.5 million or $0.11 per diluted share for the third quarter of 2018. Our Adjusted Net Income for the first nine months of 2019 was $99.4 million or $0.26 per diluted share, compared to $63.9 million or $0.34 per diluted share for the first nine months of 2018. For both periods, the increase in Adjusted Net Income is primarily due to significantly higher production volumes as a result of our acquisitions and organic growth, which was partially offset by lower realized commodity prices (after the effect of settled derivatives) and increased per unit production expenses.

We define Adjusted EBITDA as net income (loss) before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization and accretion, (iv) impairment of other current assets, (v) non-cash stock-based compensation expense, (vi) loss on the extinguishment of debt, (vii) debt exchange derivative (gain) loss, (viii) contingent consideration (gain) loss, and (ix) (gain) loss on the mark-to-market of derivative instruments. Adjusted EBITDA for the third quarter of 2019 was $124.4 million, compared to Adjusted EBITDA of $97.9 million for the third quarter of 2018. Adjusted EBITDA for the first nine months of 2019 was $340.0 million, compared to Adjusted EBITDA of $224.4 million for the first nine months of 2018. In both periods, the increase in Adjusted EBITDA is primarily due to significantly higher production volumes as a result of our acquisitions and organic growth, which was partially offset by lower realized commodity prices (after the effect of settled derivatives) and increased per unit production expenses.

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

These measures should be considered in addition to our results of operations 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:

**Reconciliation of Adjusted Net Income**

| *(In thousands, except share and per share data)* | Three Months Ended September 30, 2019 | Three Months Ended September 30, 2018 | Nine Months Ended September 30, 2019 | Nine Months Ended September 30, 2018 |
|---|---|---|---|---|
| Net Income (Loss) | $ 94,381 | $ 18,979 | $ 31,619 | $ (74,603) |
| Add: | | | | |
| Impact of Selected Items: | | | | |
| (Gain) Loss on the Mark-to-Market of Derivative Instruments | (57,506) | 30,225 | 62,806 | 72,303 |
| Impairment of Other Current Assets | 5,275 | — | 7,969 | — |
| Loss on the Extinguishment of Debt | — | 9,542 | 425 | 100,375 |
| Debt Exchange Derivative (Gain) Loss | 23 | (13,063) | (1,390) | (13,063) |
| Contingent Consideration Loss | 5,262 | — | 28,633 | — |
| Acquisition Transaction Costs | 1,250 | — | 1,763 | — |
| Selected Items, Before Income Taxes | (45,696) | 26,705 | 100,204 | 159,615 |
| Income Tax of Selected Items(1) | (12,380) | (11,195) | (32,401) | (21,107) |
| Selected Items, Net of Income Taxes | (58,077) | 15,510 | 67,803 | 138,508 |
| | | | | |
| Adjusted Net Income | $ 36,304 | $ 34,489 | $ 99,422 | $ 63,905 |
| | | | | |
| Weighted Average Shares Outstanding – Basic | 396,044,887 | 300,517,497 | 374,927,630 | 188,152,998 |
| Weighted Average Shares Outstanding – Diluted | 396,530,767 | 301,755,419 | 375,736,820 | 188,709,068 |
| | | | | |
| Net Income (Loss) Per Common Share – Basic | $ 0.24 | $ 0.06 | $ 0.08 | $ (0.40) |
| Add: | | | | |
| Impact of Selected Items, Net of Income Taxes | (0.15) | 0.05 | 0.19 | 0.74 |
| Adjusted Net Income Per Common Share – Basic | $ 0.09 | $ 0.11 | $ 0.27 | $ 0.34 |
| | | | | |
| Net Income (Loss) Per Common Share – Diluted | $ 0.24 | $ 0.06 | $ 0.08 | $ (0.40) |
| Add: | | | | |
| Impact of Selected Items, Net of Income Taxes | (0.15) | 0.05 | 0.18 | 0.74 |
| Adjusted Net Income Per Common Share – Diluted | $ 0.09 | $ 0.11 | $ 0.26 | $ 0.34 |

(1) For the three and nine months ended September 30, 2019, this represents a tax impact using an estimated tax rate of 24.5%, which includes an adjustment of $23.6 million and $7.9 million, respectively, for a change in valuation allowance. For the three and nine months ended September 30, 2018, this represents a tax impact using an estimated tax rate of 24.5%, which includes an adjustment of $4.7 million and $18.0 million, respectively, for a change in valuation allowance.

**Reconciliation of Adjusted EBITDA**

| *(In thousands)* | Three Months Ended September 30, 2019 | Three Months Ended September 30, 2018 | Nine Months Ended September 30, 2019 | Nine Months Ended September 30, 2018 |
|---|---|---|---|---|
| Net Income (Loss) | $ 94,381 | $ 18,979 | $ 31,619 | $ (74,603) |
| Add: | | | | |
| Interest Expense | 21,510 | 20,438 | 58,836 | 65,948 |
| Income Tax Provision (Benefit) | — | — | — | — |
| Depreciation, Depletion, Amortization and Accretion | 55,566 | 30,258 | 146,791 | 71,485 |
| Impairment of Other Current Assets | 5,275 | — | 7,969 | — |
| Non-Cash Stock-Based Compensation | (114) | 1,535 | 4,280 | 1,973 |
| Loss on the Extinguishment of Debt | — | 9,542 | 425 | 100,375 |
| Debt Exchange Derivative (Gain) Loss | 23 | (13,063) | (1,390) | (13,063) |
| Contingent Consideration Loss | 5,262 | — | 28,633 | — |
| (Gain) Loss on the Mark-to-Market of Derivative Instruments | (57,506) | 30,225 | 62,806 | 72,303 |
| Adjusted EBITDA | $ 124,396 | $ 97,914 | $ 339,968 | $ 224,418 |

## Liquidity and Capital Resources

### *Overview*

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

On July 1, 2019, we closed on the VEN Bakken Acquisition, for which we paid total estimated consideration consisting of $172.1 million in cash, 5,602,147 shares of common stock and $130.0 million in principal amount of a newly issued 6.0% Senior Unsecured Promissory Note due 2022 (the "Unsecured VEN Bakken Note").

As of September 30, 2019, we had (i) long-term debt consisting of $327.0 million of borrowings under our Revolving Credit Facility, $688.5 million aggregate principal amount of Second Lien Notes and $130.0 million aggregate principal amount under the Unsecured VEN Bakken Note, and (ii) $99.9 million in liquidity, consisting of $98.0 million of borrowing base availability under our Revolving Credit Facility and $1.9 million of cash on hand.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility. Oil accounted for 80% and 84% of our total production volumes in the third quarter of 2019 and 2018, 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 seek to maintain a robust hedging program to mitigate volatility in the price of crude oil with respect to a portion of our expected oil production. In 2018, we hedged approximately 64% of our crude oil production and for the three months ended September 30, 2019, we hedged approximately 81% of our crude oil production. For a summary as of September 30, 2019, of our open commodity swap contracts for future periods, see "Item 3. Quantitative and Qualitative Disclosures about Market Risk" below.

With our cash on hand, cash flow from operations, and borrowing capacity under our Revolving Credit Facility, we believe that we will have sufficient cash flow and liquidity to fund our budgeted capital expenditures and operating expenses for at least the next twelve months. However, we may seek additional access to capital and liquidity. We cannot assure you, however, that any additional capital will be available to us on favorable terms or at all.

Our increase in production and higher commodity prices have increased our cash flow from operations, which exceeded our cash spend for drilling and development activities by $63.0 million for the nine months ended September 30, 2019, excluding cash paid for the acquisition of oil and natural gas properties. With higher production and the impact of recent acquisitions, we anticipate that we will continue to generate a cash flow surplus in future periods (excluding cash paid for any acquisitions).

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

### *Working Capital*

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

At September 30, 2019, we had a working capital deficit of $58.7 million, compared to a deficit of $3.1 million at December 31, 2018. Current assets decreased by $56.3 million and current liabilities decreased by $0.7 million at September 30, 2019, compared to December 31, 2018. The decrease in current assets is primarily due to a decrease in our derivative instruments of $53.3 million due to the change in fair value as a result of oil price projections. The change in current liabilities is due to a $64.6 million increase in our accounts payable and accrued liabilities primarily due to an increase in development activity, which was offset by a $48.0 million decrease in contingent consideration liabilities in connection with our Pivotal and W Energy Acquisitions (see Note 3 to our condensed financial statements), and a reduction in the debt exchange derivative liabilities of $18.2 million (see Note 10 to our condensed financial statements).

***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 our Revolving Credit Facility. As of September 30, 2019, we had entered into derivative swap contracts hedging 2.5 million barrels of oil for the remainder of 2019 at an average price of $58.96 per barrel, 9.4 million barrels of oil in 2020 at an average price of $58.53 per barrel, 5.7 million barrels of oil in 2021 at an average price of $55.76 per barrel, 1.4 million barrels of oil in 2022 at an average price of $52.57 per barrel.

Our cash flows for the nine months ended September 30, 2019 and 2018 are presented below:

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2019 | 2018 |
| | (in thousands, unaudited) | |
| Net Cash Provided by Operating Activities | $ 269,323 | $ 126,416 |
| Net Cash Used for Investing Activities | (417,948) | (310,090) |
| Net Cash Provided by Financing Activities | 148,169 | 194,457 |
| Net Change in Cash | $ (456) | $ 10,783 |

*Cash Flows from Operating Activities*

Net cash provided by operating activities for the nine months ended September 30, 2019 was $269.3 million, compared to $126.4 million in the same period of the prior year. This increase was due to higher production levels and lower interest costs partially offset by lower realized prices (including the effect of settled derivatives). 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 and other items (as reflected in our statements of cash flows) in the nine months ended September 30, 2019 was a decrease of $15.3 million compared to a decrease of $36.0 million in the same period of the prior year.

*Cash Flows from Investing Activities*

Cash flows used in investing activities during the nine months ended September 30, 2019 and 2018 were $417.9 million and $310.1 million, respectively. The increase in cash used in investing activities for the first nine months of 2019 as compared to the same period of 2018 was attributable to higher development spending and acquisitions. Additionally, the amount of capital expenditures included in accounts payable (and thus not included in cash flows from investing activities) was $178.8 million and $108.2 million at September 30, 2019 and 2018, 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 nine months ended September 30, 2019, our capitalized costs incurred for oil and natural gas properties (e.g., drilling and completion costs, acquisitions, and other capital expenditures) amounted to $619.3 million, while the actual cash spend in this regard amounted to $416.9 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 nine months ended September 30, 2019 and 2018 are summarized in the following table:

| | Nine Months Ended September 30, | |
|---|---|---|
| | **2019** | **2018** |
| | **(in millions, unaudited)** | |
| Drilling and Development Capital Expenditures | $ 205.4 | $ 164.1 |
| Acquisition of Oil and Natural Gas Properties | 210.6 | 125.5 |
| Other Capital Expenditures | 0.9 | 0.5 |
| Total | $ 416.9 | $ 290.1 |

*Cash Flows from Financing Activities*

Net cash provided by financing activities was $148.2 million during the nine months ended September 30, 2019, compared to cash provided by financing activities of $194.5 million during the nine months ended September 30, 2018. For the nine months ended September 30, 2019, cash provided by financing activities was primarily related to $187.0 million of net borrowing under the Revolving Credit Facility, which was partially offset by $15.1 million of common stock repurchases, $10.5 million in repurchases of Second Lien Notes and $12.3 million for settlements related to our contingent consideration and debt exchange derivative liabilities. For the nine months ended September 30, 2018, cash provided by financing activities was primarily related to the issuance of common stock of $141.7 million and borrowings under our prior term loan credit agreement of $60.0 million.

***Revolving Credit Facility***

In October 2018, we entered into a $750.0 million Revolving Credit Facility with Royal Bank of Canada, as administrative agent, and the lenders from time to time party thereto. The Revolving Credit Facility is subject to a borrowing base with maximum loan value to be assigned to the proved reserves attributable to our oil and gas properties. As of September 30, 2019, the Revolving Credit Facility had a borrowing base of $425.0 million and we had $327.0 million in borrowings outstanding under the facility, leaving $98.0 million in available borrowing capacity. See Note 4 to our condensed financial statements for further details regarding the Revolving Credit Facility.

***Second Lien Notes due 2023***

As of September 30, 2019, we had $688.5 million in outstanding principal amount of our 8.500% senior secured second lien notes due 2023. See Note 4 to our condensed financial statements for further details regarding the Second Lien Notes.

***Unsecured VEN Bakken Note***

As of September 30, 2019, we had $130.0 million in outstanding principal amount under the Unsecured VEN Bakken Note. See Note 4 to our condensed financial statements for further details regarding the Unsecured VEN Bakken Note.

***Effects of Inflation and Pricing***

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

***Contractual Obligations and Commitments***

Please see our disclosure of contractual obligations and commitments as of December 31, 2018, included in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2018.

***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, 2018.

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, 2018.

**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, 2018 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 we believe these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue generally would have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil that also increase and decrease along with oil prices.

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

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

The following table summarizes our open commodity swap contracts as of September 30, 2019, by fiscal quarter.

| Settlement Period | Oil (Barrels) | Weighted Average Price ($) |
|---|---|---|
| ***Swaps-Crude Oil*** | | |
| **2019:** | | |
| Q4 | 2,460,411 | $ 58.96 |
| **2020:** | | |
| Q1 | 2,490,106 | $ 59.15 |
| Q2 | 2,431,778 | 58.44 |
| Q3 | 2,340,348 | 58.48 |
| Q4 | 2,165,362 | 58.00 |
| **2021:** | | |
| Q1 | 1,600,050 | $ 56.78 |
| Q2 | 1,496,958 | 57.32 |
| Q3 | 1,326,410 | 54.25 |
| Q4 | 1,317,506 | 54.27 |
| **2022[(1)]:** | | |
| Q1 | 453,780 | $ 53.07 |
| Q2 | 312,280 | 52.30 |
| Q3 | 306,576 | 52.33 |
| Q4 | 300,230 | 52.35 |

(1) We have entered into crude oil derivative contracts that give counterparties the option to extend certain current derivative contracts for additional periods. Options covering a notional volume of 2.0 million barrels for 2022 are exercisable on or about December 31, 2021. If the counterparties exercise all such options, the notional volume of our existing crude oil derivative contracts will increase as follows for 2022: (i) for the first quarter of 2022, by 717,750 barrels at a weighted average price of $54.82 per barrel, (ii) for the second quarter of 2022, by 725,725 barrels at a weighted average price of $54.82 per barrel, (iii) for the third quarter of 2022, by 273,700 barrels at a weighted average price of $54.90 per barrel, and (iv) for the fourth quarter of 2022, by 273,700 barrels at a weighted average price of $54.90 per barrel.

In addition to the open commodity price swap contracts we have entered into basis swap contracts. Basis swaps fix the price differential between a published index price and the applicable local index price under which our production is sold. The following table reflects open commodity basis swap contracts as of September 30, 2019.

| Settlement Period | Total Volumes (Bbls) | Weighted Average Differential ($/Bbl) |
|---|---|---|
| 10/01/19 – 12/31/19 | 920,000 | $ (2.41) |

**Interest Rate Risk**

Our long-term debt as of September 30, 2019 is comprised of borrowings that contain fixed and floating interest rates. The Senior Secured Notes bear cash interest at an annual fixed rate of 8.5%, plus potential payment-in-kind (“PIK”) interest at an annual fixed rate (if owed) of 1.0%. Our Revolving Credit Facility interest rate is a floating rate option that is designated by us within the parameters established by the underlying agreement. At our option, borrowings under the Revolving Credit Facility bear interest at the base rate or LIBOR, plus an applicable margin. The base rate is a rate per annum equal to the greatest of: (i) the agent bank’s prime rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate for a one-month interest period plus 100 basis points. The applicable margin for base rate loans ranges from 75 to 175 basis points, and the applicable margin for LIBOR loans ranges from 175 to 275 basis points, in each case depending on the percentage of the borrowing base utilized. Interest payments are due under the Revolving Credit Facility in arrears, in the case of a loan based on LIBOR on the last day of the specified interest period and in the case of all other loans on the last day of each March, June, September and December. All outstanding principal is due and payable upon termination of the Revolving Credit Facility.

As a result, changes in interest rates can impact results of operations and cash flows. A 1% increase in short-term interest rates on our floating-rate debt outstanding at September 30, 2019 would cost us approximately $1.7 million in additional annual interest expense.

**Other Market Risk**

*Contingent Consideration*

As a result of both the W Energy Acquisition and the Pivotal Acquisition, both described in Note 3 to our condensed financial statements, we incurred liabilities related to the contingent consideration potentially payable by us. The amount of contingent consideration we are required to pay after September 30, 2019 is dependent on the average daily volume-weighted average price of our common stock for each month from July-October 2019 compared to specified monthly benchmarks in each applicable agreement.

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

The aggregate fair value of these remaining liabilities was $10.1 million as of September 30, 2019. The liability is highly sensitive to the price of our common stock at each valuation date.

See Note 3 and Note 10 to our condensed financial statements for additional information regarding these contingent consideration liabilities.

**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 September 30, 2019, 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 September 30, 2019.

**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 September 30, 2019, that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

## 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.

### 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, 2018.

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

**Recent Sales of Unregistered Securities**

As previously disclosed, during the second and third quarters of 2018, we entered into and closed ten independent, separately negotiated exchange agreements with holders of our previously outstanding 8.00% senior unsecured notes due 2020 (the "2020 Notes") pursuant to which, in total during 2018, we issued 32.8 million shares of common stock in exchange for $100.5 million in principal amount of the 2020 Notes.

Pursuant to the exchange agreements governing these exchanges, with limited exceptions, we subjected the holders to lock-up provisions restricting their ability to sell the shares of common stock issued to them. The periods during which the lock-up provisions were applicable were of varying lengths and subject to varying exceptions. Generally, if at the end of the applicable lock-up period, our common stock traded below specified levels, we were required to pay the applicable holder additional consideration either in the form of cash or additional shares of common stock, at our option. In settlement of such obligations, since June 30, 2019, we issued the following shares of common stock for no additional consideration on the dates indicated: July 3, 2019 – 370,303 shares; August 5, 2019 – 507,384 shares; September 5, 2019 – 1,107,843 shares; October 3, 2019 – 6,975 shares. We have no further obligation to issue securities under these exchange agreements.

The issuances of the shares of common stock described above were made in reliance on the exemption from registration provided in Section 3(a)(9) of the Securities Act.

**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 Exchange Act, of our common stock during the quarter ended September 30, 2019.

| 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 | | | | |
| July 1, 2019 to July 31, 2019 | — | $ — | — | $ 68.1 million |
| Month #2 | | | | |
| August 1, 2019 to August 31, 2019 | — | — | — | 68.1 million |
| Month #3 | | | | |
| September 1, 2019 to September 30, 2019 | — | — | — | 68.1 million |
| Total | — | $ — | — | $ 68.1 million |

(1) Represents shares surrendered in satisfaction of tax withholding obligations in connection with the vesting of restricted stock awards.

(2) In May 2011, our board of directors approved a stock repurchase program to acquire up to $150 million of shares of our 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.

**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 |
|---|---|---|
| 2.1 | Purchase and Sale Agreement, dated April 18, 2019, by and between Northern Oil and Gas, Inc. and VEN Bakken, LLC | Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the SEC on April 22, 2019 |
| 3.1 | Restated Certificate of Incorporation of Northern Oil and Gas, Inc. dated August 24, 2018 | Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 27, 2018 |
| 3.2 | By-Laws of Northern Oil and Gas, Inc. | Incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the SEC on May 15, 2018 |
| 4.1 | Indenture, dated May 15, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee (including Form of 8.50% Senior Secured Second Lien Notes due 2023) | Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on May 18, 2018 |
| 4.2 | First Supplemental Indenture, dated September 18, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee | Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on September 18, 2018 |
| 4.3 | Second Supplemental Indenture, dated October 5, 2018, between Northern Oil and Gas, Inc. and Wilmington Trust, National Association, as trustee | Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the SEC on October 9, 2018 |
| 10.1 | Senior Unsecured Promissory Note, dated July 1, 2019, by and among Northern Oil and Gas, Inc. and VEN Bakken, LLC | Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on July 2, 2019 |
| 10.2 | Separation and Release Agreement, dated July 31, 2019, by and between Northern Oil and Gas, Inc. and Michael L. Reger | Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the SEC on August 2, 2019 |
| 10.3 | Land Acquisition Consulting Agreement, dated July 31, 2019, by and between Northern Oil and Gas, Inc. and Michael L. Reger | Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed with the SEC on August 2, 2019 |
| 31.1 | Certification of the Principal Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 | Filed herewith |
| 31.2 | Certification of the Principal Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 | Filed herewith |
| 32.1 | Certification of the Principal Executive Officer and Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 | Filed herewith |
| 101.INS | XBRL Instance Document | Filed herewith |
| 101.SCH | XBRL Taxonomy Extension Schema Document | Filed herewith |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document | Filed herewith |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document | Filed herewith |
| 101.LAB | XBRL Taxonomy Extension Label Linkbase Document | Filed herewith |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document | Filed herewith |

| | | |
|---|---|---|
| 104 | The cover page from Northern Oil and Gas, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2019, formatted in Inline XBRL | Filed herewith |

**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: | November 12, 2019 | By: | /s/ Brandon Elliott |
| | | | Brandon Elliott, Chief Executive Officer and principal executive officer<br>(on behalf of Registrant) |
| Date: | November 12, 2019 | By: | /s/ Chad Allen |
| | | | Chad Allen, Chief Accounting Officer and principal accounting officer |

**Exhibit 31.1**

**CERTIFICATION**

I, Brandon Elliott certify that:

1. I have reviewed this quarterly report on Form 10-Q of Northern Oil and Gas, Inc.;

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

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

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

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

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

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

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

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

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

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

Dated: November 12, 2019

By: /s/ Brandon Elliott

Brandon Elliott
Principal Executive Officer

**Exhibit 31.2**

**CERTIFICATION**

I, Nicholas O'Grady certify that:

1. I have reviewed this quarterly report on Form 10-Q of Northern Oil and Gas, Inc.;

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

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

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

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

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

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

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

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

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

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

Dated: November 12, 2019

By: /s/ Nicholas O'Grady
Nicholas O'Grady
Principal Financial Officer

**Exhibit 32.1**

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

In connection with the Quarterly Report of Northern Oil and Gas, Inc., (the “Company”) on Form 10-Q for the quarterly period ended September 30, 2019, as filed with the United States Securities and Exchange Commission on the date hereof, (the “Report”), the undersigned officers of the Company hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of his knowledge:

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

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

Dated: November 12, 2019

By: /s/ Brandon Elliott
Brandon Elliott
Principal Executive Officer

Dated: November 12, 2019

By: /s/ Nicholas O'Grady
Nicholas O'Grady
Principal Financial Officer

A signed original of this written statement required by Section 906 of the Sarbanes-Oxley Act of 2002 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.