UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 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, 2018

or

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

For the transition period from _______________ to _______________

Commission file number: 001 31899

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

Delaware (State or other jurisdiction of incorporation or organization)	20 0098515 (I.R.S. Employer Identification No.)
1700 Broadway, Suite 2300 Denver, Colorado (Address of principal executive offices)	80290 2300 (Zip code)

(303) 837 1661
(Registrant's telephone number, including area code)

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	Smaller reporting company
Accelerated filer	Emerging growth company
Non-accelerated filer	

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

Number of shares of the registrant's common stock outstanding at October 19, 2018: 90,994,611 shares.

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GLOSSARY OF CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms “we”, “us”, “our” or “ours” when used in this Quarterly Report on Form 10 Q refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this report:

“ASC” Accounting Standards Codification.

“Bbl” One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil, NGLs and other liquid hydrocarbons.

“Bcf” One billion cubic feet, used in reference to natural gas.

“BOE” One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals six Mcf of natural gas and one Bbl of crude oil equals one Bbl of natural gas liquids.

“Btu” or “British thermal unit” The quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit.

“completion” The process of preparing an oil and gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production.

“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.

“deterministic method” The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

“development well” A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

“differential” The difference between a benchmark price of 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 either oil or gas in sufficient quantities to justify completion as an oil or gas well.

“exploratory well” A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

“FASB” Financial Accounting Standards Board.

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

"GAAP" Generally accepted accounting principles in the United States of America.

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

"ISDA" International Swaps and Derivatives Association, Inc.

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“lease operating expense” or “LOE” The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

“LIBOR” London interbank offered rate.

“MBbl” One thousand barrels of oil, NGLs or other liquid hydrocarbons.

“MBbl/d” One MBbl per day.

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet, used in reference to natural gas.

“MMBbl” One million barrels of oil, NGLs, or other liquid hydrocarbons.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units, used in reference to natural gas.

“MMcf” One million cubic feet, used in reference to natural gas.

“MMcf/d” One MMcf per day.

“net acres” or “net wells” The sum of the fractional working interests owned in gross acres or wells, as the case may be.

“net production” The total production attributable to our fractional working interest owned.

“NGL” Natural gas liquid.

“NYMEX” The New York Mercantile Exchange.

“plug-and-perf technology” A horizontal well completion technique in which hydraulic fractures are performed in multiple stages, with each stage utilizing a bridge plug to divert fracture stimulation fluids through the casing perforations into the formation within that stage.

“plugging and abandonment” Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of most states legally require plugging of abandoned wells.

“prospect” A property on which indications of oil or gas have been identified based on available seismic and geological information.

“proved developed reserves” Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

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

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The area of the reservoir considered as proved includes all of the following:

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

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

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.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12 month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

“reasonable certainty” If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

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

“reservoir” A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“royalty” The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil or natural gas produced and sold, unencumbered by expenses relating to the drilling, completing or operating of the affected well.

“SEC” The United States Securities and Exchange Commission.

“working interest” The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

“workover” Operations on a producing well to restore or increase production.

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PART I – FINANCIAL INFORMATION

Item 1. Condensed Consolidated Financial Statements

WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (unaudited)

(in thousands, except share and per share data)

	September 30, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 14,187	$ 879,379
Accounts receivable trade, net	315,929	284,214
Prepaid expenses and other	22,617	26,035
Total current assets	352,733	1,189,628
Property and equipment:		
Oil and gas properties, successful efforts method	11,994,921	11,293,650
Other property and equipment	134,663	134,524
Total property and equipment	12,129,584	11,428,174
Less accumulated depreciation, depletion and amortization	(4,809,558)	(4,244,735)
Total property and equipment, net	7,320,026	7,183,439
Other long-term assets	36,580	29,967
TOTAL ASSETS	$ 7,709,339	$ 8,403,034
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ -	$ 958,713
Accounts payable trade	77,495	32,761
Revenues and royalties payable	184,343	171,028
Accrued capital expenditures	74,757	69,744
Accrued interest	35,183	40,971
Accrued liabilities and other	109,399	118,815
Taxes payable	38,494	28,771
Derivative liabilities	106,255	132,525
Total current liabilities	625,926	1,553,328
Long-term debt	2,835,128	2,764,716
Asset retirement obligations	147,941	129,206
Other long-term liabilities	36,491	36,642
Total liabilities	3,645,486	4,483,892
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 225,000,000 shares authorized; 92,130,240 issued and 90,967,365 outstanding as of September 30, 2018 and 92,094,837 issued and 90,698,889 outstanding as of December 31, 2017	92	92
Additional paid-in capital	6,411,669	6,405,490

Accumulated deficit	(2,347,908)	(2,486,440)
Total equity	4,063,853	3,919,142
TOTAL LIABILITIES AND EQUITY	$ 7,709,339	$ 8,403,034

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

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WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
OPERATING REVENUES				
Oil, NGL and natural gas sales	$ 566,695	$ 324,191	$ 1,608,181	$ 1,007,023
OPERATING EXPENSES				
Lease operating expenses	92,461	90,615	274,763	267,277
Production taxes	46,509	27,499	127,653	86,621
Depreciation, depletion and amortization	197,006	212,846	584,219	673,288
Exploration and impairment	11,030	17,657	39,011	63,793
General and administrative	31,901	30,084	94,982	92,644
Derivative loss, net	21,063	30,867	177,210	47,281
Loss on sale of properties	230	398,752	1,716	401,050
Amortization of deferred gain on sale	(2,870)	(3,175)	(8,699)	(9,757)
Total operating expenses	397,330	805,145	1,290,855	1,622,197
INCOME (LOSS) FROM OPERATIONS	169,365	(480,954)	317,326	(615,174)
OTHER INCOME (EXPENSE)				
Interest expense	(48,328)	(47,693)	(149,558)	(143,641)
Loss on extinguishment of debt	-	-	(31,968)	(1,540)
Interest income and other	363	(83)	2,732	970
Total other expense	(47,965)	(47,776)	(178,794)	(144,211)
INCOME (LOSS) BEFORE INCOME TAXES	121,400	(528,730)	138,532	(759,385)
INCOME TAX BENEFIT				
Current	-	(3,161)	-	(6,367)
Deferred	-	(239,137)	-	(313,634)
Total income tax benefit	-	(242,298)	-	(320,001)
NET INCOME (LOSS)	121,400	(286,432)	138,532	(439,384)
Net loss attributable to noncontrolling interests	-	-	-	14
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 121,400	$ (286,432)	$ 138,532	$ (439,370)
INCOME (LOSS) PER COMMON SHARE (1)				
Basic	$ 1.33	$ (3.16)	$ 1.52	$ (4.85)
Diluted	$ 1.32	$ (3.16)	$ 1.51	$ (4.85)
WEIGHTED AVERAGE SHARES OUTSTANDING (1)				
Basic	90,967	90,698	90,934	90,678
Diluted	91,823	90,698	91,862	90,678

(1)

All share and per share amounts have been retroactively adjusted for the 2017 periods to reflect the Company's one-for-four reverse stock split in November 2017, as described in Note 8 to these condensed consolidated financial statements.

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

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WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(in thousands)

	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 138,532	$ (439,384)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	584,219	673,288
Deferred income tax benefit	-	(313,634)
Amortization of debt issuance costs, debt discount and debt premium	22,976	22,927
Stock-based compensation	10,243	19,051
Amortization of deferred gain on sale	(8,699)	(9,757)
Loss on sale of properties	1,716	401,050
Oil and gas property impairments	25,612	44,270
Loss on extinguishment of debt	31,968	1,540
Non-cash derivative loss	36,585	57,937
Payment for settlement of commodity derivative contract	(61,036)	-
Other, net	(102)	(7,008)
Changes in current assets and liabilities:		
Accounts receivable trade, net	(32,919)	(51,319)
Prepaid expenses and other	3,418	(6,441)
Accounts payable trade and accrued liabilities	31,990	(68,881)
Revenues and royalties payable	12,810	(16,782)
Taxes payable	9,723	(16,451)
Net cash provided by operating activities	807,036	290,406
CASH FLOWS FROM INVESTING ACTIVITIES		
Drilling and development capital expenditures	(579,746)	(616,753)
Acquisition of oil and gas properties	(140,427)	(18,452)
Other property and equipment	(543)	(3,371)
Proceeds from sale of oil and gas properties	3,284	916,176
Net cash provided by (used in) investing activities	(717,432)	277,600
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings under credit agreement	1,672,265	1,630,000
Repayments of borrowings under credit agreement	(1,622,265)	(1,980,000)
Redemption of 6.5% Senior Subordinated Notes due 2018	-	(275,121)
Redemption of 5.0% Senior Notes due 2019	(990,023)	-
Debt issuance costs	(10,709)	-
Restricted stock used for tax withholdings	(4,064)	(4,938)
Net cash used in financing activities	$ (954,796)	$ (630,059)

(Continued)

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WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2018	2017
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	$ (865,192)	$ (62,053)
CASH, CASH EQUIVALENTS AND RESTRICTED CASH		
Beginning of period	879,379	73,225
End of period	$ 14,187	$ 11,172
NONCASH INVESTING ACTIVITIES		
Accrued capital expenditures and accounts payable related to property additions	$ 88,880	$ 147,084

The accompanying notes are an integral part of these condensed consolidated financial statements. (Concluded)

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WHITING PETROLEUM CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY (unaudited)

(in thousands)

	Common Stock		Additional Paid-in	Accumulated	Total Whiting Shareholders'	Noncontrolling	Total
	Shares (1)	Amount	Capital	Deficit	Equity	Interest	Equity
BALANCES - January 1, 2017	91,793	$ 367	$ 6,389,435	$ (1,248,572)	$ 5,141,230	$ 7,962	$ 5,149,192
Net loss	-	-	-	(439,370)	(439,370)	(14)	(439,384)
Conveyance of third party ownership interest in Sustainable Water Resources, LLC	-	-	-	-	-	(7,948)	(7,948)
Restricted stock issued	568	2	(2)	-	-	-	-
Restricted stock forfeited	(255)	(1)	1	-	-	-	-
Restricted stock used for tax withholdings	(101)	-	(4,938)	-	(4,938)	-	(4,938)
Stock-based compensation	-	-	19,051	-	19,051	-	19,051
Cumulative effect of change in accounting principle	-	-	220	(220)	-	-	-
BALANCES - September 30, 2017	92,005	$ 368	$ 6,403,767	$ (1,688,162)	$ 4,715,973	$ -	$ 4,715,973
BALANCES - January 1, 2018	92,095	$ 92	$ 6,405,490	$ (2,486,440)	$ 3,919,142	$ -	$ 3,919,142
Net income	-	-	-	138,532	138,532	-	138,532
Restricted stock issued	451	-	-	-	-	-	-
Restricted stock forfeited	(291)	-	-	-	-	-	-

Restricted stock used for tax withholdings	(125)	-	(4,064)	-	(4,064)	-	(4,064)
Stock-based compensation	-	-	10,243	-	10,243	-	10,243
BALANCES - September 30, 2018	92,130	$ 92	$ 6,411,669	$ (2,347,908)	$ 4,063,853	$ -	$ 4,063,853

(1) All common share amounts have been retroactively adjusted for the 2017 period to reflect the Company's one-for-four reverse stock split in November 2017, as described in Note 8 to these condensed consolidated financial statements.

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

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WHITING PETROLEUM CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. BASIS OF PRESENTATION

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company engaged in the development, production, acquisition and exploration of crude oil, NGLs and natural gas primarily in the Rocky Mountains region of the United States. Unless otherwise specified or the context otherwise requires, all references in these notes to “Whiting” or the “Company” are to Whiting Petroleum Corporation and its consolidated subsidiaries, Whiting Oil and Gas Corporation (“Whiting Oil and Gas”), Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources Corporation and Whiting Programs, Inc.

Condensed Consolidated Financial Statements—The unaudited condensed consolidated financial statements include the accounts of Whiting Petroleum Corporation and its consolidated subsidiaries. Investments in entities which give Whiting significant influence, but not control, over the investee are accounted for using the equity method. Under the equity method, investments are stated at cost plus the Company’s equity in undistributed earnings and losses. All intercompany balances and transactions have been eliminated upon consolidation. These financial statements have been prepared in accordance with GAAP and the SEC rules and regulations for interim financial reporting. In the opinion of management, the accompanying financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company’s interim results. However, operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year. The condensed consolidated financial statements and related notes included in this Quarterly Report on Form 10 Q should be read in conjunction with Whiting’s consolidated financial statements and related notes included in the Company’s Annual Report on Form 10 K for the period ended December 31, 2017. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to consolidated financial statements included in the Company’s 2017 Annual Report on Form 10 K.

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

Adopted and Recently Issued Accounting Pronouncements—In May 2014, the FASB issued Accounting Standards Update No. 2014 09, Revenue from Contracts with Customers (“ASU 2014 09”). The FASB subsequently issued various ASUs which provided additional implementation guidance, and these ASUs collectively make up FASB ASC Topic 606 – Revenue from Contracts with Customers (“ASC 606”). The objective of ASC 606 is to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and International Financial Reporting Standards. ASC 606 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The standard permits retrospective application using either of the following methodologies: (i) restatement of each prior reporting period presented or (ii) recognition of a cumulative-effect adjustment as of the date of initial application. The Company adopted ASC 606 effective January 1, 2018 using the modified retrospective approach. The adoption did not have an impact on the Company’s net income or cash flows, and the Company did not record a cumulative-effect adjustment to retained earnings as a result. However, the adoption did result in changes to the classification of certain fees incurred under pipeline gathering and transportation agreements and gas processing agreements, as well as certain costs attributable to non-operated properties, which led to an overall decrease in total revenues with a corresponding decrease in lease operating expenses under the new standard. Refer to the "Revenue Recognition" footnote for further information on the Company's implementation of this standard.

In February 2016, the 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. The FASB subsequently issued various ASUs which provided additional implementation guidance. ASU 2016 02 and its amendments are 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. The Company plans to recognize a cumulative-effect adjustment as of the beginning of the period of adoption. Early adoption is permitted. The Company is in the process of implementing a lease accounting software and is currently evaluating the effect of adopting ASU 2016 02 on its financial statements, accounting policies, and internal controls. The adoption is primarily expected to result in an increase in the assets and liabilities recorded on its consolidated balance sheet and additional disclosures. The Company does not expect a material impact to its consolidated statement of operations. As of September 30, 2018, the Company had approximately $115 million of contractual obligations related to its non-cancelable leases, drilling rig contracts and pipeline transportation agreements, and it will evaluate those contracts as well as other existing arrangements to determine if they qualify for lease accounting under this standard.

In March 2018, the FASB issued Accounting Standards Update No. 2018 05, Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118 (“ASU 2018 05”). The objective of this ASU is to codify the guidance provided by Staff Accounting Bulletin No. 118 regarding the accounting for the income tax effects of the Tax Cuts and Jobs Act (the “TCJA”) passed by Congress in December 2017 if such accounting is not complete by the time a company issues its financial statements that include the reporting period in which the TCJA was enacted. ASU 2018 05 was effective upon addition to the FASB Codification in March 2018.

2. OIL AND GAS PROPERTIES

Net capitalized costs related to the Company’s oil and gas producing activities at September 30, 2018 and December 31, 2017 are as follows (in thousands):

	September 30, 2018	December 31, 2017
Proved leasehold costs	$ 2,739,348	$ 2,622,576
Unproved leasehold costs	144,143	137,694
Costs of completed wells and facilities	8,864,185	8,288,591
Wells and facilities in progress	247,245	244,789
Total oil and gas properties, successful efforts method	11,994,921	11,293,650
Accumulated depletion	(4,745,391)	(4,185,301)
Oil and gas properties, net	$ 7,249,530	$ 7,108,349

3. ACQUISITIONS AND DIVESTITURES

2018 Acquisitions and Divestitures

On July 31, 2018, the Company completed the acquisition of certain oil and gas properties located in Richland County, Montana and McKenzie County, North Dakota for an aggregate purchase price of $130 million (before closing adjustments). The properties consist of approximately 54,800 net acres in the Williston Basin, including interests in 117 producing oil and gas wells and undeveloped acreage. The revenue and earnings from these properties since the acquisition date are included in our condensed consolidated financial statements for the three and nine months ended September 30, 2018 and are not material. Pro forma revenue and earnings for the acquired properties are not material to our condensed consolidated financial statements and have not been presented accordingly.

The acquisition was recorded using the acquisition method of accounting. The following table summarizes the preliminary allocation of the $127 million adjusted purchase price (which is still subject to post-closing adjustments) to the tangible assets acquired and liabilities assumed in this acquisition based on their relative fair values at the acquisition date, which did not result in the recognition of goodwill or a bargain purchase gain. As the purchase price is further adjusted for post-close adjustments and as oil and gas property valuations are completed, the final purchase price allocation may result in a different allocation to the tangible assets from that which is presented in the table below (in thousands):

Cash consideration	$ 126,938
Fair value of assets and liabilities acquired:	
Proved oil and gas properties	$ 107,701
Unproved oil and gas properties	21,769
Total fair value of oil and gas properties acquired	129,470
Asset retirement obligations	2,532
Total fair value of net assets acquired	$ 126,938

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There were no significant divestitures during the nine months ended September 30, 2018.

2017 Acquisitions and Divestitures

On September 1, 2017, the Company completed the sale of its interests in certain producing oil and gas properties located in the Fort Berthold Indian Reservation area in Dunn and McLean counties of North Dakota, as well as other related assets and liabilities, for aggregate sales proceeds of $500 million (before closing adjustments). The sale was effective September 1, 2017 and resulted in a pre-tax loss on sale of $402 million. The Company used the net proceeds from the sale to repay a portion of the debt outstanding under its credit agreement.

On January 1, 2017, the Company completed the sale of its 50% interest in the Robinson Lake gas processing plant located in Mountrail County, North Dakota and its 50% interest in the Belfield gas processing plant located in Stark County, North Dakota, as well as the associated natural gas, crude oil and water gathering systems, effective January 1, 2017, for aggregate sales proceeds of $375 million (before closing adjustments). The Company used the net proceeds from this transaction to repay a portion of the debt outstanding under its credit agreement.

There were no significant acquisitions during the year ended December 31, 2017.

4. LONG-TERM DEBT

Long-term debt, including the current portion, consisted of the following at September 30, 2018 and December 31, 2017 (in thousands):

	September 30, 2018	December 31, 2017
Credit agreement	$ 50,000	$ -
5.0% Senior Notes due 2019	-	961,409
1.25% Convertible Senior Notes due 2020	562,075	562,075
5.75% Senior Notes due 2021	873,609	873,609
6.25% Senior Notes due 2023	408,296	408,296
6.625% Senior Notes due 2026	1,000,000	1,000,000
Total principal	2,893,980	3,805,389
Unamortized debt discounts and premiums	(34,598)	(50,945)
Unamortized debt issuance costs on notes	(24,254)	(31,015)
Total debt	2,835,128	3,723,429
Less current portion of long-term debt	-	(958,713)
Total long-term debt	$ 2,835,128	$ 2,764,716

Credit Agreement

Whiting Oil and Gas, the Company’s wholly owned subsidiary, has a credit agreement with a syndicate of banks that as of September 30, 2018 had a borrowing base of $2.4 billion and aggregate commitments of $1.75 billion. As of September 30, 2018, the Company had $1.7 billion of available borrowing capacity under the credit agreement, which was net of $50 million of borrowings outstanding and $2 million in letters of credit outstanding.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the Company's proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Upon a redetermination of the borrowing base, either on a periodic or special redetermination date, if borrowings in excess of the revised borrowing capacity were outstanding, the Company could be forced to immediately repay a portion of its debt outstanding under the credit agreement.

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A portion of the revolving credit facility in an aggregate amount not to exceed $50 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of September 30, 2018, $48 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until maturity, when the credit agreement expires and all outstanding borrowings are due. Interest under the credit agreement accrues at the Company's option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR rate plus 1.0% per annum, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. Additionally, the Company also incurs commitment fees as set forth in the table below on the unused portion of the aggregate commitments of the lenders under the credit agreement, which are included as a component of interest expense. At September 30, 2018, the weighted average interest rate on the outstanding principal balance under the credit agreement was 3.7%.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. Except for limited exceptions, the credit agreement also restricts the Company's ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the Company's restricted subsidiaries (as defined in the credit agreement). As of September 30, 2018, there were no retained earnings free from restrictions. The credit agreement requires the Company, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) a total debt to last four quarters' EBITDAX ratio of not greater than 4.0 to 1.0. The Company was in compliance with its covenants under the credit agreement as of September 30, 2018.

The obligations of Whiting Oil and Gas under the credit agreement are collateralized by a first lien on substantially all of Whiting Oil and Gas' and Whiting Resource Corporation's properties. The Company has guaranteed the obligations of Whiting Oil and Gas under the credit agreement and has pledged the stock of its subsidiaries as security for its guarantee.

Senior Notes, Convertible Senior Notes and Senior Subordinated Notes

The following table summarizes the material terms of the Company's senior notes and convertible senior notes outstanding at September 30, 2018:

	2020 Convertible Senior Notes	2021 Senior Notes	2023 Senior Notes	2026 Senior Notes
Outstanding principal (in thousands)	$ 562,075	$ 873,609	$ 408,296	$ 1,000,000
Interest rate	1.25%	5.75%	6.25%	6.625%
Maturity date	Apr 1, 2020	Mar 15, 2021	Apr 1, 2023	Jan 15, 2026
Interest payment dates	Apr 1, Oct 1	Mar 15, Sep 15	Apr 1, Oct 1	Jan 15, Jul 15
Make-whole redemption date (1)	N/A (2)	Dec 15, 2020	Jan 1, 2023	Oct 15, 2025

(1) On or after these dates, the Company may redeem the applicable series of notes, in whole or in part, at a redemption price equal to 100% of the principal amount redeemed, together with accrued and unpaid interest up to the redemption date. At any time prior to these dates, the Company may redeem the notes at a redemption price that includes an applicable premium as defined in the indentures to such notes.
(2) The indenture governing our 1.25% Convertible Senior Notes due 2020 does not allow for optional redemption by the Company prior to the maturity date.

Senior Notes and Senior Subordinated Notes—In September 2010, the Company issued at par $350 million of 6.5% Senior Subordinated Notes due October 2018 (the “2018 Senior Subordinated Notes”).

In September 2013, the Company issued at par $1.1 billion of 5.0% Senior Notes due March 2019 (the “2019 Senior Notes”) and $800 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400 million of 5.75% Senior Notes due March 2021 (collectively, the “2021 Senior Notes”). The debt premium recorded in connection with the issuance of the 2021 Senior Notes is being amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 5.5% per annum.

In March 2015, the Company issued at par $750 million of 6.25% Senior Notes due April 2023 (the “2023 Senior Notes”).

In December 2017, the Company issued at par $1.0 billion of 6.625% Senior Notes due January 2026 (the “2026 Senior Notes” and together with the 2021 Senior Notes and the 2023 Senior Notes, the “Senior Notes”). The Company used the net proceeds from this offering to redeem on January 26, 2018 all of the then outstanding 2019 Senior Notes. Refer to “Redemption of 2019 Senior Notes” below for more information on the redemption of the 2019 Senior Notes.

Exchange of Senior Notes and Senior Subordinated Notes for Convertible Notes. During 2016, the Company exchanged (i) $75 million aggregate principal amount of its 2018 Senior Subordinated Notes, (ii) $139 million aggregate principal amount of its 2019 Senior Notes, (iii) $326 million aggregate principal amount of its 2021 Senior Notes, and (iv) $342 million aggregate principal amount of its 2023 Senior Notes, for the same aggregate principal amount of convertible notes. Subsequently during 2016, all $882 million aggregate principal amount of these convertible notes was converted into approximately 21.6 million shares of the Company’s common stock pursuant to the terms of the notes.

Redemption of 2018 Senior Subordinated Notes. On February 2, 2017, the Company paid $281 million to redeem all of the then outstanding $275 million aggregate principal amount of 2018 Senior Subordinated Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the notes. The Company financed the redemption with borrowings under its credit agreement. As a result of the redemption, Whiting recognized a $2 million loss on extinguishment of debt, which consisted of a non-cash charge for the acceleration of unamortized debt issuance costs on the notes. As of March 31, 2017, no 2018 Senior Subordinated Notes remained outstanding.

Redemption of 2019 Senior Notes. On January 26, 2018, the Company paid $1.0 billion to redeem all of the remaining $961 million aggregate principal amount of the 2019 Senior Notes, which payment consisted of the 102.976% redemption price plus all accrued and unpaid interest on the notes. The Company financed the redemption with proceeds from the issuance of the 2026 Senior Notes and borrowings under its credit agreement. As a result of the redemption, the Company recognized a $31 million loss on extinguishment of debt, which included the redemption premium and a non-cash charge for the acceleration of unamortized debt issuance costs on the notes. As of March 31, 2018, no 2019 Senior Notes remained outstanding.

2020 Convertible Senior Notes—In March 2015, the Company issued at par $1,250 million of 1.25% Convertible Senior Notes due April 2020 (the “2020 Convertible Senior Notes”) for net proceeds of $1.2 billion, net of initial purchasers’ fees of $25 million. During 2016, the Company exchanged $688 million aggregate principal amount of its 2020

Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Subsequently during 2016, all $688 million aggregate principal amount of these mandatory convertible notes was converted into approximately 17.8 million shares of the Company's common stock pursuant to the terms of the notes.

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For the remaining $562 million aggregate principal amount of 2020 Convertible Senior Notes outstanding as of September 30, 2018, the Company has the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at its election. The Company's intent is to settle the principal amount of the 2020 Convertible Senior Notes in cash upon conversion. Prior to January 1, 2020, the 2020 Convertible Senior Notes will be convertible at the holder's option only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on June 30, 2015 (and only during such calendar quarter), if the last reported sale price of the Company's common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading price per $1,000 principal amount of the 2020 Convertible Senior Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of the Company's common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events. On or after January 1, 2020, the 2020 Convertible Senior Notes will be convertible at any time until the second scheduled trading day immediately preceding the April 1, 2020 maturity date of the notes. The notes will be convertible at a current conversion rate of 6.4102 shares of Whiting's common stock per $1,000 principal amount of the notes, which is equivalent to a current conversion price of approximately $156.00. The conversion rate will be subject to adjustment in some events. In addition, following certain corporate events that occur prior to the maturity date, the Company will increase, in certain circumstances, the conversion rate for a holder who elects to convert its 2020 Convertible Senior Notes in connection with such corporate event. As of September 30, 2018, none of the contingent conditions allowing holders of the 2020 Convertible Senior Notes to convert these notes had been met.

Upon issuance, the Company separately accounted for the liability and equity components of the 2020 Convertible Senior Notes. The liability component was recorded at the estimated fair value of a similar debt instrument without the conversion feature. The difference between the principal amount of the 2020 Convertible Senior Notes and the estimated fair value of the liability component was recorded as a debt discount and is being amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 5.6% per annum. The fair value of the liability component of the 2020 Convertible Senior Notes as of the issuance date was estimated at $1.0 billion, resulting in a debt discount at inception of $238 million. The equity component, representing the value of the conversion option, was computed by deducting the fair value of the liability component from the initial proceeds of the 2020 Convertible Senior Notes issuance. This equity component was recorded, net of deferred taxes and issuance costs, in additional paid-in capital within shareholders' equity, and will not be remeasured as long as it continues to meet the conditions for equity classification.

Transaction costs related to the 2020 Convertible Senior Notes issuance were allocated to the liability and equity components based on their relative fair values. Issuance costs attributable to the liability component were recorded as a reduction to the carrying value of long-term debt on the consolidated balance sheet and are being amortized to interest expense over the term of the notes using the effective interest method. Issuance costs attributable to the equity component were recorded as a charge to additional paid-in capital within shareholders' equity.

The 2020 Convertible Senior Notes consisted of the following at September 30, 2018 and December 31, 2017 (in thousands):

	September 30, 2018	December 31, 2017
Liability component		

Principal	$ 562,075	$ 562,075
Less: unamortized note discount	(35,161)	(51,666)
Less: unamortized debt issuance costs	(2,802)	(4,178)
Net carrying value	$ 524,112	$ 506,231
Equity component (1)	$ 136,522	$ 136,522

(1) Recorded in additional paid-in capital, net of $5 million of issuance costs and $50 million of deferred taxes.

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The following table presents the interest expense recognized on the 2020 Convertible Senior Notes related to the stated interest rate and amortization of the debt discount for the three and nine months ended September 30, 2018 and 2017 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Interest expense on 2020 Convertible Senior Notes	$ 7,335	$ 7,032	$ 21,774	$ 20,876

Security and Guarantees

The Senior Notes and the 2020 Convertible Senior Notes are unsecured obligations of Whiting Petroleum Corporation and these unsecured obligations are subordinated to all of the Company’s secured indebtedness, which consists of Whiting Oil and Gas’ credit agreement.

The Company’s obligations under the Senior Notes and the 2020 Convertible Senior Notes are guaranteed by the Company’s 100% owned subsidiaries, Whiting Oil and Gas, Whiting US Holding Company, Whiting Canadian Holding Company ULC and Whiting Resources Corporation (the “Guarantors”). These guarantees are full and unconditional and joint and several among the Guarantors. Any subsidiaries other than these Guarantors are minor subsidiaries as defined by Rule 3 10(h)(6) of Regulation S X of the SEC. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in its consolidated subsidiaries.

5. ASSET RETIREMENT OBLIGATIONS

The Company’s asset retirement obligations represent the present value of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California) in accordance with applicable local, state and federal laws. The current portions at September 30, 2018 and December 31, 2017 were $3 million and $5 million, respectively, and have been included in accrued liabilities and other in the consolidated balance sheets. The following table provides a reconciliation of the Company’s asset retirement obligations for the nine months ended September 30, 2018 (in thousands):

Asset retirement obligation at January 1, 2018	$ 134,237
Additional liability incurred	11,406
Revisions to estimated cash flows	1,239
Accretion expense	8,365
Obligations on sold properties	(640)
Liabilities settled	(3,200)
Asset retirement obligation at September 30, 2018	$ 151,407

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and it uses derivative instruments to manage its commodity price risk. In addition, the Company periodically enters into contracts that contain embedded features which are required to be bifurcated and accounted for separately as derivatives.

Commodity Derivative Contracts—Historically, prices received for crude oil and natural gas production have been volatile because of supply and demand factors, worldwide political factors, general economic conditions and seasonal weather patterns. Whiting primarily enters into derivative contracts such as crude oil costless collars and swaps, as well as sales and delivery contracts, to achieve a more predictable cash flow by reducing its exposure to commodity price volatility, thereby ensuring adequate funding for the Company's capital programs and facilitating the management of returns on drilling programs and acquisitions. The Company does not enter into derivative contracts for speculative or trading purposes.

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Crude Oil Costless Collars and Swaps. Costless collars are designed to establish floor and ceiling prices on anticipated future oil or gas production, while swaps establish a fixed price for anticipated future oil or gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements.

The table below details the Company's costless collar and swap derivatives entered into to hedge forecasted crude oil production revenues as of October 1, 2018.

Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price for Crude Oil (per Bbl)
Three-way collars (1)	Oct - Dec 2018	4,350,000	\$37.07 - \$47.07 - \$57.30
Swaps	Oct - Dec 2018	1,200,000	\$61.74
Collars	Jan - Dec 2019	9,900,000	\$51.21 - \$77.14
	Total	15,450,000	

(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) Whiting will receive for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

Crude Oil Sales and Delivery Contract. As of December 31, 2017, the Company had a long-term crude oil sales and delivery contract for oil volumes produced from its Redtail field in Colorado. Under the terms of the agreement, Whiting had committed to deliver certain fixed volumes of crude oil through April 2020. The Company determined it was not probable that future oil production from its Redtail field would be sufficient to meet the minimum volume requirements specified in this contract; accordingly, the Company would not settle this contract through physical delivery of crude oil volumes. As a result, Whiting determined that this contract would not qualify for the "normal purchase normal sale" exclusion and has therefore reflected the contract at fair value in the consolidated financial statements. As of December 31, 2017, the estimated fair value of this derivative contract was a liability of \$63 million. On February 1, 2018, Whiting paid \$61 million to the counterparty to settle all future minimum volume commitments under this agreement. Accordingly, this crude oil sales and delivery contract was fully terminated, and the fair value of the corresponding derivative was therefore zero as of that date.

Embedded Derivatives—In July 2016, the Company entered into a purchase and sale agreement with the buyer of its North Ward Estes Properties, whereby the buyer agreed to pay Whiting additional proceeds of \$100,000 for every \$0.01 that, as of June 28, 2018, the average NYMEX crude oil futures contract price for each month from August 2018 through July 2021 is above \$50.00/Bbl up to a maximum amount of \$100 million. The Company determined that this NYMEX-linked contingent payment was not clearly and closely related to the host contract, and the Company therefore bifurcated this embedded feature and reflected it at its estimated fair value in the consolidated financial statements. On July 19, 2017, the buyer paid \$35 million to Whiting to settle this NYMEX-linked contingent payment, and accordingly, the embedded derivative's fair value was zero as of December 31, 2017 and September 30, 2018.

Derivative Instrument Reporting—All derivative instruments are recorded in the consolidated financial statements at fair value, other than derivative instruments that meet the "normal purchase normal sale" exclusion or other derivative scope exceptions. The following tables summarize the effects of derivative instruments on the consolidated statements of operations for the three and nine months ended September 30, 2018 and 2017 (in thousands):

Not Designated as ASC 815 Hedges	Statement of Operations Classification	Loss Recognized in Income Three Months Ended September 30, 2018	2017
Commodity contracts	Derivative loss, net	$ 21,063	$ 30,867
Total		$ 21,063	$ 30,867

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Not Designated as ASC 815 Hedges	Statement of Operations Classification	Loss Recognized in Income Nine Months Ended September 30, 2018	2017
Commodity contracts	Derivative loss, net	$ 177,210	$ 28,572
Embedded derivatives	Derivative loss, net	-	18,709
Total		$ 177,210	$ 47,281

Offsetting of Derivative Assets and Liabilities. The Company nets its financial derivative instrument fair value amounts executed with the same counterparty pursuant to ISDA master agreements, which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The following tables summarize the location and fair value amounts of all the Company's derivative instruments in the consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the consolidated balance sheets (in thousands):

		September 30, 2018 (1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets				
Commodity contracts - current	Prepaid expenses and other	$ 3,834	$ (3,834)	$ -
Commodity contracts - non-current	Other long-term assets	2,406	(2,320)	86
Total derivative assets		$ 6,240	$ (6,154)	$ 86
Derivative liabilities				
Commodity contracts - current	Derivative liabilities	$ 110,089	$ (3,834)	$ 106,255
Commodity contracts - non-current	Other long-term liabilities	4,226	(2,320)	1,906
Total derivative liabilities		$ 114,315	$ (6,154)	$ 108,161

		December 31, 2017 (1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets				
Commodity contracts - current	Prepaid expenses and other	$ 9,829	$ (9,829)	$ -
Total derivative assets		$ 9,829	$ (9,829)	$ -
Derivative liabilities				
Commodity contracts - current	Derivative liabilities	$ 142,354	$ (9,829)	$ 132,525

Total derivative liabilities	$ 142,354	$ (9,829)	$ 132,525

(1) Because counterparties to the Company's financial derivative contracts subject to master netting arrangements are lenders under Whiting Oil and Gas' credit agreement, which eliminates its need to post or receive collateral associated with its derivative positions, columns for cash collateral pledged or received have not been presented in these tables.

Contingent Features in Financial Derivative Instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's financial derivative contracts are high credit-quality financial institutions that are lenders under Whiting's credit agreement. The Company uses only credit agreement participants to hedge with, since these institutions are secured equally with the holders of Whiting's bank debt, which eliminates the potential need to post collateral when Whiting is in a derivative liability position. As a result, the Company is not required to post letters of credit or corporate guarantees for its derivative counterparties in order to secure contract performance obligations.

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7. FAIR VALUE MEASUREMENTS

The Company follows FASB ASC Topic 820, Fair Value Measurement and Disclosure, which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company reflects transfers between the three levels at the beginning of the reporting period in which the availability of observable inputs no longer justifies classification in the original level.

Cash, cash equivalents, accounts receivable and accounts payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The Company's credit agreement has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates and the applicable margins represent market rates.

The Company's senior notes are recorded at cost and the Company's convertible senior notes are recorded at fair value at the date of issuance. The following table summarizes the fair values and carrying values of these instruments as of September 30, 2018 and December 31, 2017 (in thousands):

	September 30, 2018		December 31, 2017	
	Fair Value (1)	Carrying Value (2)	Fair Value (1)	Carrying Value (2)
5.0% Senior Notes due 2019	$ -	$ -	$ 985,444	$ 958,713
1.25% Convertible Senior Notes due 2020	540,716	524,112	517,109	506,231
5.75% Senior Notes due 2021	895,336	870,222	897,633	869,284
6.25% Senior Notes due 2023	422,586	404,475	418,503	403,940
6.625% Senior Notes due 2026	1,043,750	986,319	1,025,000	985,261
Total	$ 2,902,388	$ 2,785,128	$ 3,843,689	$ 3,723,429

(1) Fair values are based on quoted market prices for these debt securities, and such fair values are therefore designated as Level 1 within the valuation hierarchy.

(2) Carrying values are presented net of unamortized debt issuance costs and debt discounts or premiums.

The Company's derivative financial instruments are recorded at fair value and include a measure of the Company's own nonperformance risk or that of its counterparty, as appropriate. The following tables present information about the Company's financial liabilities

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measured at fair value on a recurring basis as of September 30, 2018 and December 31, 2017, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value September 30, 2018
Financial Assets				
Commodity derivatives – non-current	$ -	$ 86	$ -	$ 86
Total financial assets	$ -	$ 86	$ -	$ 86
Financial Liabilities				
Commodity derivatives – current	$ -	$ 106,255	$ -	$ 106,255
Commodity derivatives – non-current	-	1,906	-	1,906
Total financial liabilities	$ -	$ 108,161	$ -	$ 108,161

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2017
Financial Liabilities				
Commodity derivatives – current	$ -	$ 69,247	$ 63,278	$ 132,525
Total financial liabilities	$ -	$ 69,247	$ 63,278	$ 132,525

The following methods and assumptions were used to estimate the fair values of the Company's financial assets and liabilities that are measured on a recurring basis:

Commodity Derivatives. Commodity derivative instruments consist mainly of costless collars and swaps for crude oil. The Company's costless collars and swaps are valued based on an income approach. Both the option and swap models consider various assumptions, such as quoted forward prices for commodities, time value and volatility factors. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy. The discount rates used in the fair values of these instruments include a measure of either the Company's or the counterparty's nonperformance risk, as appropriate. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

In addition, the Company had a long-term crude oil sales and delivery contract, whereby it had committed to deliver certain fixed volumes of crude oil through April 2020. Whiting determined that the contract did not meet the "normal purchase normal sale" exclusion, and therefore reflected this contract at fair value in its consolidated financial statements prior to settlement. This commodity derivative was valued based on a probability-weighted income approach which considered various assumptions, including quoted spot prices for commodities, market differentials for crude oil, U.S. Treasury rates and either the Company's or the counterparty's nonperformance risk, as appropriate. The assumptions used in the valuation of the crude oil sales and delivery contract included certain market differential metrics that were unobservable during the term of the contract. Such unobservable inputs were significant to the contract valuation methodology, and the contract's fair value was therefore designated as Level 3 within the valuation hierarchy. On February 1, 2018, Whiting paid $61 million to the counterparty to settle all future minimum volume commitments under this agreement. Accordingly, this derivative was settled in its entirety as of that date.

Embedded Derivatives. The Company had an embedded derivative related to its purchase and sale agreement with the buyer of the North Ward Estes Properties. The agreement included a contingent payment linked to NYMEX crude oil prices which the Company determined was not clearly and closely related to the host contract, and the Company therefore bifurcated this embedded feature and reflected it at fair value in the consolidated financial statements prior to settlement. The fair value of this embedded derivative was determined using a modified Black-Scholes swaption pricing model which considers various assumptions, including quoted forward prices for commodities, time value and volatility factors. These assumptions were observable in the marketplace throughout the full term of the financial instrument, could be derived from observable data or were supported by observable levels at which transactions are executed in the marketplace, and were therefore designated as Level 2 within the valuation hierarchy. The discount rate used in the fair value of this instrument included a measure of the counterparty's nonperformance risk. On July 19, 2017, the buyer paid $35 million to Whiting in satisfaction of this contingent payment. Accordingly, the embedded derivative was settled in its entirety as of that date.

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Level 3 Fair Value Measurements—A third-party valuation specialist was utilized in determining the fair value of the Company's derivative instrument designated as Level 3. The Company reviewed these valuations, including the related model inputs and assumptions, and analyzed changes in fair value measurements between periods. The Company corroborated such inputs, calculations and fair value changes using various methodologies, and reviewed unobservable inputs for reasonableness utilizing relevant information from other published sources.

The following table presents a reconciliation of changes in the fair value of financial liabilities designated as Level 3 in the valuation hierarchy for the three and nine months ended September 30, 2018 and 2017 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Fair value liability, beginning of period	$ -	$ (61,952)	$ (63,278)	$ (9,214)
Unrealized gains (losses) on commodity derivative contracts included in earnings (1)	-	5,178	2,242	(47,560)
Settlement of commodity derivative contracts	-	-	61,036	-
Transfers into (out of) Level 3	-	-	-	-
Fair value liability, end of period	$ -	$ (56,774)	$ -	$ (56,774)

(1) Included in derivative loss, net in the consolidated statements of operations.

Non-recurring Fair Value Measurements—The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company did not recognize any impairment write-downs with respect to its proved property during the reporting periods presented.

8. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

Common Stock—On November 8, 2017 and following approval by the Company's stockholders of an amendment to its certificate of incorporation to effect a reverse stock split, the Company's Board of Directors approved a reverse stock split of Whiting's common stock at a ratio of one-for-four and a reduction in the number of authorized shares of the Company's common stock from 600,000,000 shares to 225,000,000. Whiting's common stock began trading on a split-adjusted basis on November 9, 2017 upon opening of the New York Stock Exchange trading day. All share and per share amounts in these consolidated financial statements and related notes for periods prior to November 2017 have been retroactively adjusted to reflect the reverse stock split.

Noncontrolling Interest—The Company's noncontrolling interest represented an unrelated third party's 25% ownership interest in Sustainable Water Resources, LLC ("SWR"). During the third quarter of 2017, the third party's ownership interest in SWR was assigned back to SWR.

9. REVENUE RECOGNITION

The Company adopted ASC 606 effective January 1, 2018, which replaces previous revenue recognition requirements under FASB ASC Topic 605 – Revenue Recognition ("ASC 605"). The standard was adopted using the modified retrospective approach which requires the Company to recognize in retained earnings at the date of adoption the cumulative effect of the application of ASC 606 to all existing revenue contracts which were not substantially complete as of January 1, 2018. The Company has elected the contract modification practical expedient which allows the Company to reflect the aggregate effect of all modifications prior to the date of adoption when applying ASC 606.

Although the adoption of ASC 606 did not have an impact on the Company’s net income or cash flows, it did result in the reclassification of certain fees incurred under pipeline gathering and transportation agreements and gas processing agreements, as well as certain costs

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attributable to non-operated properties. Such reclassification led to an overall decrease in total revenues with a corresponding decrease in lease operating expenses as follows (in thousands):

	Three Months Ended September 30, 2018			Nine Months Ended September 30, 2018		
	Under ASC 606	Under ASC 605	Difference	Under ASC 606	Under ASC 605	Difference
OPERATING REVENUES						
Oil sales	$ 511,904	$ 507,513	$ 4,391	$ 1,448,310	$ 1,436,984	$ 11,326
NGL and natural gas sales	54,791	70,526	(15,735)	159,871	201,826	(41,955)
Oil, NGL and natural gas sales	$ 566,695	$ 578,039	$ (11,344)	$ 1,608,181	$ 1,638,810	$ (30,629)
OPERATING EXPENSES						
Lease operating expenses	$ 92,461	$ 103,805	$ (11,344)	$ 274,763	$ 305,392	$ (30,629)
Total operating expenses	$ 397,330	$ 408,674	$ (11,344)	$ 1,290,855	$ 1,321,484	$ (30,629)
INCOME FROM OPERATIONS	$ 169,365	$ 169,365	$ -	$ 317,326	$ 317,326	$ -

The reclassification of fees between operating revenues and expenses is the result of the Company's assessment of the point in time at which its performance obligations under its commodity sales contracts are satisfied and control of the commodity is transferred to the customer. The Company has determined that its contracts for the sale of crude oil, unprocessed natural gas, residue gas and NGLs contain monthly performance obligations to deliver product at locations specified in the contract. Control is transferred at the delivery location, at which point the performance obligation has been satisfied and revenue is recognized. Fees included in the contract that are incurred prior to control transfer are classified as lease operating expense and fees incurred after control transfers are included as a reduction to the transaction price. The transaction price at which revenue is recognized consists entirely of variable consideration based on quoted market prices less various fees and the quantity of volumes delivered.

Whiting receives payment for product sales 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 accounts receivable trade, net in the consolidated balance sheets. As of January 1, 2018 and September 30, 2018, such receivable balances were $186 million and $230 million, respectively. 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 has elected to utilize the practical expedient in ASC 606 that states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under our contracts, each monthly delivery of product represents a separate performance obligation, therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

The Company previously utilized the entitlements method to account for product imbalances, which is no longer applicable under ASC 606. The impact to the financial statements resulting from this change in accounting for our production imbalances was not significant.

10. STOCK-BASED COMPENSATION

Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2013 Equity Incentive Plan, as amended and restated (the “2013 Equity Plan”), which replaced the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the “2003 Equity Plan”) and granted the authority to issue 1,325,000 shares of the Company’s common stock. During 2016, the 2013 Equity Plan was amended to include the authority to issue an additional 1,375,000 shares of the Company’s common stock. Upon shareholder approval of the 2013 Equity Plan, the 2003 Equity Plan was terminated. The 2003 Equity Plan continues to govern awards that were outstanding as of the date of its termination, which remain in effect pursuant to their terms. Any shares netted or forfeited under the 2003 Equity Plan and any shares forfeited under the 2013 Equity Plan will be available for future issuance under the 2013 Equity Plan. However, shares netted for tax withholding under the 2013 Equity Plan will be cancelled and will not be available for future issuance. Under the

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2013 Equity Plan, no employee or officer participant may be granted options for more than 225,000 shares of common stock, stock appreciation rights relating to more than 225,000 shares of common stock, more than 150,000 shares of restricted stock (“RSAs”), more than 150,000 restricted stock units (“RSUs”), more than 150,000 performance shares (“PSAs”), or more than 150,000 performance share units (“PSUs”) during any calendar year. In addition, no non-employee director participant may be granted options for more than 25,000 shares of common stock, stock appreciation rights relating to more than 25,000 shares of common stock, more than 25,000 RSAs, or more than 25,000 RSUs during any calendar year. As of September 30, 2018, 969,919 shares of common stock remained available for grant under the 2013 Equity Plan.

The Company grants service-based RSAs and RSUs to executive officers and employees, which generally vest ratably over a three-year service period. The Company also grants service-based RSAs to directors, which generally vest over a one-year service period. In addition, the Company grants PSAs and PSUs to executive officers that are subject to market-based vesting criteria, which generally vest over a three-year service period. The Company accounts for forfeitures of awards granted under these plans as they occur in determining compensation expense. The Company recognizes compensation expense for all awards subject to market-based vesting conditions regardless of whether it becomes probable that these conditions will be achieved or not, and compensation expense is not reversed if vesting does not actually occur.

During the nine months ended September 30, 2018 and 2017, 239,502 and 409,233 shares, respectively, of service-based RSAs and RSUs were granted to employees, executive officers and directors under the 2013 Equity Plan. The Company determines compensation expense for these share-settled awards using their fair value at the grant date, which is based on the closing bid price of the Company’s common stock on such date. The weighted average grant date fair value of service-based RSAs and RSUs was $32.27 per share and $45.52 per share for the nine months ended September 30, 2018 and 2017, respectively.

During the nine months ended September 30, 2018, 308,432 shares of service-based RSUs were granted to employees under the 2013 Equity Plan. These awards will be settled in cash and are recorded as a liability in the consolidated balance sheets. The Company determines compensation expense for cash-settled RSUs using the fair value at the end of each reporting period, which is based on the closing bid price of the Company’s common stock on such date.

During the nine months ended September 30, 2018, 220,451 PSAs and PSUs subject to certain market-based vesting criteria were granted to executive officers under the 2013 Equity Plan. These market-based awards cliff vest on the third anniversary of the grant date, and the number of shares that will vest at the end of that three-year performance period is determined based on the rank of Whiting’s cumulative stockholder return compared to the stockholder return of a peer group of companies on each anniversary of the grant date over the three-year performance period. The number of awards earned could range from zero up to two times the number of shares initially granted. However, awards earned up to the target shares granted (or 100%) will be settled in shares, while awards earned in excess of the target shares granted will be settled in cash. The cash-settled component of such awards is recorded as a liability in the consolidated balance sheets and will be remeasured at fair value using a Monte Carlo valuation model at the end of each reporting period.

During the nine months ended September 30, 2017, 158,363 PSAs subject to certain market-based vesting criteria were granted to executive officers under the 2013 Equity Plan. These market-based awards cliff vest on the third anniversary of the grant date, and the number of shares that will vest at the end of that three-year performance period is determined based on the rank of Whiting’s cumulative stockholder return compared to the stockholder return of a peer group of companies over the same three-year period. The number of shares earned could range from zero up to two times the number of shares initially granted and will be settled entirely in shares.

For awards subject to market conditions, the grant date fair value is estimated using a Monte Carlo valuation model. 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 Whiting's common stock, and the risk-free

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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:

	2018	2017
Number of simulations	2,500,000	2,500,000
Expected volatility	72.80%	82.44%
Risk-free interest rate	2.12%	1.52%
Dividend yield	—	—

The grant date fair value of the market-based awards that will be settled in shares, as determined by the Monte Carlo valuation model, was $27.28 per share and $65.44 per share in 2018 and 2017, respectively.

The following table shows a summary of the Company’s service-based and market-based awards activity for the nine months ended September 30, 2018:

	Number of Awards		Weighted Average
	Service Based RSAs & RSUs	Market-Based PSAs & PSUs	Grant Date Fair Value
Nonvested awards, January 1	898,421	497,527	$ 45.55
Granted	239,502	220,451	29.88
Vested	(418,995)	-	43.69
Forfeited	(104,745)	(185,855)	65.95
Nonvested awards, September 30	614,183	532,123	$ 34.78

There was no significant stock option activity during the nine months ended September 30, 2018 and 2017.

Total stock-based compensation expense was $7 million and $6 million for the three months ended September 30, 2018 and 2017, respectively, and $18 million and $19 million for the nine months ended September 30, 2018 and 2017, respectively.

11. INCOME TAXES

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The provision for income taxes for the three and nine months ended September 30, 2018 and 2017 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% and 35%, respectively, to pre-tax income primarily because (i) for the three and nine months ended September 30, 2018, a full valuation allowance was in effect, which reduced the Company’s net tax expense to zero, and (ii) for the three and nine months ended September 30, 2017, state income taxes and the partial release of a valuation allowance on net operating losses increased the expected tax benefit for the periods, while estimated permanent differences decreased the expected tax benefit.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion, or all, of the Company’s deferred tax assets will not be realized. In making such determination, the Company considers all available positive and negative evidence, including future reversals of temporary differences, tax-planning strategies and projected future taxable income and results of operations. If the Company concludes that it is more likely than not that some portion, or all, of its deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. At December 31, 2017, the Company recorded a full valuation allowance on its net deferred tax assets. The Company assesses the appropriateness of its valuation allowance on a quarterly basis. As of September 30, 2018, there was no change in the Company’s assessment of the realizability of its deferred tax assets, and the full valuation allowance remains in effect.

The computation of the annual estimated effective tax rate at each interim period requires certain estimates and significant judgment including, but not limited to, the expected operating income for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent and temporary differences, and the likelihood of recovering deferred tax assets generated in the

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current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained, additional information becomes known or as the tax environment changes.

On December 22, 2017, Congress passed the Tax Cuts and Jobs Act. The new legislation significantly changed the U.S. corporate tax law by, among other things, lowering the U.S. corporate income tax rate from 35% to 21% beginning in January 2018, implementing a territorial tax system and imposing a repatriation tax on deemed repatriated earnings of foreign subsidiaries.

The SEC issued Staff Accounting Bulletin No. 118 ("SAB 118"), which allows registrants to record provisional amounts during a one year "measurement period" similar to that used to account for business combinations, however, the measurement period is deemed to have ended earlier when the registrant has obtained, prepared and analyzed the information necessary to finalize its accounting. During the measurement period, impacts of the law are expected to be recorded at the time a reasonable estimate for all or a portion of the effects can be made, and provisional amounts can be recognized and adjusted as information becomes available, prepared or analyzed. SAB 118 outlines a three-step process to be applied at each reporting period to account for and qualitatively disclose (i) the effects of the change in tax law for which accounting is complete, (ii) provisional amounts (or adjustments to provisional amounts) for the effects of the change in tax law where accounting is not complete, but where a reasonable estimate has been made, and (iii) areas affected by the change in tax law where a reasonable estimate cannot yet be made and therefore taxes are reflected in accordance with law prior to the enactment of the TCJA.

The TCJA modified executive compensation deduction limitations under IRC Section 162(m). The Company was able to reasonably estimate the impacts of the Section 162(m) changes and recorded an initial provisional reduction to deferred tax assets of $1 million for the year ended December 31, 2017. The accounting for this item is not yet complete as further guidance is needed from tax authorities. The Company expects to complete its accounting within the prescribed measurement period.

The TCJA implemented mandatory repatriation of previously untaxed foreign earnings of specified foreign corporations. The Company has estimated that it has no untaxed foreign-sourced earnings and profits from a specified foreign corporation, and accordingly, no provisional amount was recorded as of September 30, 2018 or December 31, 2017. The Company expects to complete its accounting for this element of the TCJA within the prescribed measurement period.

The Company's accounting for the following elements of the TCJA is incomplete, however the Company expects to complete its accounting within the prescribed measurement period: (i) ability to capitalize and amortize intangible drilling costs under IRC Section 59(e) and (ii) interest deduction limitations under IRC Section 163(j). Reasonable estimates of the impact to the Company's financial statements could not be made, and accordingly, no adjustments were recorded to the financial statements as of September 30, 2018 or December 31, 2017. The Company will assess the impact of these sections of the TCJA on its financial statements as further clarification and guidance is issued by regulatory authorities.

12. EARNINGS PER SHARE

The reconciliations between basic and diluted earnings (loss) per share are as follows (in thousands, except per share data):

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Basic Earnings (Loss) Per Share (1)				
Net income (loss) attributable to common shareholders	$ 121,400	$ (286,432)	$ 138,532	$ (439,370)
Weighted average shares outstanding, basic	90,967	90,698	90,934	90,678
Earnings (loss) per common share, basic	$ 1.33	$ (3.16)	$ 1.52	$ (4.85)
Diluted Earnings (Loss) Per Share (1)				
Net income (loss) attributable to common shareholders	$ 121,400	$ (286,432)	$ 138,532	$ (439,370)
Weighted average shares outstanding, basic	90,967	90,698	90,934	90,678
Service-based awards, market-based awards and stock options	856	-	928	-
Weighted average shares outstanding, diluted	91,823	90,698	91,862	90,678
Earnings (loss) per common share, diluted	$ 1.32	$ (3.16)	$ 1.51	$ (4.85)

(1) All share and per share amounts have been retroactively adjusted for the 2017 periods to reflect the Company’s one-for-four reverse stock split in November 2017, as described in Note 8 to these condensed consolidated financial statements.

During the three months ended September 30, 2018, the diluted earnings per share calculation excludes the effect of 110,604 common shares for stock options that were out-of-the-money as of September 30, 2018.

During the three months ended September 30, 2017, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of 60,687 shares of service-based awards and 878 stock options. In addition, the diluted earnings per share calculation for the three months ended September 30, 2017 excludes the effect of 125,515 common shares for stock options that were out-of-the-money and 340,290 shares of market-based awards that did not meet the market-based vesting criteria as of September 30, 2017.

During the nine months ended September 30, 2018, the diluted earnings per share calculation excludes the effect of 114,582 common shares for stock options that were out-of-the-money.

During the nine months ended September 30, 2017, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of 470,383 shares of service-based awards and 1,108 stock options. In addition, the diluted earnings per share calculation for the nine months ended September 30, 2017 excludes the effect of 125,772 common shares for stock options that were out-of-the-money and 347,019 shares of market-based awards that did not meet the market-based vesting criteria as of September 30, 2017.

Refer to the “Stock-Based Compensation” footnote for further information on the Company’s service-based awards, market-based awards and stock options.

As discussed in the “Long-Term Debt” footnote, the Company has the option to settle conversions of the 2020 Convertible Senior Notes with cash, shares of common stock or any combination thereof. Based on the current conversion price, the entire outstanding principal amount of the 2020 Convertible Senior Notes as of September 30, 2018 would be convertible into approximately 3.6 million shares of the Company’s common stock. However, the Company’s intent is to settle the principal amount of the notes in cash upon conversion. As a result, only the amount by which the conversion value exceeds the aggregate principal amount of the notes (the “conversion spread”) is considered in the diluted earnings per share computation under the treasury stock method. As of September 30, 2018 and 2017, the conversion value did not exceed the principal amount of the notes. Accordingly, there was no impact to diluted earnings per share or the related disclosures for those periods.

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

Unless the context otherwise requires, the terms "Whiting", "we", "us", "our" or "ours" when used in this Item refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), Whiting US Holding Company, Whiting Canadian Holding Company ULC, Whiting Resources Corporation and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in development, production, acquisition and exploration activities primarily in the Rocky Mountains region of the United States. Our current operations and capital programs are focused on organic drilling opportunities and on the development of previously acquired properties, specifically on projects that we believe provide the greatest potential for repeatable success and production growth, while selectively pursuing acquisitions that complement our existing core properties, such as the acquisition discussed below under "Acquisition and Divestiture Highlights". During 2017, we focused our drilling activity on projects that provide the highest rate of return, while closely aligning our capital spending with cash flows generated from operations. During 2018, we continue to focus on high-return projects in our asset portfolio that will add production and reserves while generating free cash flows from operations. In addition, we continually evaluate our property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own, such as the asset sales discussed in the "Acquisitions and Divestitures" footnote in the notes to condensed consolidated financial statements.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such as oil and gas prices, economic, political and regulatory developments, competition from other sources of energy, and the other items discussed under the caption "Risk Factors" in Item 1A of our Annual Report on Form 10 K for the period ended December 31, 2017. Oil and gas prices historically have been volatile and may fluctuate widely in the future. The following table highlights the quarterly average NYMEX price trends for crude oil and natural gas prices since the first quarter of 2016:

	2016				2017				2018		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
de	$ 33.51	$ 45.60	$ 44.94	$ 49.33	$ 51.86	$ 48.29	$ 48.19	$ 55.39	$ 62.89	$ 67.90	$ 69
ural	$ 2.06	$ 1.98	$ 2.93	$ 2.98	$ 3.07	$ 3.09	$ 2.89	$ 2.87	$ 3.13	$ 2.77	$ 2.8

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our oil and gas reserve quantities. Substantial and extended declines in oil, NGL and natural gas prices have resulted, and may result, in impairments of our proved oil and gas properties or undeveloped acreage and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. In addition, lower commodity prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of our lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding under our credit agreement. Alternatively, higher oil prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives.

2018 Highlights and Future Considerations

Operational Highlights

Northern Rocky Mountains – Williston Basin

Our properties in the Williston Basin of North Dakota and Montana target the Bakken and Three Forks formations. Net production from the Williston Basin averaged 106.9 MBOE/d for the third quarter of 2018, representing a 3% increase from 103.5 MBOE/d in the second quarter of 2018. Across our acreage in the Williston Basin, we have implemented new completion designs which utilize cemented liners, plug-and-perf technology, new diversion technology and both hybrid and slickwater fracture stimulation methods. We are creating custom completion designs for each well utilizing the optimum proppant, fluid and frac stages to increase our return on investment. As of September 30, 2018, we had five rigs active in the Williston Basin. We drilled 34 wells and put 45 wells on production in this area during the third quarter of 2018.

Central Rocky Mountains – Denver-Julesburg Basin

Our Redtail field in the Denver-Julesburg Basin ("DJ Basin") in Weld County, Colorado targets the Niobrara and Codell/Fort Hays formations. Net production from the Redtail field averaged 21.2 MBOE/d in the third quarter of 2018, representing a 4% decrease from 22.0 MBOE/d in the second quarter of 2018. We have established production in the Niobrara "A", "B" and "C" zones and the Codell/Fort Hays formations. During 2017, we completed and brought on production a significant portion of our drilled uncompleted well inventory ("DUCs") from yearend 2016. During the fourth quarter of 2017, based on the recent and comparative well performance results of the DJ Basin to the Williston Basin, our management decided to concentrate development activities during 2018 in the Williston Basin. We completed 22 DUCs in our Redtail field during the first half of 2018 and plan to cease additional development activity in this area for the remainder of 2018.

Our Redtail gas plant processes the associated gas produced from our wells in this area, and has a current inlet capacity of 50 MMcf/d. As of September 30, 2018, the plant was processing over 33 MMcf/d.

Financing Highlights

On January 26, 2018, we paid $1.0 billion to redeem all of the then outstanding $961 million aggregate principal amount of our 2019 Senior Notes, which payment consisted of the 102.976% redemption price plus all accrued and unpaid interest on the notes. We financed the redemption with proceeds from the issuance of our 2026 Senior Notes and borrowings under our credit agreement. Refer to the "Long-Term Debt" footnote in the notes to condensed consolidated financial statements for more information on this financing transaction.

Acquisition and Divestiture Highlights

On July 31, 2018, we completed the acquisition of approximately 54,800 net acres in the Williston Basin, including interests in 117 producing oil and gas wells and undeveloped acreage located in Richland County, Montana and McKenzie County, North Dakota for an aggregate purchase price of $130 million (before closing adjustments).

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Results of Operations

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017

	Nine Months Ended September 30,	
	2018	2017
Net production		
Oil (MMBbl)	23.4	21.3
NGLs (MMBbl)	5.6	5.0
Natural gas (Bcf)	34.7	30.2
Total production (MMBOE)	34.8	31.3
Net sales (in millions)		
Oil (1)	$ 1,448.3	$ 887.1
NGLs	114.0	67.1
Natural gas	45.9	52.8
Total oil, NGL and natural gas sales	$ 1,608.2	$ 1,007.0
Average sales prices		
Oil (per Bbl) (1)	$ 61.99	$ 41.73
Effect of oil hedges on average price (per Bbl)	(6.01)	0.50
Oil net of hedging (per Bbl)	$ 55.98	$ 42.23
Weighted average NYMEX price (per Bbl) (2)	$ 66.80	$ 49.51
NGLs (per Bbl)	$ 20.32	$ 13.33
Natural gas (per Mcf)	$ 1.32	$ 1.75
Weighted average NYMEX price (per MMBtu) (2)	$ 2.93	$ 3.01
Costs and expenses (per BOE)		
Lease operating expenses	$ 7.91	$ 8.53
Production taxes	$ 3.67	$ 2.76
Depreciation, depletion and amortization	$ 16.81	$ 21.49
General and administrative	$ 2.73	$ 2.96

(1) Before consideration of hedging transactions.
(2) Average NYMEX pricing weighted for monthly production volumes.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $601 million to $1.6 billion when comparing the first nine months of 2018 to the same period in 2017. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil, NGL and natural gas sales volumes increased 10%, 11% and 15%, respectively, between periods. The oil volume increase between periods was primarily attributable to new wells drilled and completed in the Williston Basin and DJ Basin which added 6,600 MBbl and 2,980 MBbl, respectively, of oil production during the first nine months of 2018 as compared to the first nine months of 2017. These increases were partially offset by normal field production decline across several of our areas, as well as 2017 property divestitures which negatively impacted oil production in the first nine months of 2018 by 1,835 MBbl. The NGL volume increase between periods generally relates to new wells drilled and completed in the Williston Basin and DJ Basin over the last twelve months, as well as additional volumes processed as more wells were connected to gas processing plants in the Williston Basin in an effort to increase our overall gas capture rate in this area and reduce flared volumes. Many of the new Williston Basin wells are in areas with higher gas-to-oil production ratios than previously drilled areas. These NGL volume increases were partially offset by normal field production decline across several of our areas. The gas volume increase between periods was primarily due to new wells drilled and completed at our Williston Basin and DJ Basin properties which resulted in 8,670 MMcf and 4,205 MMcf, respectively, of additional gas volumes during the first nine months of 2018 as compared to the first nine months of 2017. These increases were partially offset by normal field production decline across several of our areas, as well as 2017 property divestitures which negatively impacted gas production in the first nine months of 2018 by 340 MMcf.

In addition to the above production-related increases in net revenue, there were also increases in the average sales price realized for oil and NGLs in the first nine months of 2018 compared to 2017. Our average price for oil (before the effects of hedging) increased 49% and our average price for NGLs increased 52%, while our average price for natural gas decreased 25% between periods. Our average sales price realized for oil is impacted by deficiency payments we were making under two physical delivery contracts at our Redtail field due to our inability to meet the minimum volume commitments under these contracts. During the nine months ended September 30, 2018 and 2017, our total average sales price realized for oil was $1.17 per Bbl and $2.46 per Bbl lower, respectively, as a result of these deficiency payments. On February 1, 2018, we paid $61 million to the counterparty to one of these Redtail delivery contracts to settle all future minimum volume commitments under the agreement. The remaining agreement will continue to negatively impact the price we receive for oil from our Redtail field through April 2020, when the contract terminates. Our average sales price for oil was further impacted by the adoption of FASB ASC Topic 606 – Revenue from Contracts with Customers (“ASC 606”), which resulted in an increase of $0.48 per Bbl for the nine months ended September 30, 2018. In addition, the adoption of ASC 606 negatively impacted our average sales price for NGLs and natural gas by $3.26 per Bbl and $0.68 per Mcf, respectively, for the nine months ended September 30, 2018. Refer to the “Revenue Recognition” footnote in the condensed consolidated financial statements for more information on the impact of this new standard.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during the first nine months of 2018 were $275 million, a $7 million increase over the same period in 2017. This increase was primarily due to new wells put on production in the Williston Basin and the DJ Basin during 2018, largely offset by the impact of adopting ASC 606 effective January 1, 2018, which reduced LOE by $31 million for the nine months ended September 30, 2018, as well as the elimination of $22 million of LOE attributable to properties that we divested during 2017. Refer to the “Revenue Recognition” footnote in the condensed consolidated financial statements for more information on the impact of ASC 606.

Our lease operating expenses on a BOE basis, however, decreased when comparing the first nine months of 2018 to the same 2017 period. LOE per BOE amounted to $7.91 during the first nine months of 2018, which represents a decrease of $0.62 per BOE (or 7%) from the first nine months of 2017. This decrease was mainly due to higher overall production volumes between periods, partially offset by the overall increase in LOE expense discussed above.

Production Taxes. Our production taxes during the first nine months of 2018 were $128 million, a $41 million increase over the same period in 2017, which was primarily due to higher sales revenue between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 7.9% and 8.6% for the first nine months of 2018 and 2017, respectively. Our production tax rate for 2018 was less than the rate for 2017 due to successful wells completed during the past twelve months in Colorado, which has a 5% tax rate, as well as severance tax refunds received during the first nine months of 2018.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense decreased $89 million in 2018 as compared to the first nine months of 2017. The components of our DD&A expense were as follows (in thousands):

	Nine Months Ended September 30,

	2018	2017
Depletion	$ 571,121	$ 657,152
Depreciation	4,733	5,634
Accretion of asset retirement obligations	8,365	10,502
Total	$ 584,219	$ 673,288

DD&A decreased between periods primarily due to $86 million in lower depletion expense, consisting of a $142 million decrease related to a lower depletion rate between periods, partially offset by a $56 million increase due to higher overall production volumes during the first nine months of 2018. On a BOE basis, our overall DD&A rate of $16.81 for the first nine months of 2018 was 22% lower than the rate of $21.49 for the same period in 2017. The primary factors contributing to this lower DD&A rate were (i) impairment write-downs on proved oil and gas properties recognized in the fourth quarter of 2017 and (ii) an increase to proved developed reserves over the last twelve months (excluding the effect of divestitures).

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Exploration and Impairment Costs. Our exploration and impairment costs decreased $25 million for the first nine months of 2018 as compared to the same period in 2017. The components of our exploration and impairment expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2018	2017
Exploration	$ 13,399	$ 19,523
Impairment	25,612	44,270
Total	$ 39,011	$ 63,793

Exploration costs decreased $6 million during the first nine months of 2018 as compared to the same period in 2017 primarily due to decreased activity at our Redtail field, as well as a decrease in geology-related general and administrative expenses between periods.

Impairment expense for the first nine months of 2018 and 2017 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. The decrease of $19 million between periods primarily relates to the sale of certain unproved properties during the third quarter of 2017, as well as $12 million of impairment write-downs of undeveloped acreage costs in the fourth quarter of 2017 for leases where we have no future plans to drill.

General and Administrative Expenses. We report general and administrative ("G&A") expenses net of third-party reimbursements and internal allocations. The components of our G&A expenses were as follows (in thousands):

	Nine Months Ended September 30,	
	2018	2017
General and administrative expenses	$ 168,701	$ 170,884
Reimbursements and allocations	(73,719)	(78,240)
General and administrative expenses, net	$ 94,982	$ 92,644

G&A expense remained fairly consistent when comparing the first nine months of 2018 to the same 2017 period, however, our G&A expenses on a BOE basis decreased between periods. G&A expense per BOE amounted to $2.73 during the first nine months of 2018, which represents a decrease of $0.23 per BOE (or 8%) from the first nine months of 2017. This decrease was mainly due to higher overall production volumes between periods.

Derivative Loss, Net. Our commodity derivative contracts and embedded derivatives are marked to market each quarter with fair value gains and losses recognized immediately in earnings as derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment to or from the counterparty. Derivative loss, net amounted to $177 million for the nine months ended September 30, 2018, which consisted of a $179 million loss on our costless collar and swap commodity derivative contracts resulting from the significant upward shift in the futures curve of forecasted commodity prices ("forward price curve") for crude oil from January 1, 2018 (or the 2018 date on which new contracts were entered into) to September 30, 2018, partially offset by a $2 million fair value gain on our long-term crude oil sales and delivery contract. Derivative loss, net amounted to a loss of $47 million for the nine months ended September 30, 2017, which consisted of a $48 million fair value loss on our long-term crude oil sales and delivery contract and a $19 million fair value loss on embedded derivatives, partially offset by a $20 million gain on our costless collar commodity derivative contracts resulting from the less significant downward shift in the same forward price curve from January 1, 2017 (or the 2017 date on which prior year contracts were entered into) to September 30, 2017.

Refer to Item 3, “Quantitative and Qualitative Disclosures about Market Risk”, for a list of our outstanding commodity derivative contracts as of October 1, 2018.

Loss on Sale of Properties. During the first nine months of 2017, we sold our interests in the Fort Berthold Indian Reservation area assets (the “FBIR Assets”) for net cash proceeds of $501 million, which resulted in a pre-tax loss on sale of $402 million. Refer to the “Acquisitions and Divestitures” footnote in the condensed consolidated financial statements for more information on this transaction. There were no other property divestitures resulting in a significant gain or loss on sale during the first nine months of 2018 or 2017.

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Interest Expense. The components of our interest expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2018	2017
Notes	$ 115,109	$ 99,675
Amortization of debt issue costs, discounts and premiums	22,976	22,927
Credit agreement	10,431	20,054
Other	1,042	985
Total	$ 149,558	$ 143,641

The increase in interest expense of $6 million between periods was mainly attributable to higher interest costs incurred on our notes during the first nine months of 2018 as compared to the first nine months of 2017. The $15 million increase in note interest was primarily due to $50 million of interest incurred on the 2026 Senior Notes issued in December 2017, partially offset by a $33 million reduction in interest related to the redemption of the 2019 Notes in January 2018. Refer to the “Long-Term Debt” footnote in the notes to condensed consolidated financial statements for more information on these debt transactions. The increase in note interest was partially offset by a $10 million decrease in interest incurred on the credit agreement between periods due to a lower average outstanding balance. Our weighted average borrowings outstanding during the first nine months of 2018 were $126 million compared to $482 million during the first nine months of 2017.

Our weighted average debt outstanding during the first nine months of 2018 was $3.1 billion versus $3.3 billion for the first nine months of 2017. Our weighted average effective cash interest rate was 5.5% during the first nine months of 2018 compared to 4.8% for the first nine months of 2017.

Loss on Extinguishment of Debt. During the first nine months of 2018, we redeemed all of the remaining $961 million aggregate principal amount of 2019 Senior Notes and recognized a $31 million loss on extinguishment of debt. During the first nine months of 2017, we redeemed all of the remaining $275 million aggregate principal amount of 2018 Senior Subordinated Notes and recognized a $2 million loss on extinguishment of debt. Refer to the “Long-Term Debt” footnote in the notes to condensed consolidated financial statements for more information on these debt transactions.

Income Tax Benefit. As of December 31, 2017, we recorded a full valuation allowance on our deferred tax assets. Accordingly, we did not recognize any income tax expense or benefit during the first nine months of 2018, as compared to an income tax benefit of $320 million for the first nine months of 2017.

Our overall effective tax rate of 42.1% for the first nine months of 2017 was higher than the U.S. statutory income tax rate in effect during 2017 primarily due to state income taxes and the partial release of a valuation allowance on net operating losses totaling $41 million in connection with the sale of the FBIR Assets in the third quarter of 2017.

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Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017

	Three Months Ended September 30,	
	2018	2017
Net production		
Oil (MMBbl)	7.9	7.1
NGLs (MMBbl)	1.9	1.8
Natural gas (Bcf)	12.1	10.2
Total production (MMBOE)	11.8	10.5
Net sales (in millions)		
Oil (1)	$ 511.9	$ 289.4
NGLs	42.5	21.3
Natural gas	12.3	13.5
Total oil, NGL and natural gas sales	$ 566.7	$ 324.2
Average sales prices		
Oil (per Bbl) (1)	$ 64.70	$ 41.03
Effect of oil hedges on average price (per Bbl)	(7.88)	0.66
Oil net of hedging (per Bbl)	$ 56.82	$ 41.69
Weighted average NYMEX price (per Bbl) (2)	$ 69.52	$ 48.24
NGLs (per Bbl)	$ 22.22	$ 12.06
Natural gas (per Mcf)	$ 1.02	$ 1.32
Weighted average NYMEX price (per MMBtu) (2)	$ 2.88	$ 2.89
Cost and expenses (per BOE)		
Lease operating expenses	$ 7.81	$ 8.61
Production taxes	$ 3.93	$ 2.61
Depreciation, depletion and amortization	$ 16.64	$ 20.23
General and administrative	$ 2.69	$ 2.86

(1) Before consideration of hedging transactions.
(2) Average NYMEX pricing weighted for monthly production volumes.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $243 million to $567 million when comparing the third quarter of 2018 to the same period in 2017. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil, NGL and natural gas sales volumes increased 12%, 8% and 18%, respectively, between periods. The oil volume increase between periods was primarily attributable to new wells drilled and completed in the Williston Basin and DJ Basin which added 2,255 MBbl and 790 MBbl, respectively, of oil production during the third quarter of 2018 as compared to the third quarter of 2017. These increases were partially offset by normal field production decline across several of our areas, as well as 2017 property divestitures which negatively impacted oil production in the third quarter of 2018 by 495 MBbl. The NGL volume increase between periods generally relates to new wells drilled and completed in the Williston Basin and DJ Basin over the last twelve months, as well as additional volumes processed as more wells were connected to gas processing plants in the Williston Basin in an effort to increase our overall gas capture rate in this area and reduce flared volumes. Many of the new Williston Basin wells are in areas with higher gas-to-oil production ratios than previously drilled areas. These NGL volume increases were largely offset by normal field production decline across several of our areas. The gas volume increase between periods was primarily due to new wells drilled and completed at our Williston Basin and DJ Basin properties which resulted in 3,055 MMcf and 1,355 MMcf, respectively, of additional gas volumes during the third quarter of 2018 as compared to the third quarter of 2017. These increases were partially offset by normal field production decline across several of our areas, as well as 2017 property divestitures which negatively impacted gas production in the third quarter of 2018 by 101 MMcf.

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In addition to the above production-related increases in net revenue, there were also increases in the average sales price realized for oil and NGLs in the third quarter of 2018 compared to 2017. Our average price for oil (before the effects of hedging) increased 58% and our average price for NGLs increased 84% between periods, while our average price for natural gas decreased 23% between periods. Our average sales price realized for oil is impacted by deficiency payments we were making under two physical delivery contracts at our Redtail field due to our inability to meet the minimum volume commitments under these contracts. During the three months ended September 30, 2018 and 2017, our total average sales price realized for oil was $1.30 per Bbl and $2.46 per Bbl lower, respectively, as a result of these deficiency payments. On February 1, 2018, we paid $61 million to the counterparty to one of these Redtail delivery contracts to settle all future minimum volume commitments under the agreement. The remaining agreement will continue to negatively impact the price we receive for oil from our Redtail field through April 2020, when the contract terminates. Our average sales price for oil was further impacted by the adoption of ASC 606, which resulted in an increase of $0.55 per Bbl for the third quarter of 2018. In addition, the adoption of ASC 606 negatively impacted our average sales price for NGLs and natural gas by $3.35 per Bbl and $0.77 per Mcf, respectively, for the third quarter of 2018. Refer to the “Revenue Recognition” footnote in the condensed consolidated financial statements for more information on the impact of this new standard.

Lease Operating Expenses. Our LOE during the third quarter of 2018 were $92 million, a $2 million increase over the same period in 2017. This increase was primarily due to new wells put on production in the Williston Basin and the DJ Basin during 2018, largely offset by the impact of adopting ASC 606 effective January 1, 2018, which reduced LOE by $11 million during the three months ended September 30, 2018, as well as the elimination of $6 million of LOE attributable to properties that we divested during 2017. Refer to the “Revenue Recognition” footnote in the condensed consolidated financial statements for more information on the impact of ASC 606.

Our lease operating expenses on a BOE basis, however, decreased when comparing the third quarter of 2018 to the same 2017 period. LOE per BOE amounted to $7.81 during the third quarter of 2018, which represents a decrease of $0.80 per BOE (or 9%) from the third quarter of 2017. This decrease was mainly due to higher overall production volumes between periods, partially offset by the overall increase in LOE expense discussed above.

Production Taxes. Our production taxes during the third quarter of 2018 were $47 million, a $19 million increase over the same period in 2017, which was primarily due to higher sales revenue between periods. Our production taxes, however, are generally calculated as a percentage of net sales revenue before the effects of hedging, and this percentage on a company-wide basis was 8.2% and 8.5% for the third quarter of 2018 and 2017, respectively. Our production tax rate for 2018 was less than the rate for 2017 due to successful wells completed during the past twelve months in Colorado, which has a 5% tax rate.

Depreciation, Depletion and Amortization. Our DD&A expense decreased $16 million in 2018 as compared to the third quarter of 2017. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended September 30,	
	2018	2017
Depletion	$ 192,505	$ 207,555
Depreciation	1,590	1,898
Accretion of asset retirement obligations	2,911	3,393
Total	$ 197,006	$ 212,846

DD&A decreased between periods due to $15 million in lower depletion expense, consisting of a $36 million decrease related to a lower depletion rate between periods, partially offset by a $21 million increase due to higher overall production volumes during the third quarter of 2018. On a BOE basis, our overall DD&A rate of $16.64 for the third quarter of 2018 was 18% lower than the rate of $20.23 for the same period in 2017. The primary factors contributing to this lower DD&A rate were (i) impairment write-downs on proved oil and gas properties recognized in the fourth quarter of 2017, (ii) an increase to proved developed reserves over the last twelve months (excluding the effect of divestitures) and (iii) the impact of property divestitures over the past twelve months.

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Exploration and Impairment Costs. Our exploration and impairment costs decreased $7 million for the third quarter of 2018 as compared to the same period in 2017. The components of our exploration and impairment expense were as follows (in thousands):

	Three Months Ended September 30,	
	2018	2017
Exploration	$ 3,728	$ 7,033
Impairment	7,302	10,624
Total	$ 11,030	$ 17,657

Exploration costs decreased $3 million during the third quarter of 2018 as compared to the same period in 2017 primarily due to decreased activity at our Redtail field, as well as a decrease in geology-related general and administrative expenses between periods.

Impairment expense for the third quarter of 2018 and 2017 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. The decrease of $3 million between periods primarily relates to the sale of certain unproved properties during the third quarter of 2017, as well as $12 million of impairment write-downs of undeveloped acreage costs in the fourth quarter of 2017 for leases where we have no future plans to drill.

General and Administrative Expenses. We report G&A expenses net of third-party reimbursements and internal allocations. The components of our G&A expenses were as follows (in thousands):

	Three Months Ended September 30,	
	2018	2017
General and administrative expenses	$ 55,866	$ 56,061
Reimbursements and allocations	(23,965)	(25,977)
General and administrative expenses, net	$ 31,901	$ 30,084

G&A expense remained fairly consistent when comparing the third quarter of 2018 to the same 2017 period, however, our G&A expenses on a BOE basis decreased between periods. G&A expense per BOE amounted to $2.69 during the third quarter of 2018, which represents a decrease of $0.17 per BOE (or 6%) from the third quarter of 2017. This decrease was mainly due to higher overall production volumes between periods.

Derivative Loss, Net. Our commodity derivative contracts and embedded derivatives are marked to market each quarter with fair value gains and losses recognized immediately in earnings as derivative (gain) loss, net. Cash flow, however, is only impacted to the extent that settlements under these contracts result in making or receiving a payment to or from the counterparty. Derivative loss, net of $21 million for the three months ended September 30, 2018 related to our costless collar and swap commodity derivative contracts and resulted from the significant upward shift in the forward price curve for crude oil from July 1, 2018 (or the 2018 date on which new contracts were entered into) to September 30, 2018. Derivative loss, net amounted to $31 million for the three months ended September 30, 2017, which consisted of a $36 million loss on our costless collar commodity derivative contracts resulting from the more significant upward shift in the forward price curve for crude oil from July 1, 2017 (or the 2017 date on which new contracts were entered into) to September 30, 2017, partially offset by a $5 million fair value gain on our long-term sales and delivery contract.

Refer to Item 3, “Quantitative and Qualitative Disclosures about Market Risk”, for a list of our outstanding commodity derivative contracts as of October 1, 2018.

Loss on Sale of Properties. During the third quarter of 2017, we sold our interests in the FBIR Assets for net cash proceeds of $501 million, which resulted in a pre-tax loss on sale of $402 million. There were no other property divestitures resulting in a significant gain or loss on sale during the third quarter of 2018 or 2017.

Interest Expense. The components of our interest expense were as follows (in thousands):

	Three Months Ended September 30,	
	2018	2017
Notes	$ 37,257	$ 32,712
Amortization of debt issue costs, discounts and premiums	7,634	7,705
Credit agreement	3,125	6,969
Other	312	307
Total	$ 48,328	$ 47,693

Interest expense remained relatively consistent when comparing the third quarter of 2018 to the same 2017 period, however note interest increased $5 million between periods. This increase was due to $17 million of interest incurred on the 2026 Senior Notes issued in December 2017, partially offset by a $12 million reduction in interest related to the redemption of the 2019 Notes in January 2018. Refer to the "Long-Term Debt" footnote in the notes to condensed consolidated financial statements for more information on these debt transactions.

Our weighted average debt outstanding during the third quarter of 2018 was $3.0 billion versus $3.3 billion for the third quarter of 2017. Our weighted average effective cash interest rate was 5.4% during the third quarter of 2018 compared to 4.8% for the third quarter of 2017.

Income Tax Benefit. As of December 31, 2017, we recorded a full valuation allowance on our deferred tax assets. Accordingly, we did not recognize any income tax expense or benefit during the third quarter of 2018, as compared to an income tax benefit of $242 million for the third quarter of 2017.

Our overall effective tax rate of 45.8% for the third quarter of 2017 was higher than the U.S. statutory income tax rate in effect during 2017 primarily due to state income taxes and the partial release of a valuation allowance on net operating losses totaling $41 million in connection with the sale of the FBIR Assets in the third quarter of 2017.

Liquidity and Capital Resources

Overview. At September 30, 2018, we had $14 million of cash on hand and $4.1 billion of equity, while at December 31, 2017, we had $879 million of cash on hand and $3.9 billion of equity. Cash on hand at December 31, 2017 consisted of the remaining proceeds from the issuance of our 2026 Senior Notes in December 2017 and was used to redeem the 2019 Notes in January 2018.

One of the primary sources of variability in our cash flows from operating activities is commodity price volatility, which we partially mitigate through the use of commodity hedge contracts. Oil accounted for 67% and 68% of our total production in the first nine months of 2018 and 2017, respectively. As a result, our operating cash flows are more sensitive to fluctuations in oil prices than they are to fluctuations in NGL or natural gas prices. As of October 1, 2018, we had derivative contracts covering the sale of approximately 68% of our forecasted oil production volumes for the remainder of 2018. For a list of all of our outstanding derivatives as of October 1, 2018, refer to Item 3, "Quantitative and Qualitative Disclosures about Market Risk".

During the first nine months of 2018, we generated $807 million of cash provided by operating activities, an increase of $517 million from the same period in 2017. Cash provided by operating activities increased primarily due to higher crude oil, NGL and natural gas production volumes, higher realized sales prices for oil and NGLs and lower exploration costs. These positive factors were partially offset by an increase in cash settlements paid on our derivative contracts, lower realized sales prices for natural gas, as well as higher production taxes, cash general and administrative expenses, lease operating expenses and cash interest expense during the first nine months of 2018 as compared to the same period in 2017. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and for more information on increases and decreases in certain expenses between periods.

During the first nine months of 2018, cash flows from operating activities, cash on hand and $50 million of net borrowings under our credit agreement were used to finance the redemption of the remaining $961 million of 2019 Senior Notes, including the redemption premium, $580 million of drilling and development expenditures and $140 million of oil and gas property acquisitions.

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Exploration and Development Expenditures. The following table details our exploration and development expenditures incurred by core area (in thousands):

	Nine Months Ended September 30,	
	2018	2017
Northern Rocky Mountains	$ 512,187	$ 465,789
Central Rocky Mountains	80,060	269,361
Other (1)	5,425	6,522
Total incurred	$ 597,672	$ 741,672

(1) Other primarily includes non-core oil and gas properties located in Colorado, Texas, Utah and Wyoming.

We continually evaluate our capital needs and compare them to our capital resources. Our 2018 exploration and development (“E&D”) budget is $750 million, which we expect to fund substantially with net cash provided by operating activities and cash on hand. The 2018 E&D budget represents a decrease from the $912 million incurred on E&D expenditures during 2017. We believe that should additional attractive acquisition opportunities arise or E&D expenditures exceed $750 million, we will be able to finance additional capital expenditures through agreements with industry partners, divestitures of certain oil and gas property interests, borrowings under our credit agreement or by accessing the capital markets. Our level of E&D expenditures is largely discretionary, and the amount of funds we devote to any particular activity may increase or decrease significantly depending on commodity prices, cash flows, available opportunities and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plan over the next 12 months and for the foreseeable future. With our expected cash flow streams, commodity price hedging strategies, current liquidity levels (including availability under our credit agreement), access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs and debt repayments, comply with our debt covenants, and meet other obligations that may arise from our oil and gas operations.

Credit Agreement. Whiting Oil and Gas, our wholly owned subsidiary, has a credit agreement with a syndicate of banks that as of September 30, 2018 had a borrowing base and aggregate commitments of $2.4 billion and $1.75 billion, respectively. As of September 30, 2018, we had $1.7 billion of available borrowing capacity under the credit agreement, which was net of $50 million of borrowings outstanding and $2 million in letters of credit outstanding.

The borrowing base under the credit agreement is determined at the discretion of our lenders, based on the collateral value of our proved reserves that have been mortgaged to such lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Upon a redetermination of our borrowing base, either on a periodic or special redetermination date, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of our debt outstanding under the credit agreement.

A portion of the revolving credit facility in an aggregate amount not to exceed $50 million may be used to issue letters of credit, for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of September 30, 2018, $48 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until maturity, when the credit agreement expires and all outstanding borrowings are due. Interest under the credit agreement accrues at our option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.5% per annum, or an adjusted LIBOR rate plus 1.0% per annum, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below.

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Additionally, we also incur commitment fees as set forth in the table below on the unused portion of the aggregate commitments of the lenders under the credit agreement.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. Except for limited exceptions, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of our restricted subsidiaries (as defined in the credit agreement). As of September 30, 2018, the credit agreement required us, as of the last day of any quarter, to maintain the following ratios (as defined in the credit agreement): (i) a consolidated current assets to consolidated current liabilities ratio (which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) a total debt to the last four quarters' EBITDAX ratio of not greater than 4.0 to 1.0. We were in compliance with our covenants under the credit agreement as of September 30, 2018.

For further information on the loan security related to our credit agreement, refer to the "Long-Term Debt" footnote in the notes to condensed consolidated financial statements.

Senior Notes and Senior Subordinated Notes. In December 2017, we issued at par $1.0 billion of 6.625% Senior Notes due January 2026 (the "2026 Senior Notes"). In March 2015, we issued at par $750 million of 6.25% Senior Notes due April 2023 (the "2023 Senior Notes"). In September 2013, we issued at par $1.1 billion of 5.0% Senior Notes due March 2019 (the "2019 Senior Notes") and $800 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400 million of 5.75% Senior Notes due March 2021 (collectively the "2021 Senior Notes" and together with the 2023 Senior Notes and the 2026 Senior Notes, the "Senior Notes"). In September 2010, we issued at par $350 million of 6.5% Senior Subordinated Notes due October 2018 (the "2018 Senior Subordinated Notes").

Exchange of Senior Notes and Senior Subordinated Notes for Convertible Notes. During 2016, we exchanged (i) $75 million aggregate principal amount of our 2018 Senior Subordinated Notes, (ii) $139 million aggregate principal amount of our 2019 Senior Notes, (iii) $326 million aggregate principal amount of our 2021 Senior Notes, and (iv) $342 million aggregate principal amount of our 2023 Senior Notes, for the same aggregate principal amount of convertible notes. Subsequently during 2016, all $882 million aggregate principal amount of these convertible notes was converted into approximately 21.6 million shares of our common stock pursuant to the terms of the notes.

Redemption of 2018 Senior Subordinated Notes. On February 2, 2017, we paid $281 million to redeem all of the then outstanding $275 million aggregate principal amount of our 2018 Senior Subordinated Notes, which payment consisted of the 100% redemption price plus all accrued and unpaid interest on the notes. We financed the redemption with borrowings under our credit agreement. As of March 31, 2017, no 2018 Senior Subordinated Notes remained outstanding.

Redemption of 2019 Senior Notes. On January 26, 2018, we paid $1.0 billion to redeem all of the then outstanding $961 million aggregate principal amount of our 2019 Senior Notes, which payment consisted of the 102.976% redemption price plus all accrued and unpaid interest on the notes. We financed the redemption with proceeds from the issuance of our 2026 Senior Notes and borrowings under our credit agreement. As of March 31, 2018, no 2019 Senior Notes remained outstanding.

2020 Convertible Senior Notes. In March 2015, we issued at par $1,250 million of 1.25% Convertible Senior Notes due April 2020 (the “2020 Convertible Senior Notes”). During 2016, we exchanged $688 million aggregate principal amount of our 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Subsequently during 2016, all $688 million

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aggregate principal amount of these mandatory convertible senior notes was converted into approximately 17.8 million shares of our common stock pursuant to the terms of the notes.

For the remaining $562 million aggregate principal amount of 2020 Convertible Senior Notes outstanding as of September 30, 2018, we have the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at our election. Our intent is to settle the principal amount of the 2020 Convertible Senior Notes in cash upon conversion. Prior to January 1, 2020, the 2020 Convertible Senior Notes will be convertible at the holder's option only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on June 30, 2015 (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading price per $1,000 principal amount of the 2020 Convertible Senior Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of our common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events. On or after January 1, 2020, the 2020 Convertible Senior Notes will be convertible at any time until the second scheduled trading day immediately preceding the April 1, 2020 maturity date of the notes. The notes will be convertible at a current conversion rate of 6.4102 shares of our common stock per $1,000 principal amount of the notes, which is equivalent to a current conversion price of approximately $156.00. The conversion rate will be subject to adjustment in some events. In addition, following certain corporate events that occur prior to the maturity date, we will increase, in certain circumstances, the conversion rate for a holder who elects to convert its 2020 Convertible Senior Notes in connection with such corporate event. As of September 30, 2018, none of the contingent conditions allowing holders of the 2020 Convertible Senior Notes to convert these notes had been met.

Note Covenants. The indentures governing the Senior Notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas' credit agreement. Additionally, these indentures contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, make certain other restricted payments, redeem or repurchase our capital stock, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance with these covenants as of September 30, 2018. However, a substantial or extended decline in oil, NGL or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of September 30, 2018 to make future payments under certain contracts, aggregated by category of contractual obligation, for the time periods specified below. This table does not include amounts payable under contracts where we cannot predict with accuracy the amount and timing of such payments, including any amounts we may be obligated to pay under our derivative contracts, as such payments are dependent upon the price of crude oil in effect at the time of settlement, and any penalties that may be incurred for underdelivery under our physical delivery contracts. For further information on these contracts refer to the "Derivative Financial Instruments" footnote in the notes to consolidated financial statements and "Delivery Commitments" in Item 2 of our Annual Report on Form 10 K for the period ended December 31, 2017.

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	Payments due by period (in thousands)				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$ 2,893,980	$ -	$ 1,435,684	$ 458,296	$ 1,000,000
Cash interest expense on debt (2)	771,789	157,888	277,913	184,349	151,639
Asset retirement obligations (3)	151,407	3,466	21,415	7,479	119,047
Water disposal agreement (4)	107,725	19,883	40,635	32,806	14,401
Purchase obligations (5)	17,226	7,656	9,570	-	-
Pipeline transportation agreements (6)	48,073	9,382	19,067	12,170	7,454
Drilling rig contracts (7)	16,071	14,894	1,177	-	-
Leases (8)	50,911	7,662	9,076	8,045	26,128
Total	$ 4,057,182	$ 220,831	$ 1,814,537	$ 703,145	$ 1,318,669

(1) Long-term debt consists of the principal amounts of the Senior Notes and the 2020 Convertible Senior Notes, as well as the outstanding borrowings on our credit agreement.

(2) Cash interest expense on the Senior Notes is estimated assuming no principal repayment until the due dates of the instruments. Cash interest expense on the 2020 Convertible Senior Notes is estimated assuming no principal repayments or conversions prior to maturity. Cash interest expense on the credit agreement is estimated assuming no principal borrowings or repayments through the April 2023 instrument due date and a fixed interest rate of 4.8%. Commitment fees on the credit agreement are estimated assuming no principal borrowings or repayments through the April 2023 instrument due date.

(3) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related plants, facilities and offshore platforms.

(4) We have one water disposal agreement which expires in 2024, whereby we have contracted for the transportation and disposal of the produced water from our Redtail field. Under the terms of the agreement, we are obligated to provide a minimum volume of produced water or else pay for any deficiencies at the price stipulated in the contract. As a result of our reduced development operations at our Redtail field, we have made and expect to continue to make deficiency payments under this contract.

(5) We have one take-or-pay purchase agreement which expires in 2020, whereby we have committed to buy certain volumes of water for use in the fracture stimulation process on wells we complete in our Redtail field. Under the terms of the agreement, we are obligated to purchase a minimum volume of water or else pay for any deficiencies at the price stipulated in the contract. As a result of our reduced development operations at our Redtail field, we have made and expect to continue to make deficiency payments under this contract.

(6) We have three pipeline transportation agreements with two different suppliers, expiring in 2022, 2024 and 2025. Under two of these contracts, we have committed to pay fixed monthly reservation fees on dedicated pipelines from our Redtail field for natural gas and NGL transportation capacity, plus a variable charge based on actual transportation volumes. The remaining contract contains a commitment to transport a minimum volume of crude oil via a certain oil gathering system or else pay for any deficiencies at a price stipulated in the contract. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts may exceed the minimum commitments presented above.

(7) As of September 30, 2018, we had three drilling rigs under long-term contracts, all of which expire in 2019. As of September 30, 2018, early termination of these contracts would require termination penalties of $12 million, which would be in lieu of paying the remaining drilling commitments under these contracts. The obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts may exceed the minimum commitments presented above.

(8) We lease 222,900 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2019, 44,500 square feet of office space in Midland, Texas expiring in 2020, and 81,875 square feet of office and warehouse space in North Dakota through 2023. In addition, we have entered into an agreement to lease 135,175 square feet of administrative office space in Denver beginning on or before November 1, 2019, which will replace our current Denver office space. We have sublet the

majority of our office space in Midland, Texas to a third party for the remaining lease term. The offsetting rental income has not been included in the table above.
Based on current oil and natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with cash on hand and amounts available under our credit agreement, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operating, development and exploration activities.

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to “Adopted and Recently Issued Accounting Pronouncements” within the “Basis of Presentation” footnote and the “Revenue Recognition” footnote in the notes to condensed consolidated financial statements.

Critical Accounting Policies and Estimates

Information regarding critical accounting policies and estimates is contained in Item 7 of our Annual Report on Form 10 K for the fiscal year ended December 31, 2017. The following is a material update to such critical accounting policies and estimates:

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

We adopted FASB ASC Topic 606 – Revenue from Contracts with Customers effective January 1, 2018 using the modified retrospective approach. Refer to the “Basis of Presentation” and “Revenue Recognition” footnotes in the notes to condensed consolidated financial statements for more information on this new accounting standard.

Effects of Inflation and Pricing

As a result of the sustained depressed commodity price environment from 2015 through 2017, we have experienced lower costs due to a decrease in demand for oil field products and services. Although prices have begun to recover during the first nine months of 2018, the cost of oil field goods and services has remained relatively consistent with 2017 levels. The oil and gas industry is very cyclical, and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts 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 not adjust downward in proportion to prices. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase in the near term, higher demand in the industry could result in increases in the costs of materials, services and personnel.

Forward-Looking Statements

This report contains statements that we believe to be "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we "expect", "intend", "plan", "estimate", "anticipate", "believe" or "should" or the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

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These risks and uncertainties include, but are not limited to: declines in, or extended periods of low oil, NGL or natural gas prices; our level of success in exploration, development and production activities; risks related to our level of indebtedness, ability to comply with debt covenants and periodic redeterminations of the borrowing base under our credit agreement; impacts to financial statements as a result of impairment write-downs; our ability to successfully complete asset dispositions and the risks related thereto; revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures; inaccuracies of our reserve estimates or our assumptions underlying them; risks relating to any unforeseen liabilities of ours; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations; federal and state initiatives relating to the regulation of hydraulic fracturing and air emissions; unforeseen underperformance of or liabilities associated with acquired properties; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; availability of, and risks associated with, transport of oil and gas; our ability to drill producing wells on undeveloped acreage prior to its lease expiration; shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and completion services; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; the potential impact of changes in laws, including tax reform, that could have a negative effect on the oil and gas industry; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry; cyber security attacks or failures of our telecommunication systems; and other risks described under the caption “Risk Factors” in Item 1A of our Annual Report on Form 10 K for the period ended December 31, 2017. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Quarterly Report on Form 10 Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

The price we receive for our oil and gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Crude 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. Historically, the markets for oil and gas have been volatile, and these markets will likely continue to be volatile in the future. Based on production for the first nine months of 2018, our income before income taxes for the nine months ended September 30, 2018 would have moved up or down \$145 million for each 10% change in oil prices per Bbl, \$11 million for each 10% change in NGL prices per Bbl and \$5 million for each 10% change in natural gas prices per Mcf.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars and swaps, although we evaluate and have entered into other forms of derivative instruments as well. Currently, we do not apply hedge accounting, and therefore all changes in commodity derivative fair values are recorded immediately to earnings.

Crude Oil Costless Collars and Swaps. The collared hedges shown in the table below have the effect of providing a protective floor while allowing us to share in upward pricing movements. The three-way collars, however, do not provide complete protection against declines in crude oil prices due to the fact that when the market price falls below the sub-floor, the minimum price we would receive would be NYMEX plus the difference between the floor and the sub-floor. While these hedges are designed to reduce our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. The fair value of these crude oil costless collars at September 30, 2018 was a net liability of \$95 million. A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of September 30, 2018 would cause an increase of \$70 million or a decrease of $56 million, respectively, in this fair value liability.

The swap contracts shown in the table below entitle us to receive settlement from the counterparty in amounts, if any, by which the settlement price for the applicable calculation period is less than the fixed price, or to pay the counterparty if the settlement price for the applicable calculation period is more than the fixed price. While the fixed-price swaps are designed to decrease our exposure to downward price movements, they also have the effect of limiting the benefit of upward price movements. The fair value of these swaps at September 30, 2018 was a net liability of $13 million. A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of September 30, 2018 would cause an increase or decrease, respectively, of $9 million in this fair value liability.

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Our outstanding commodity derivative contracts as of October 1, 2018 are summarized below:

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Price
				Sub-Floor/Floor/Ceiling
Three-way collars (1)	Crude oil	10/2018 to 12/2018	1,450,000	\$37.07/\$47.07/\$57.30
				Fixed Price
Swaps	Crude oil	10/2018 to 12/2018	400,000	\$61.74
				Floor/Ceiling
Collars	Crude oil	01/2019 to 03/2019	1,100,000	\$50.91/\$75.55
	Crude oil	04/2019 to 06/2019	1,100,000	\$50.91/\$75.55
	Crude oil	07/2019 to 09/2019	550,000	\$51.82/\$80.33
	Crude oil	10/2019 to 12/2019	550,000	\$51.82/\$80.33

(1) A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price.

Interest Rate Risk

Our quantitative and qualitative disclosures about interest rate risk related to our credit agreement, senior notes and convertible notes are included in Item 7A of our Annual Report on Form 10 K for the fiscal year ended December 31, 2017 and have not materially changed since that report was filed.

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a 15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our Senior Vice President and Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a 15(e) under the Exchange Act) as of September 30, 2018. Based upon their evaluation of these disclosure controls and procedures, the Chairman, President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer concluded that the disclosure controls and procedures were effective as of September 30, 2018 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended September 30, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

We are subject to litigation claims and governmental and regulatory proceedings from time to time. While the outcome of these lawsuits and claims cannot be predicted with certainty, it is management's opinion that the loss for any litigation matters and claims we are involved in that are reasonably possible to occur will not have a material adverse effect, individually or in the aggregate, on our consolidated financial position, cash flows or results of operations.

As noted in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2018, we entered into a settlement agreement with the Colorado Department of Public Health and Environment in June 2018.

Item 1A. Risk Factors

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10 K for the fiscal year ended December 31, 2017. No material change to such risk factors has occurred during the nine months ended September 30, 2018.

Item 6. Exhibits

The exhibits listed in the accompanying index to exhibits are filed as part of this Quarterly Report on Form 10 Q.

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(10.1)	Letter Agreement, dated August 24, 2018, Amending Outstanding Restricted Stock and Performance Share Awards and the Executive Employment and Severance Agreement [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on August 30, 2018 (File No. 001-31899)].
(10.2)	Form of Restricted Stock Unit Award Agreement (Stock-Settled) [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on August 30, 2018 (File No. 001-31899)].
(10.3)	Form of Performance Share Unit Award Agreement [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on August 30, 2018 (File No. 001-31899)].
(31.1)	Certification by the Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Senior Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Senior Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
(101)	The following materials from Whiting Petroleum Corporation's Quarterly Report on Form 10 Q for the quarter ended September 30, 2018 are filed herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets as of September 30, 2018 and December 31, 2017, (ii) the Condensed Consolidated Statements of Operations for the Three and Nine Months Ended September 30, 2018 and 2017, (iii) the Condensed Consolidated Statements of Cash Flows for the Nine Months Ended September 30, 2018 and 2017, (iv) the Condensed Consolidated Statements of Equity for the Nine Months Ended September 30, 2018 and 2017 and (v) Notes to Condensed Consolidated Financial Statements.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on this 31st day of October, 2018.

WHITING PETROLEUM CORPORATION

By /s/ Bradley J. Holly
Bradley J. Holly
Chairman, President and Chief Executive Officer

By /s/ Michael J. Stevens
Michael J. Stevens
Senior Vice President and Chief Financial Officer

By /s/ Sirikka R. Lohoefener
Sirikka R. Lohoefener
Controller and Treasurer