WHITING PETROLEUM CORP
Form 10-Q
October 27, 2016
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, 2016

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.)
	80290 2300

1700 Broadway, Suite 2300
Denver, Colorado
(Address of principal executive offices) (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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). Yes No

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

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 14, 2016: 284,343,983 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:

“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 or CO2.

“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.

“CO2” Carbon dioxide.

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

“EOR” Enhanced oil recovery.

“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.

“FASB ASC” The Financial Accounting Standards Board Accounting Standards Codification.

“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.

“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.

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“LIBOR” London interbank offered rate.

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

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet, used in reference to natural gas or CO_2.

“MMBbl” One million Bbl.

“MMBOE” One million BOE.

“MMcf” One million cubic feet, used in reference to natural gas or CO_2.

“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.

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.

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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. Consolidated Financial Statements

WHITING PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS (unaudited)

(in thousands, except share and per share data)

	September 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,329	$ 16,053
Accounts receivable trade, net	216,378	332,428
Derivative assets	34,054	158,729
Prepaid expenses and other	17,877	27,980
Total current assets	286,638	535,190
Property and equipment:		
Oil and gas properties, successful efforts method	13,721,164	13,904,525
Other property and equipment	135,788	168,277
Total property and equipment	13,856,952	14,072,802
Less accumulated depreciation, depletion and amortization	(4,188,500)	(3,323,102)
Total property and equipment, net	9,668,452	10,749,700
Other long-term assets	110,654	104,195
TOTAL ASSETS	$ 10,065,744	$ 11,389,085
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 41,382	$ 77,276
Revenues and royalties payable	138,075	179,601
Accrued capital expenditures	45,702	94,105
Accrued interest	9,052	62,661
Accrued lease operating expenses	34,260	55,291
Accrued liabilities and other	60,598	50,261
Taxes payable	45,868	47,789
Accrued employee compensation and benefits	23,007	32,829
Total current liabilities	397,944	599,813
Long-term debt	4,085,629	5,197,704

Deferred income taxes	738,432	593,792
Asset retirement obligations	164,289	155,550
Deferred gain on sale	38,471	48,974
Other long-term liabilities	36,960	34,664
Total liabilities	5,461,725	6,630,497
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 600,000,000 shares authorized; 289,676,901 issued and 284,343,983 outstanding as of September 30, 2016 and 206,441,303 issued and 204,147,647 outstanding as of December 31, 2015	290	206
Additional paid-in capital	5,671,074	4,659,868
Retained earnings (accumulated deficit)	(1,075,311)	90,530
Total Whiting shareholders' equity	4,596,053	4,750,604
Noncontrolling interest	7,966	7,984
Total equity	4,604,019	4,758,588
TOTAL LIABILITIES AND EQUITY	$ 10,065,744	$ 11,389,085

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

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
REVENUES AND OTHER INCOME:				
Oil, NGL and natural gas sales	$ 315,554	$ 504,155	$ 942,287	$ 1,674,530
Loss on sale of properties	(189,934)	(359)	(193,729)	(61,937)
Amortization of deferred gain on sale	3,490	3,666	11,111	13,240
Interest income and other	115	579	1,146	1,449
Total revenues and other income	129,225	508,041	760,815	1,627,282
COSTS AND EXPENSES:				
Lease operating expenses	87,982	125,575	307,530	435,315
Production taxes	26,372	44,303	79,125	145,410
Depreciation, depletion and amortization	284,569	316,147	900,877	922,077
Exploration and impairment	24,293	1,690,679	85,565	1,829,160
Goodwill impairment	-	869,713	-	869,713
General and administrative	33,908	44,821	112,227	133,788
Interest expense	84,578	84,551	245,145	247,984
(Gain) loss on extinguishment of debt	(46,541)	-	42,236	5,634
Derivative gain, net	(30,432)	(207,783)	(28,432)	(115,215)
Total costs and expenses	464,729	2,968,006	1,744,273	4,473,866
LOSS BEFORE INCOME TAXES	(335,504)	(2,459,965)	(983,458)	(2,846,584)
INCOME TAX EXPENSE (BENEFIT):				
Current	113	(422)	115	(357)
Deferred	357,438	(594,425)	182,286	(725,686)
Total income tax expense (benefit)	357,551	(594,847)	182,401	(726,043)
NET LOSS	(693,055)	(1,865,118)	(1,165,859)	(2,120,541)
Net loss attributable to noncontrolling interests	3	10	18	48
NET LOSS AVAILABLE TO COMMON SHAREHOLDERS	$ (693,052)	$ (1,865,108)	$ (1,165,841)	$ (2,120,493)
LOSS PER COMMON SHARE:				
Basic	$ (2.47)	$ (9.14)	$ (4.92)	$ (11.01)
Diluted	$ (2.47)	$ (9.14)	$ (4.92)	$ (11.01)
WEIGHTED AVERAGE SHARES OUTSTANDING:				

Basic	280,418	204,143	237,100	192,549
Diluted	280,418	204,143	237,100	192,549

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

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (1,165,859)	$ (2,120,541)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	900,877	922,077
Deferred income tax expense (benefit)	182,286	(725,686)
Amortization of debt issuance costs, debt discount and debt premium	72,389	33,058
Stock-based compensation	19,512	20,786
Amortization of deferred gain on sale	(11,111)	(13,240)
Loss on sale of properties	193,729	61,937
Undeveloped leasehold and oil and gas property impairments	45,906	1,721,160
Goodwill impairment	-	869,713
Exploratory dry hole costs	37	867
Loss on extinguishment of debt	42,236	5,634
Non-cash derivative loss	102,100	31,831
Other, net	(4,732)	(4,914)
Changes in current assets and liabilities:		
Accounts receivable trade, net	119,622	188,341
Prepaid expenses and other	9,063	45,787
Accounts payable trade and accrued liabilities	(104,579)	(59,181)
Revenues and royalties payable	(41,336)	(75,810)
Taxes payable	(1,885)	(563)
Net cash provided by operating activities	358,255	901,256
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and development capital expenditures	(434,794)	(2,146,681)
Acquisition of oil and gas properties	(3,605)	(25,018)
Other property and equipment	(6,744)	(7,123)
Proceeds from sale of oil and gas properties	304,291	338,507
Net cash used in investing activities	(140,852)	(1,840,315)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit agreement	1,050,000	2,450,000
Repayments of borrowings under credit agreement	(1,200,000)	(3,850,000)
Issuance of common stock	-	1,111,148
Issuance of 1.25% Convertible Senior Notes due 2020	-	1,250,000
Issuance of 6.25% Senior Notes due 2023	-	750,000

Partial redemption of 8.125% Senior Notes due 2019	-	(2,475)
Redemption of 5.5% Senior Notes due 2021	-	(353,500)
Redemption of 5.5% Senior Notes due 2022	-	(404,000)
Early conversion payments for New Convertible Notes	(41,919)	-
Debt and equity issuance costs	(22,499)	(54,420)
Proceeds from stock options exercised	-	3,048
Restricted stock used for tax withholdings	(709)	(1,111)
Net cash provided by (used in) financing activities	$ (215,127)	$ 898,690

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

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2016	2015
NET CHANGE IN CASH AND CASH EQUIVALENTS	$ 2,276	$ (40,369)
CASH AND CASH EQUIVALENTS:		
Beginning of period	16,053	78,100
End of period	$ 18,329	$ 37,731
NONCASH INVESTING ACTIVITIES:		
Accrued capital expenditures related to property additions	$ 62,416	$ 125,893
NONCASH FINANCING ACTIVITIES (1)		

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

(1) Refer to the “Long-Term Debt” footnote in the notes to consolidated financial statements for a discussion of (i) the Company’s exchange of senior notes and senior subordinated notes for convertible notes and the subsequent conversions of such notes, and (ii) the Company’s exchange of senior notes, convertible senior notes and senior subordinated notes for mandatory convertible notes and the subsequent conversions of such notes.

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF EQUITY (unaudited)

(in thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Whiting Shareholders' Equity	Noncontrolling Interest	Total Equity
BALANCES-January 1, 2015	168,346	$ 168	$ 3,385,094	$ 2,309,712	$ 5,694,974	$ 8,070	$ 5,703,044
Net loss	-	-	-	(2,120,493)	(2,120,493)	(48)	(2,120,541)
Issuance of common stock	37,000	37	1,100,000	-	1,100,037	-	1,100,037
Equity component of 2020 Convertible Senior Notes, net	-	-	144,755	-	144,755	-	144,755
Exercise of stock options	149	-	3,048	-	3,048	-	3,048
Restricted stock issued	1,216	1	(1)	-	-	-	-
Restricted stock forfeited	(217)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(38)	-	(1,111)	-	(1,111)	-	(1,111)
Stock-based compensation	-	-	20,786	-	20,786	-	20,786
BALANCES-September 30, 2015	206,456	$ 206	$ 4,652,571	$ 189,219	$ 4,841,996	$ 8,022	$ 4,850,018
BALANCES-January 1, 2016	206,441	$ 206	$ 4,659,868	$ 90,530	$ 4,750,604	$ 7,984	$ 4,758,588
Net loss	-	-	-	(1,165,841)	(1,165,841)	(18)	(1,165,859)
Issuance of common stock upon conversion of convertible notes	79,920	80	822,936	-	823,016	-	823,016
Reduction of equity component of 2020 Convertible Senior Notes upon extinguishment, net	-	-	(63,330)	-	(63,330)	-	(63,330)
Recognition of beneficial conversion features on convertible notes	-	-	232,801	-	232,801	-	232,801

Restricted stock issued	4,021	4	(4)	-	-	-	-
Restricted stock forfeited	(615)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(90)	-	(709)	-	(709)	-	(709)
Stock-based compensation	-	-	19,512	-	19,512	-	19,512
BALANCES-September 30, 2016	289,677	$ 290	$ 5,671,074	$ (1,075,311)	$ 4,596,053	$ 7,966	$ 4,604,019

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

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WHITING PETROLEUM CORPORATION

NOTES TO 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, acquisition, exploration and production 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 (formerly Kodiak Oil & Gas Corp., “Kodiak”), Whiting Resources Corporation (formerly Kodiak Oil & Gas (USA) Inc.) and Whiting Programs, Inc.

Consolidated Financial Statements—The unaudited 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 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, 2015. 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 2015 Annual Report on Form 10 K.

Earnings Per Share—Basic earnings per common share is calculated by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing adjusted net income available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of (i) convertible debt to be settled in shares, using the if-converted method and (ii) unvested restricted stock awards, outstanding stock options and contingently issuable shares of convertible debt to be settled in cash, all using the treasury stock method. When a loss from continuing operations exists, all dilutive securities and potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

Adopted and Recently Issued Accounting Pronouncements—In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Improvements To Employee Share-Based Payment Accounting (“ASU 2016-09”). The objective of this ASU is to simplify several aspects of the accounting for employee share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities and classification in the statement of cash flows. ASU 2016-09 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. Portions of this ASU must be applied prospectively while other portions may be applied either prospectively or retrospectively. Early adoption is permitted. The Company is currently evaluating the impact on its consolidated financial statements of adopting ASU 2016 09.

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. ASU 2016-02 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018 and should be applied using a modified retrospective approach. Early adoption is permitted. The Company is currently evaluating the impact on its consolidated financial statements of adopting ASU 2016 02.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (“ASU 2014 09”). The objective of ASU 2014-09 is to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and International Financial Reporting Standards. The FASB subsequently issued ASU 2015-14, ASU 2016-08, ASU 2016-10 and ASU 2016-12, which deferred the effective date of ASU 2014-09 and provided additional implementation guidance. These ASUs are effective for fiscal years, and interim periods within those years, beginning after December 31, 2017. The standards permit 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 is currently evaluating the impact of adopting these standards on its consolidated financial statements, as well as the transition method to be applied.

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2. OIL AND GAS PROPERTIES

Net capitalized costs related to the Company's oil and gas producing activities at September 30, 2016 and December 31, 2015 are as follows (in thousands):

	September 30, 2016	December 31, 2015
Proved leasehold costs	$ 3,276,456	$ 3,206,237
Unproved leasehold costs	482,042	689,754
Costs of completed wells and facilities	9,436,415	9,503,020
Wells and facilities in progress	526,251	505,514
Total oil and gas properties, successful efforts method	13,721,164	13,904,525
Accumulated depletion	(4,138,786)	(3,279,156)
Oil and gas properties, net	$ 9,582,378	$ 10,625,369

3. ACQUISITIONS AND DIVESTITURES

2016 Acquisitions and Divestitures

In July 2016, the Company completed the sale of its interest in its enhanced oil recovery project in the North Ward Estes field in Ward and Winkler counties of Texas, including Whiting's interest in certain CO2 properties in the McElmo Dome field in Colorado, two contracts for the supply and delivery of CO2, and certain other related assets and liabilities (the "North Ward Estes Properties") for a cash purchase price of $300 million (before closing adjustments). The sale was effective July 1, 2016 and resulted in a pre-tax loss on sale of $188 million. The Company used the net proceeds from the sale to repay a portion of the debt outstanding under its credit agreement.

In addition to the cash purchase price, the buyer has agreed to pay Whiting $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 "Contingent Payment"). The Contingent Payment will be made at the option of the buyer either in cash on July 31, 2018 or in the form of a secured promissory note, accruing interest at 8% per annum with a maturity date of July 29, 2022. The Company has determined that this Contingent Payment is an embedded derivative and has reflected it at fair value in the consolidated financial statements. The fair value of the Contingent Payment as of the closing date of this sale transaction was $39 million. Refer to the "Derivative Financial Instruments" and "Fair Value Measurements" footnotes for more information on this embedded derivative instrument.

There were no significant acquisitions during the nine months ended September 30, 2016.

2015 Acquisitions and Divestitures

In December 2015, the Company completed the sale of a fresh water delivery system, a produced water gathering system and four saltwater disposal wells located in Weld County, Colorado, effective December 16, 2015, for aggregate sales proceeds of $75 million (before closing adjustments).

In June 2015, the Company completed the sale of its interests in certain non-core oil and gas wells, effective June 1, 2015, for aggregate sales proceeds of $150 million (before closing adjustments) resulting in a pre-tax loss on sale of $118 million. The properties included over 2,000 gross wells in 132 fields across 10 states.

In April 2015, the Company completed the sale of its interests in certain non-core oil and gas wells, effective May 1, 2015, for aggregate sales proceeds of $108 million (before closing adjustments) resulting in a pre-tax gain on sale of $29 million. The properties are located in 187 fields across 14 states, and predominately consist of assets that were previously included in the underlying properties of Whiting USA Trust I.

Also during the year ended December 31, 2015, the Company completed several immaterial divestiture transactions for the sale of its interests in certain non-core oil and gas wells and undeveloped acreage, for aggregate sales proceeds of $176 million (before closing adjustments) resulting in a pre-tax gain on sale of $28 million.

There were no significant acquisitions during the year ended December 31, 2015.

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4. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2016 and December 31, 2015 (in thousands):

	September 30, 2016	December 31, 2015
Credit agreement	$ 650,000	$ 800,000
6.5% Senior Subordinated Notes due 2018	275,121	350,000
6.5% Mandatory Convertible Senior Subordinated Notes due 2018	5,975	-
5% Senior Notes due 2019	961,409	1,100,000
5% Mandatory Convertible Senior Notes due 2019	4,651	-
1.25% Convertible Senior Notes due 2020	562,075	1,250,000
1.25% Mandatory Convertible Senior Notes due 2020, Series 1	380,385	-
1.25% Mandatory Convertible Senior Notes due 2020, Series 2	87,404	-
5.75% Senior Notes due 2021	873,609	1,200,000
5.75% Mandatory Convertible Senior Notes due 2021	125,218	-
6.25% Senior Notes due 2023	408,296	750,000
6.25% Mandatory Convertible Senior Notes due 2023	117,333	-
Total principal	4,451,476	5,450,000
Unamortized debt discounts and premiums	(331,338)	(203,082)
Unamortized debt issuance costs on notes	(34,509)	(49,214)
Total long-term debt	$ 4,085,629	$ 5,197,704

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, 2016 had a borrowing base of $2.6 billion, with aggregate commitments of $2.5 billion. Upon closing of the sale of the North Ward Estes Properties on July 27, 2016, the borrowing base was reduced from $2.75 billion to $2.6 billion. In October 2016, the borrowing base under the facility was reduced to $2.5 billion in connection with the November 1, 2016 regular borrowing base redetermination, with no change to the aggregate commitments of $2.5 billion. As of September 30, 2016, the Company had $1.8 billion of available borrowing capacity, which was net of $650 million in borrowings and $11 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. The credit agreement permits the Company to dispose of its ownership interests in certain gas gathering and processing plants located in North Dakota without reducing the borrowing base.

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, 2016, $39 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until December 2019, when the credit agreement expires and all outstanding borrowings are due. Interest under the revolving credit facility 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 revolving credit facility, which are included as a component of interest expense.

At September 30, 2016 and December 31, 2015, the weighted average interest rate on the outstanding principal balance under the credit agreement was 2.9% and 1.9%, respectively.

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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	1.00%	2.00%	0.50%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.50%	2.50%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.75%	2.75%	0.50%
Greater than or equal to 0.90 to 1.0	2.00%	3.00%	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. However, the credit agreement permits the Company and certain of its subsidiaries to issue second lien indebtedness of up to $1.0 billion subject to certain conditions and limitations. 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, 2016, 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, (ii) a total senior secured debt to the last four quarters' EBITDAX ratio of less than 3.0 to 1.0 during the Interim Covenant Period (defined below), and thereafter a total debt to EBITDAX ratio of less than 4.0 to 1.0, and (iii) a ratio of the last four quarters' EBITDAX to consolidated cash interest charges of not less than 2.25 to 1.0 during the Interim Covenant Period. Under the credit agreement, the "Interim Covenant Period" is defined as the period from June 30, 2015 until the earlier of (a) April 1, 2018 or (b) the commencement of an investment-grade debt rating period (as defined in the credit agreement). The Company was in compliance with its covenants under the credit agreement as of September 30, 2016.

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 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% 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" and together with the 2019 Senior Notes and 2021 Senior Notes, the "Senior Notes").

Exchange of Senior Notes and Senior Subordinated Notes for Convertible Notes. On March 23, 2016, the Company completed the exchange of $477 million aggregate principal amount of Senior Notes and 2018 Senior Subordinated

Notes, consisting of (i) $49 million aggregate principal amount of its 2018 Senior Subordinated Notes, (ii) $97 million aggregate principal amount of its 2019 Senior Notes, (iii) $152 million aggregate principal amount of its 2021 Senior Notes, and (iv) $179 million aggregate principal amount of its 2023 Senior Notes, for (i) $49 million aggregate principal amount of new 6.5% Convertible Senior Subordinated Notes due 2018 (the “2018 Convertible Senior Subordinated Notes”), (ii) $97 million aggregate principal amount of new 5% Convertible Senior Notes due 2019 (the “2019 Convertible Senior Notes”), (iii) $152 million aggregate principal amount of new 5.75% Convertible Senior Notes due 2021 (the “2021 Convertible Senior Notes”), and (iv) $179 million aggregate principal amount of new 6.25% Convertible Senior Notes due 2023 (the “2023 Convertible Senior Notes” and together with the 2018 Convertible Senior Subordinated Notes, the 2019 Convertible Senior Notes and the 2021 Convertible Senior Notes, the “New Convertible Notes”).

The redemption provisions, covenants, interest payments and maturity terms applicable to each series of New Convertible Notes were substantially identical to those applicable to the corresponding series of Senior Notes and 2018 Senior Subordinated Notes.

This exchange transaction was accounted for as an extinguishment of debt for each portion of the Senior Notes and 2018 Senior Subordinated Notes that was exchanged. As a result, Whiting recognized a $91 million gain on extinguishment of debt, which is net of a $4 million non-cash charge for the acceleration of unamortized debt issuance costs and debt premium on the original notes. Each series of New Convertible Notes was recorded at fair value upon issuance, with the difference between the principal amount of the

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notes and their fair values, totaling $95 million, recorded as a debt discount. The aggregate debt discount of $185 million recorded upon issuance of the New Convertible Notes also included $90 million related to the fair value of the holders' conversion options, which were embedded derivatives that met the criteria to be bifurcated from their host contracts and accounted for separately. Refer to the "Derivative Financial Instruments" and "Fair Value Measurements" footnotes for more information on these embedded derivatives. The debt discount and transaction costs of $8 million attributable to the New Convertible Notes issuance were being amortized to interest expense over the respective terms of the notes using the effective interest method.

The New Convertible Notes were convertible, at the option of the holders, into shares of the Company's common stock at an initial conversion rate of 86.9565 common shares per $1,000 principal amount of the notes (representing an initial conversion price of $11.50 per share) for the 2018 Convertible Senior Subordinated Notes, the 2021 Convertible Senior Notes and the 2023 Convertible Senior Notes and an initial conversion rate of 90.9091 common shares per $1,000 principal amount of the notes (representing an initial conversion price of $11.00 per share) for the 2019 Convertible Senior Notes. Upon exercise of this option, the holder was entitled to receive an early conversion cash payment as well as a cash payment of all accrued and unpaid interest through the conversion date.

During the second quarter of 2016, holders of the New Convertible Notes voluntarily converted all $477 million aggregate principal amount of the New Convertible Notes for approximately 41.8 million shares of the Company's common stock. Upon conversion, the Company paid $46 million in cash consisting of early conversion payments to the holders of the notes, as well as all accrued and unpaid interest on such notes. As a result of the conversions, Whiting recognized a $188 million loss on extinguishment of debt, which consisted of a non-cash charge for the acceleration of unamortized debt issuance costs and debt discount on the notes. As of June 30, 2016, no New Convertible Notes remained outstanding.

Exchange of Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes. On July 1, 2016, the Company completed the exchange of $405 million aggregate principal amount of Senior Notes and 2018 Senior Subordinated Notes for the same aggregate principal amount of new mandatory convertible senior notes and mandatory convertible senior subordinated notes. Refer to "Exchange of Senior Notes, Convertible Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes" below for more information on these exchange transactions and the terms of the new mandatory convertible notes.

Kodiak Senior Notes. In conjunction with the acquisition of Kodiak Oil & Gas Corp. (the "Kodiak Acquisition") in December 2014, Whiting US Holding Company, a wholly-owned subsidiary of the Company, became a co-issuer of Kodiak's $800 million of 8.125% Senior Notes due December 2019 (the "2019 Kodiak Notes"), $350 million of 5.5% Senior Notes due January 2021 (the "2021 Kodiak Notes"), and $400 million of 5.5% Senior Notes due February 2022 (the "2022 Kodiak Notes" and together with the 2019 Kodiak Notes and the 2021 Kodiak Notes, the "Kodiak Notes").

In January 2015, Whiting offered to repurchase at 101% of par all $1,550 million principal amount of Kodiak Notes then outstanding. In March 2015, Whiting paid $760 million to repurchase $2 million aggregate principal amount of the 2019 Kodiak Notes, $346 million aggregate principal amount of the 2021 Kodiak Notes and $399 million aggregate principal amount of the 2022 Kodiak Notes, which payment consisted of the 101% redemption price and all accrued and unpaid interest on such notes. In May 2015, Whiting paid an additional $5 million to repurchase the remaining $4 million aggregate principal amount of the 2021 Kodiak Notes and $1 million aggregate principal amount of the 2022 Kodiak Notes, which payment consisted of the 101% redemption price and all accrued and unpaid interest on such notes. In December 2015, Whiting paid $834 million to repurchase the remaining $798 million aggregate principal amount of the 2019 Kodiak Notes, which payment consisted of the 104.063% redemption price and all accrued and unpaid interest on such notes. As a result of the repurchases, Whiting recognized an $18 million loss on extinguishment of debt, which consisted of a $40 million cash charge related to the redemption premium on the Kodiak Notes, partially offset by a $22 million non-cash credit related to the acceleration of unamortized debt premiums on such notes. As of December 31, 2015, no Kodiak 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. On June 29, 2016, the Company exchanged $129 million aggregate principal amount of its 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes, and on July 1, 2016, the Company exchanged $559 million aggregate principal amount of its 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Refer to “Exchange of Senior Notes, Convertible Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes” below for more information on these exchange transactions and the terms of the new mandatory convertible notes.

For the remaining $562 million aggregate principal amount of 2020 Convertible Senior Notes, 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

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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 an initial conversion rate of 25.6410 shares of Whiting’s common stock per $1,000 principal amount of the notes, which is equivalent to an initial conversion price of approximately $39.00. 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, 2016, 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 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 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 consist of the following at September 30, 2016 and December 31, 2015 (in thousands):

	September 30, 2016	December 31, 2015
Liability component:		
Principal	$ 562,075	$ 1,250,000
Less: unamortized note discount	(77,680)	(205,572)

Less: unamortized debt issuance costs	(6,436)	(17,277)
Net carrying value	$ 477,959	$ 1,027,151
Equity component (1)	$ 136,522	$ 237,500

(1) Recorded in additional paid-in capital, net of $5 million of issuance costs and $50 million of deferred taxes as of September 30, 2016 and $5 million of issuance costs and $88 million of deferred taxes as of December 31, 2015.

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, 2016 and 2015 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Interest expense on 2020 Convertible Senior Notes	$ 6,745	$ 14,395	$ 36,068	$ 29,276

Mandatory Convertible Notes

Exchange of Senior Notes, Convertible Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes. On June 29, 2016, the Company completed the exchange of $129 million aggregate principal amount of its 2020 Convertible Senior Notes for the same aggregate principal amount of new 1.25% Mandatory Convertible Senior Notes due 2020, Series 2 (the “2020 Mandatory

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Convertible Notes, Series 2”). On July 1, 2016, the Company completed the exchange of $964 million aggregate principal amount of Senior Notes, 2020 Convertible Senior Notes and 2018 Senior Subordinated Notes, consisting of (i) $26 million aggregate principal amount of its 2018 Senior Subordinated Notes, (ii) $42 million aggregate principal amount of its 2019 Senior Notes, (iii) $559 million aggregate principal amount of its 2020 Convertible Senior Notes, (iv) $174 million aggregate principal amount of its 2021 Senior Notes, and (v) $163 million aggregate principal amount of its 2023 Senior Notes, for (i) $26 million aggregate principal amount of new 6.5% Mandatory Convertible Senior Subordinated Notes due 2018 (the “2018 Mandatory Convertible Notes”), (ii) $42 million aggregate principal amount of new 5% Mandatory Convertible Senior Notes due 2019 (the “2019 Mandatory Convertible Notes”), (iii) $559 million aggregate principal amount of new 1.25% Mandatory Convertible Senior Notes due 2020, Series 1 (the “2020 Mandatory Convertible Notes, Series 1”, and together with the 2020 Mandatory Convertible Notes, Series 2, the “2020 Mandatory Convertible Notes”), (iv) $174 million aggregate principal amount of new 5.75% Mandatory Convertible Senior Notes due 2021 (the “2021 Mandatory Convertible Notes”), and (v) $163 million aggregate principal amount of new 6.25% Mandatory Convertible Senior Notes due 2023 (the “2023 Mandatory Convertible Notes” and, together with the 2018 Mandatory Convertible Notes, the 2019 Mandatory Convertible Notes, the 2020 Mandatory Convertible Notes and the 2021 Mandatory Convertible Notes, the “Mandatory Convertible Notes”).

The redemption provisions, covenants, interest payments and maturity terms applicable to each series of Mandatory Convertible Notes are substantially identical to those applicable to the corresponding series of Senior Notes, 2020 Convertible Senior Notes and 2018 Senior Subordinated Notes except that the 2020 Mandatory Convertible Notes will mature on June 5, 2020 unless earlier converted in accordance with their terms.

These transactions were accounted for as extinguishments of debt for the portions of Senior Notes, 2020 Convertible Senior Notes and 2018 Senior Subordinated Notes that were exchanged. As a result, Whiting recognized a $57 million gain on extinguishment of debt, which was net of a $113 million charge for the non-cash write-off of unamortized debt issuance costs, debt discounts and debt premium on the original notes. In addition, Whiting recorded a $63 million reduction to the equity component of the 2020 Convertible Senior Notes, which is net of deferred taxes. The Mandatory Convertible Notes were recorded at fair value upon issuance with the difference between the principal amount of the notes and their fair values, totaling $69 million, recorded as a debt discount. The Mandatory Convertible Notes contain contingent beneficial conversion features, the intrinsic value of which was recognized in additional paid-in capital at the time the contingency was resolved, resulting in an additional debt discount of $233 million. The aggregate debt discount of $302 million is being amortized to interest expense over the respective terms of the notes using the effective interest method.

Transaction costs of $14 million attributable to these note issuances 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 respective terms of the notes using the effective interest method.

The July 1, 2016 note exchange transactions triggered an ownership shift as defined under Section 382 of the Internal Revenue Code due to the “deemed share issuance” that resulted from the note exchanges. This triggering event will limit the Company’s usage of certain of its net operating losses and tax credits in the future. Refer to the “Income Taxes” footnote for more information.

The Mandatory Convertible Notes contain mandatory conversion features whereby four percent of the aggregate principal amount of the Mandatory Convertible Notes were converted into shares of the Company’s common stock for each day of the 25 trading day period that commenced on June 23, 2016 (the “Observation Period”) if the daily volume weighted average price (the “Daily VWAP”) (as defined in the indentures governing the Mandatory Convertible Notes) of the Company’s common stock on such day, rounded to four decimal places for the 2020 Mandatory Convertible

Notes and rounded to two decimal places for the 2018 Mandatory Convertible Notes, the 2019 Mandatory Convertible Notes, the 2021 Mandatory Convertible Notes and the 2023 Mandatory Convertible Notes, was above $8.75 (the "Threshold Price"). Upon conversion, the common stock issue price per share is equal to the higher of (i) the Daily VWAP for the Company's common stock for such trading day multiplied by one plus zero for the 2018 Mandatory Convertible Notes, one plus 0.5% for the 2019 Mandatory Convertible Notes, one plus 8.0% for the 2020 Mandatory Convertible Notes, one plus 2.5% for the 2021 Mandatory Convertible Notes and one plus 3.5% for the 2023 Mandatory Convertible Notes or (ii) $8.75 for the 2018 Mandatory Convertible Notes (equivalent to 114.29 common shares per $1,000 principal amount of the notes), $8.79 for the 2019 Mandatory Convertible Notes (equivalent to 113.72 common shares per $1,000 principal amount of the notes), $9.45 for the 2020 Mandatory Convertible Notes (equivalent to 105.82 common shares per $1,000 principal amount of the notes), $8.97 for the 2021 Mandatory Convertible Notes (equivalent to 111.50 common shares per $1,000 principal amount of the notes) and $9.06 for the 2023 Mandatory Convertible Notes (equivalent to 110.42 common shares per $1,000 principal amount of the notes) (the "Minimum Conversion Prices").

After the Observation Period, the Company has the right to mandatorily convert any remaining Mandatory Convertible Notes if the Daily VWAP of the Company's common stock exceeds $8.75 for at least 20 trading days during a 30 consecutive trading day period and holders have the right to convert the Mandatory Convertible Notes at any time. The conversion price after the Observation Period will be the Minimum Conversion Price for each applicable series of Mandatory Convertible Notes. As of September 30, 2016, none of the conditions allowing the Company to convert the remaining Mandatory Convertible Notes had been met, and no holders of the Mandatory Convertible Notes had voluntarily converted any such notes.

Conversion of Mandatory Convertible Notes to Common Stock. During the Observation Period, the Daily VWAP of the Company's common stock was above the Threshold Price (i) for 7 of the 25 trading days for the 2018 Mandatory Convertible Notes, the 2019 Mandatory Convertible Notes, the 2021 Mandatory Convertible Notes and the 2023 Mandatory Convertible Notes and (ii) for 8 of the 25 trading days for the 2020 Mandatory Convertible Notes. As a result, $333 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 33.2 million shares of the Company's common stock, and the Company paid $3 million in cash consisting of all accrued and unpaid interest on such notes. As a result of the conversions, Whiting recognized a $3 million gain on extinguishment of debt, which was net of a non-cash charge for the acceleration of unamortized debt issuance costs and debt discount on the notes.

Induced Exchange of Mandatory Convertible Notes. On August 12, 2016, the Company completed the exchange of (i) $13 million aggregate principal amount of the 2018 Mandatory Convertible Notes which had a conversion price of $8.75 per share (equivalent to 114.29 common shares per $1,000 principal amount of the notes) for shares of the Company's common stock at an issuance price of $7.77 per share (equivalent to 128.69 common shares per $1,000 principal amount of the notes) and (ii) $25 million aggregate principal amount of the 2019 Mandatory Convertible Notes which had a conversion price of $8.79 per share (equivalent to 113.72 common shares per $1,000 principal amount of the notes) for shares of the Company's common stock at an issuance price of $7.80 per share (equivalent to 128.17 shares per $1,000 principal amount of the notes). Upon acceptance of this inducement offer by the holders of the notes, such notes were immediately cancelled in exchange for approximately 4.9 million shares of the Company's common stock and the Company paid $1 million in cash consisting of all accrued and unpaid interest on such notes. As a result of the exchanges, Whiting recognized (i) $4 million of debt inducement expense related to the fair value of the incremental shares issued in the inducement offer over the original conversion terms of the notes, which expense is included in (gain) loss on extinguishment of debt in the consolidated statements of operations, and (ii) a $14 million non-cash charge for the acceleration of unamortized debt discount on the notes, which is included in interest expense in the consolidated statements of operations.

Security and Guarantees

The Senior Notes, the 2020 Convertible Senior Notes, the 2019 Mandatory Convertible Notes, the 2020 Mandatory Convertible Notes, the 2021 Mandatory Convertible Notes and the 2023 Mandatory Convertible Notes (collectively, the "Whiting 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 2018 Senior Subordinated Notes and the 2018 Mandatory Convertible Notes are also unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of the Whiting Senior Notes and borrowings under Whiting Oil and Gas' credit agreement.

The Company's obligations under the Whiting Senior Notes, the 2018 Senior Subordinated Notes and the 2018 Mandatory Convertible 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 Company follows FASB ASC Topic 410, Asset Retirement and Environmental Obligations, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The current portions at September 30, 2016 and December 31, 2015 were $7 million and $6 million, respectively, and have been included in accrued liabilities and other. Revisions to the liability typically occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells. The following table provides a reconciliation of the Company's asset retirement obligations for the nine months ended September 30, 2016 (in thousands):

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Asset retirement obligation at January 1, 2016	$ 161,908
Additional liability incurred	1,768
Revisions to estimated cash flows	5,412
Accretion expense	10,512
Obligations on sold properties	(2,102)
Liabilities settled	(5,841)
Asset retirement obligation at September 30, 2016	$ 171,657

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. Whiting follows FASB ASC Topic 815, Derivatives and Hedging, to account for its derivative financial instruments.

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 enters into derivative contracts such as costless collars, swaps and crude oil sales and delivery contracts to achieve a more predictable cash flow by reducing its exposure to commodity price volatility. Commodity derivative contracts are thereby used to ensure adequate cash flow to fund the Company's capital programs and to manage returns on drilling programs and acquisitions. The Company does not enter into derivative contracts for speculative or trading purposes.

Crude Oil Costless Collars. Costless collars are designed to establish floor and ceiling prices on 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 derivatives entered into to hedge forecasted crude oil production revenues as of October 1, 2016.

Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Three-way collars (1)	Oct - Dec 2016	4,200,000	$43.75 - $53.75 - $74.40
	Jan - Dec 2017	11,400,000	$34.21 - $44.47 - $60.06
Collars	Oct - Dec 2016	750,000	$51.00 - $63.48
	Jan - Dec 2017	3,000,000	$53.00 - $70.44
	Total	19,350,000	

(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. The Company has 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 has committed to deliver certain fixed volumes of crude oil through 2020. The Company determined that 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, and accordingly, that 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 September 30, 2016, the estimated fair value of this derivative contract was a liability of $10 million.

Embedded Derivatives—In March 2016, the Company issued convertible notes that contained debtholder conversion options which the Company determined were not clearly and closely related to the debt host contracts, and the Company therefore bifurcated these embedded features and reflected them at fair value in the consolidated financial statements. During the second quarter of 2016, the entire aggregate principal amount of these notes was converted into shares of the Company's common stock, and the fair value of these embedded derivatives as of September 30, 2016 was therefore zero.

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In July 2016, the Company entered into a purchase and sale agreement with the buyer of its North Ward Estes Properties, whereby the buyer has 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 has determined that this NYMEX-linked Contingent Payment is 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. As of September 30, 2016, the estimated fair value of this embedded derivative was an asset of $47 million.

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, 2016 and 2015 (in thousands):

		(Gain) Loss Recognized in Income Nine Months Ended September 30,	
Not Designated as ASC 815 Hedges	Statement of Operations Classification	2016	2015
Commodity contracts	Derivative gain, net	$ 27,663	$ (115,215)
Embedded derivatives	Derivative gain, net	(56,095)	-
Total		$ (28,432)	$ (115,215)

		(Gain) Loss Recognized in Income Three Months Ended September 30,	
Not Designated as ASC 815 Hedges	Statement of Operations Classification	2016	2015
Commodity contracts	Derivative gain, net	$ (22,302)	$ (207,783)
Embedded derivatives	Derivative gain, net	(8,130)	-
Total		$ (30,432)	$ (207,783)

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):

Not Designated as ASC 815 Hedges	Balance Sheet Classification	September 30, 2016 (1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts - current	Derivative assets	$ 64,867	$ (30,813)	$ 34,054
Commodity contracts - non-current	Other long-term assets	16,069	(15,126)	943
Embedded derivatives - non-current	Other long-term assets	47,370	-	47,370
Total derivative assets		$ 128,306	$ (45,939)	$ 82,367
Derivative liabilities:				
Commodity contracts - current	Accrued liabilities and other	$ 33,787	$ (30,813)	$ 2,974
Commodity contracts - non-current	Other long-term liabilities	22,693	(15,126)	7,567
Total derivative liabilities		$ 56,480	$ (45,939)	$ 10,541

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Not Designated as ASC 815 Hedges	Balance Sheet Classification	December 31, 2015 (1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts - current	Derivative assets	$ 258,778	$ (100,049)	$ 158,729
Commodity contracts - non-current	Other long-term assets	31,415	(3,465)	27,950
Total derivative assets		$ 290,193	$ (103,514)	$ 186,679
Derivative liabilities:				
Commodity contracts - current	Accrued liabilities and other	$ 101,214	$ (100,049)	$ 1,165
Commodity contracts - non-current	Other long-term liabilities	6,327	(3,465)	2,862
Total derivative liabilities		$ 107,541	$ (103,514)	$ 4,027

(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.

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 and 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.

The Company's senior notes and senior subordinated notes are recorded at cost, and the Company's convertible senior notes and convertible senior subordinated 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, 2016 and December 31, 2015 (in thousands):

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	September 30, 2016		December 31, 2015	
	Fair Value	Carrying Value (3)	Fair Value	Carrying Value (3)
6.5% Senior Subordinated Notes due 2018 (1)	$ 269,619	$ 273,290	$ 265,125	$ 346,876
6.5% Mandatory Convertible Senior Subordinated Notes due 2018 (2)	6,230	3,768	-	-
5% Senior Notes due 2019 (1)	918,146	956,098	830,500	1,092,219
5% Mandatory Convertible Senior Notes due 2019 (2)	4,817	2,904	-	-
1.25% Convertible Senior Notes due 2020 (1)	460,154	477,959	850,000	1,027,151
1.25% Mandatory Convertible Senior Notes due 2020, Series 1 (2)	357,460	243,127	-	-
1.25% Mandatory Convertible Senior Notes due 2020, Series 2 (2)	82,136	56,648	-	-
5.75% Senior Notes due 2021 (1)	812,456	868,261	870,000	1,191,861
5.75% Mandatory Convertible Senior Notes due 2021 (2)	125,327	77,698	-	-
6.25% Senior Notes due 2023 (1)	374,612	403,103	543,750	739,597
6.25% Mandatory Convertible Senior Notes due 2023 (2)	116,807	72,773	-	-
Total	$ 3,527,764	$ 3,435,629	$ 3,359,375	$ 4,397,704

(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) Fair value is determined using a binomial lattice model which considers various inputs including (i) Whiting's common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) recovery rates in the event of default, (iv) default intensity, and (v) volatility of Whiting's common stock. The expected volatility and default intensity used in the valuation are unobservable in the marketplace and significant to the valuation methodology, and such fair value is therefore designated as Level 3 within the valuation hierarchy.
(3) Carrying values are presented net of unamortized debt issuance costs and debt discounts or premiums, including discounts related to the beneficial conversion features associated with the Mandatory Convertible Notes.

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 assets and liabilities measured at fair value on a recurring basis as of September 30, 2016 and December 31, 2015, 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, 2016
Financial Assets				
Commodity derivatives – current	$ -	$ 34,054	$ -	$ 34,054
Commodity derivatives – non-current	-	943	-	943
Embedded derivatives – non-current	-	47,370	-	47,370

Total financial assets	$ -	$ 82,367	$ -	$ 82,367
Financial Liabilities				
Commodity derivatives – current	$ -	$ 29	$ 2,945	$ 2,974
Commodity derivatives – non-current	-	916	6,651	7,567
Total financial liabilities	$ -	$ 945	$ 9,596	$ 10,541

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	Level 1	Level 2	Level 3	Total Fair Value December 31, 2015
Financial Assets				
Commodity derivatives – current	$ -	$ 158,729	$ -	$ 158,729
Commodity derivatives – non-current	-	27,950	-	27,950
Total financial assets	$ -	$ 186,679	$ -	$ 186,679
Financial Liabilities				
Commodity derivatives – current	$ -	$ -	$ 1,165	$ 1,165
Commodity derivatives – non-current	-	-	2,862	2,862
Total financial liabilities	$ -	$ -	$ 4,027	$ 4,027

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 for crude oil. The Company's costless collars are valued based on an income approach. The option model considers 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 has a long-term crude oil sales and delivery contract, whereby it has committed to deliver certain fixed volumes of crude oil through 2020. Whiting has determined that the contract does not meet the "normal purchase normal sale" exclusion, and has therefore reflected this contract at fair value in its consolidated financial statements. This commodity derivative was valued based on an income approach which considers various assumptions, including quoted forward 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 include 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.

Embedded Derivatives. The Company had embedded derivatives related to its convertible notes that were issued in March 2016. The notes contained debtholder conversion options which the Company determined were not clearly and closely related to the debt host contracts and the Company therefore bifurcated these embedded features and reflected them at fair value in the consolidated financial statements. Prior to their settlements, the fair values of these embedded derivatives were determined using a binomial lattice model which considered various inputs including (i) Whiting's common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) recovery rates in the event of default, (iv) default intensity, and (v) volatility of Whiting's common stock. The expected volatility and default intensity used in the valuation were unobservable in the marketplace and significant to the valuation methodology, and the embedded derivatives' fair value was therefore designated as Level 3 in the valuation hierarchy. During the second quarter of 2016, the entire aggregate principal amount of these convertible notes was converted into shares of the Company's common stock, and these embedded derivatives were thereby settled in their entirety as of June 30, 2016.

The Company has an embedded derivative related to its purchase and sale agreement with the buyer of the North Ward Estes Properties. The agreement includes a Contingent Payment linked to NYMEX crude oil prices which the Company has determined is 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. 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 are observable in the marketplace throughout the full term of the financial instrument, 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 rate used in the fair value of this instrument includes a measure of the counterparty's nonperformance risk.

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

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The following table presents a reconciliation of changes in the fair value of financial assets or liabilities designated as Level 3 in the valuation hierarchy for the three and nine months ended September 30, 2016 and 2015 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Fair value asset (liability), beginning of period	$ (9,884)	$ (7,541)	$ (4,027)	$ 53,530
Recognition of embedded derivatives associated with convertible note issuances	-	-	(89,884)	-
Unrealized gains (losses) on commodity derivative contracts included in earnings (1)	288	(3,228)	(5,569)	(64,299)
Unrealized gains on embedded derivatives included in earnings (1)	-	-	47,965	-
Settlement of embedded derivatives upon conversion of convertible notes	-	-	41,919	-
Transfers into (out of) Level 3	-	-	-	-
Fair value liability, end of period	$ (9,596)	$ (10,769)	$ (9,596)	$ (10,769)

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

Quantitative Information About Level 3 Fair Value Measurements. The significant unobservable inputs used in the fair value measurement of the Company’s commodity derivative instrument designated as Level 3 are as follows:

Derivative Instrument	Valuation Technique	Unobservable Input	Amount
Commodity derivative contract	Income approach	Market differential for crude oil	$4.91 per Bbl

Sensitivity to Changes In Significant Unobservable Inputs. As presented above, the significant unobservable inputs used in the fair value measurement of Whiting’s commodity derivative contract are the market differentials for crude oil over the term of the contract. Significant increases or decreases in these unobservable inputs in isolation would result in a significantly higher or lower, respectively, fair value liability measurement.

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 and goodwill. 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 or goodwill during the 2016 reporting periods presented. The following table presents information about the Company’s non-financial assets measured at fair value on a non-recurring basis as of September 30, 2015, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Impairment Loss

	Net Carrying Value as of September 30, 2015	Fair Value Measurements Using Level 1	Level 2	Level 3	(Before Tax) Three and Nine Months Ended September 30, 2015
Proved property (1)	$ 531,775	$ -	$ -	$ 531,775	$ 1,602,226
Goodwill (2)	-	-	-	-	869,713
Total non-recurring assets at fair value	$ 531,775	$ -	$ -	$ 531,775	$ 2,471,939

(1) During the third quarter of 2015, proved oil and gas properties with a previous carrying amount of $2.1 billion were written down to their fair value as of September 30, 2015 of $531 million, resulting in a non-cash impairment charge of $1.5 billion which was recorded within exploration and impairment expense. The impaired properties consisted of the Company's North Ward Estes field in Texas and other non-core proved oil and gas properties primarily in Texas, Wyoming, North Dakota and Colorado that were not being developed due to depressed oil and gas prices. Also during the third quarter of 2015, proved CO2 properties at the Bravo Dome field in New Mexico and the McElmo Dome field in Colorado with a previous carrying amount of $63 million were written down to their fair value as of September 30, 2015 of $1 million, resulting in a non-cash impairment charge of $62 million which was also recorded within exploration and impairment expense.

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(2) During the third quarter of 2015, goodwill related to the acquisition of Kodiak with a previous carrying amount of $870 million was written down to its fair value of zero, resulting in a non-cash impairment charge of $870 million which was recorded as a separate line in the consolidated statements of operations.

The following methods and assumptions were used to estimate the fair values of the non-financial assets in the table above:

Proved Property Impairments. The Company tests proved property for impairment whenever events or changes in circumstances indicate that the fair value of these assets may be reduced below their carrying value. As a result of the significant decrease in the forward price curves for crude oil and natural gas during the third quarter of 2015, and the associated decline in oil and gas reserves over that same period, the Company performed a proved property impairment test as of September 30, 2015. The fair value was ascribed using income approach analyses based on the net discounted future cash flows from the producing property and a market approach analysis, which approaches have been probability-weighted. The discounted cash flows were based on management's expectations for the future. Unobservable inputs included estimates of future oil and gas or CO2 production, as the case may be, from the Company's reserve reports, commodity prices based on sales contract terms or forward price curves (adjusted for basis differentials), operating and development costs, and a discount rate based on the Company's weighted-average cost of capital (all of which were designated as Level 3 inputs within the fair value hierarchy). The impairment test indicated that a proved property impairment had occurred, and the Company therefore recorded a non-cash impairment charge to reduce the carrying value of the impaired property to its fair value at the measurement date.

Goodwill Impairment. The Company tested goodwill for impairment annually in the second quarter or whenever events or changes in circumstances indicated that the fair value of its reporting unit may have been reduced below its carrying value. The Company performed its annual goodwill impairment test as of June 30, 2015, and determined that no impairment had occurred. However, as a result of a sustained decrease in the price of Whiting's common stock during the third quarter of 2015 caused by a significant decline in crude oil and natural gas prices over that same period, the Company performed another goodwill impairment test as of September 30, 2015. The fair value of the Company's reporting unit was ascribed using an income approach analysis based on the Company's net discounted future cash flows and a market approach analysis. The discounted cash flows were based on management's expectations for the future. Unobservable inputs included estimates of future oil and gas production from the Company's reserve reports, commodity prices based on sales contract terms or forward price curves (adjusted for basis differentials), operating and development costs, and a discount rate based on the Company's weighted-average cost of capital (all of which were designated as Level 3 inputs within the fair value hierarchy). The impairment test performed by the Company indicated that the fair value of its reporting unit was less than its carrying amount, and further that there was no remaining implied fair value attributable to goodwill. Based on these results, the Company recorded a non-cash impairment charge to reduce the carrying value of goodwill to zero.

8. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

Common Stock—In May 2016, Whiting's shareholders approved an amendment to the Company's Restated Certificate of Incorporation to increase the number of authorized shares of common stock from 300,000,000 to 600,000,000 shares.

Common Stock Offering. In March 2015, the Company completed a public offering of its common stock, selling 35,000,000 shares of common stock at a price of $30.00 per share and providing net proceeds of approximately $1.0 billion after underwriter's fees. In addition, the Company granted the underwriter a 30-day option to purchase up to an additional 5,250,000 shares of common stock. On April 1, 2015, the underwriter exercised its right to purchase an additional 2,000,000 shares of common stock, providing additional net proceeds of $61 million.

Equity Incentive Plan—At the Company's 2013 Annual Meeting held on May 7, 2013, shareholders approved the Whiting Petroleum Corporation 2013 Equity Incentive Plan (the "2013 Equity Plan"), which replaced the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the "2003 Equity Plan") and included the authority to issue 5,300,000 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 after May 7, 2013 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. On December 8, 2014, the Company increased the number of shares issuable under the 2013 Equity Plan by 978,161 shares to accommodate for the conversion of Kodiak's outstanding equity awards to Whiting equity awards upon closing of the Kodiak Acquisition. Any shares netted or forfeited under this increased availability will be cancelled and will not be available for future issuance under the 2013 Equity Plan. At the Company's 2016 Annual Meeting held on May 17, 2016, shareholders approved an amendment and restatement of the 2013 Equity Plan which increased the total number of shares issuable under the plan by 5,500,000 and revised certain award limits for employees and non-employee directors. Under the amended and restated 2013 Equity Plan, no employee or officer participant may be granted options for more than 900,000 shares of common stock, stock appreciation rights relating to more than 900,000 shares of common stock, or more than 600,000 shares of restricted stock during any calendar year. In addition, no non-employee director participant may be granted options for more than 100,000 shares of common stock, stock appreciation rights relating to more than 100,000 shares of common stock, or more than 100,000 shares of restricted stock during any calendar year. As of September 30, 2016, 6,222,650 shares of common stock remained available for grant under the amended 2013 Equity Plan.

Noncontrolling Interest—The Company's noncontrolling interest represents an unrelated third party's 25% ownership interest in Sustainable Water Resources, LLC. The table below summarizes the activity for the equity attributable to the noncontrolling interest (in thousands):

	Nine Months Ended September 30,	
	2016	2015
Balance at beginning of period	$ 7,984	$ 8,070
Net loss	(18)	(48)
Balance at end of period	$ 7,966	$ 8,022

9. 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, 2016 and 2015 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% to pre-tax income primarily because of state income taxes and estimated permanent differences. In addition, during the third quarter of 2016, the Company's note exchange transactions triggered an ownership shift as defined under Section 382 of the Internal Revenue Code due to the "deemed share issuance" that resulted from the note exchanges. This triggering event will limit the Company's usage of certain of its net operating losses and tax credits in the future. Accordingly, the Company recognized a write-down of deferred tax assets totaling $315 million and recorded a valuation allowance on its net operating losses of $139 million during the third quarter of 2016, resulting in a total non-cash charge of $454 million. The Company expects to record an additional valuation allowance of approximately $14 million in the fourth quarter of 2016, bringing the total non-cash charge related to the Section 382 limitation to approximately $468 million.

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 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.

10. EARNINGS PER SHARE

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Basic Loss Per Share				
Numerator:				
Net loss available to common shareholders, basic	$ (693,052)	$ (1,865,108)	$ (1,165,841)	$ (2,120,493)
Denominator:				
Weighted average shares outstanding, basic	280,418	204,143	237,100	192,549
Diluted Loss Per Share				
Numerator:				
Adjusted net loss available to common shareholders, diluted	$ (693,052)	$ (1,865,108)	$ (1,165,841)	$ (2,120,493)
Denominator:				
Weighted average shares outstanding, diluted	280,418	204,143	237,100	192,549
Loss per common share, basic	$ (2.47)	$ (9.14)	$ (4.92)	$ (11.01)
Loss per common share, diluted	$ (2.47)	$ (9.14)	$ (4.92)	$ (11.01)

During the three months ended September 30, 2016, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of (i) 81,549,680 shares issuable upon conversion of the Mandatory Convertible Notes, (ii) 1,240,145 shares of service-based restricted stock and (iii) 4,448 stock options. In addition, the diluted earnings per share calculation for the three months ended September 30, 2016 excludes the dilutive effect of 2,090,383 common shares for stock options that were out-of-the-money and 897,005 shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2016.

During the three months ended September 30, 2015, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of 94,513 shares of service-based restricted stock and 59,320 stock options. In addition, the diluted earnings per share calculation for the three months ended September 30, 2015 excludes (i) the anti-dilutive effect of 359,270 incremental shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2015 and (ii) the dilutive effect of 712,778 common shares for stock options that were out-of-the-money.

During the nine months ended September 30, 2016, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of (i) 27,478,601 shares issuable upon conversion of the Mandatory Convertible Notes, (ii) 1,351,434 shares of service-based restricted stock and (iii) 4,573 stock options. In addition, the diluted earnings per share calculation for the nine months ended September 30, 2016 excludes the dilutive effect of 2,065,797 common shares for stock options that were out-of-the-money and 523,351 shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2016.

During the nine months ended September 30, 2015, the Company had a net loss and therefore the diluted earnings per share calculation for that period excludes the anti-dilutive effect of 442,713 shares of service-based restricted stock and 94,434 stock options. In addition, the diluted earnings per share calculation for the nine months ended September 30, 2015 excludes (i) the anti-dilutive effect of 644,233 incremental shares of restricted stock that did not meet its market-based vesting criteria as of September 30, 2015 and (ii) the dilutive effect of 405,065 common shares for stock options that were out-of-the-money.

As discussed in the “Long-Term Debt” footnote, the Company has the option to settle the 2020 Convertible Senior Notes with cash, shares of common stock or any combination thereof upon conversion. Based on the initial conversion price, the entire outstanding principal amount of the 2020 Convertible Senior Notes as of September 30, 2016 would be convertible into approximately 21.9 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, 2016, the conversion value did not exceed the principal amount of the notes, and accordingly, there was no impact to diluted earnings per share or the related disclosures for those periods.

11. COMMITMENTS AND CONTINGENCIES

During the second quarter of 2016, the Company terminated two ship-or-pay agreements with the same counterparty that expired in 2026, and incurred termination penalties totaling $1 million. Under the original agreements, the Company had committed to transport a minimum daily volume of crude oil or water, as the case may be, via certain pipelines or else pay for any deficiencies at prices stipulated in the contracts. The termination of these agreements reduced the Company’s future commitments under this agreement by approximately $67 million as of June 30, 2016.

As discussed in the "Acquisitions and Divestitures" footnote, the Company sold its interest in the North Ward Estes field in Texas on July 27, 2016. In conjunction with this sale, the Company transferred to the buyer of the properties (i) a take-or-pay purchase agreement that expires in 2017 to buy certain volumes of CO_2 for use in the North Ward Estes EOR project, and (ii) a ship-or-pay agreement that expires in 2017 to transport a minimum daily volume of CO_2 via certain pipelines. The transfer of these agreements reduced the Company's future commitments under these contracts by approximately $51 million as of the July 1, 2016 effective date of the sale.

12. SUBSEQUENT EVENTS

In October 2016, the borrowing base under Whiting Oil and Gas' credit agreement was reduced from $2.6 billion to $2.5 billion in connection with the November 1, 2016 regular borrowing base redetermination, with no change to the aggregate commitments of $2.5 billion. All other terms of the credit agreement remain unchanged.

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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 (formerly Kodiak Oil & Gas Corp., "Kodiak"), Whiting Resources Corporation (formerly Kodiak Oil & Gas (USA) Inc.) 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. Since 2006, we have increased our focus on organic drilling activity and on the development of previously acquired properties, specifically on projects that we believe provide the opportunity for repeatable success and production growth, while selectively pursuing acquisitions that complement our existing core properties. As a result of sustained lower crude oil prices in 2015 and the first nine months of 2016, we have significantly reduced our level of capital spending to more closely align with our cash flows generated from operations, and have focused our drilling activity on projects that provide the highest rate of return. 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 sale of our North Ward Estes properties in July 2016 discussed below under "Acquisition and Divestiture Highlights" and the other asset sales in 2015 discussed in the "Acquisitions and Divestitures" footnote in the notes to 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 as well as economic, political and regulatory developments and competition from other sources of energy, as well as other items discussed under the caption "Risk Factors" in this Quarterly Report on Form 10-Q and in Item 1A of our Annual Report on Form 10-K for the period ended December 31, 2015. 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 2014:

	2014				2015				2016		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3
Crude oil	$ 98.62	$ 102.98	$ 97.21	$ 73.12	$ 48.57	$ 57.96	$ 46.44	$ 42.17	$ 33.51	$ 45.60	$ 44.94
Natural gas	$ 4.93	$ 4.68	$ 4.07	$ 4.04	$ 2.99	$ 2.61	$ 2.74	$ 2.17	$ 2.06	$ 1.98	$ 2.93

Oil prices have fallen significantly since reaching highs of over $105.00 per Bbl in June 2014, dropping below $27.00 per Bbl in February 2016. Natural gas prices have also declined from over $4.80 per Mcf in April 2014 to below $1.70 per Mcf in March 2016. Although oil and natural gas prices have begun to recover from the lows experienced during the first quarter of 2016, forecasted prices for both oil and gas remain low. Lower oil, NGL and natural gas prices may not only decrease our revenues, 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 continue to 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 have reduced, and may further reduce, the amount of our borrowing base under our credit agreement (such as the reduction discussed below under "Financing Highlights"), which is determined at the discretion of the 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.

2016 Highlights and Future Considerations

Operational Highlights

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 105.6 MBOE/d for the third quarter of 2016, which represents an 8% decrease from 114.4 MBOE/d in the second quarter of 2016. In April and July 2016, we entered into two separate wellbore participation agreements related to the wells that we intend to drill in the Williston Basin during 2016, which will allow us to continue completion activity in this area. As of September 30, 2016, we had three rigs active in the Williston Basin. In October 2016, we moved an additional rig from our Redtail field to this area. Across our acreage in the Williston Basin, we have implemented new completion designs which utilize cemented liners, plug-and-perf technology, significantly higher sand volumes, new diversion technology and both hybrid and slickwater fracture stimulation methods, which have resulted in improved initial production rates.

In order to process the produced gas stream from our wells in the Sanish field, we constructed the Robinson Lake gas plant. The plant has a current processing capacity of 130 MMcf/d and fractionation equipment that allows us to convert NGLs into propane and butane, which end products can then be sold locally for higher realized prices. As of September 30, 2016, the plant was processing over 113 MMcf/d.

We also hold a 50% ownership interest in a gas processing plant, gathering systems and related facilities located south of Belfield, North Dakota, which primarily processes production from our Pronghorn field. There is currently inlet compression in place to process 35 MMcf/d, and as of September 30, 2016, the plant was processing over 20 MMcf/d.

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. In the third quarter of 2016, net production from the Redtail field averaged 10.9 MBOE/d, representing an 8% increase from 10.2 MBOE/d in the second quarter of 2016. We have established production in the Niobrara "A", "B" and "C" zones and the Codell/Fort Hays formations. Our development plan at Redtail currently includes drilling up to eight wells per spacing unit in the Niobrara "A", "B" and "C" zones and up to four wells per spacing unit in the Codell/Fort Hays formations.   Additionally, the Codell/Fort Hays formation is prospective throughout our acreage in the Redtail field, and we are currently evaluating that formation. We have implemented a new wellbore configuration in this area, which significantly reduces drilling times. As of September 30, 2016, we had two drilling rigs operating in the DJ Basin. In October 2016, we moved one of the rigs from this area to the Williston Basin. We suspended completion operations in this area beginning in the second quarter of 2016; however, we plan to resume completion activity in early 2017.

In April 2014, we brought online the Redtail gas plant to process the associated gas produced from our wells in this area. During the third quarter of 2015, the plant's inlet capacity was expanded to 50 MMcf/d. As of September 30, 2016, the plant was processing over 18 MMcf/d.

Permian Basin

On July 27, 2016, we sold our interest in the North Ward Estes field located in Ward and Winkler counties in Texas as discussed below under "Acquisition and Divestiture Highlights".

Financing Highlights

On March 23, 2016, we completed the exchange of $477 million aggregate principal amount of our senior notes and senior subordinated notes, consisting of (i) $49 million aggregate principal amount of our 2018 Senior Subordinated Notes, (ii) $97 million aggregate principal amount of our 2019 Senior Notes, (iii) $152 million aggregate principal amount of our 2021 Senior Notes, and (iv) $179 million aggregate principal amount of our 2023 Senior Notes, for (i) $49 million aggregate principal amount of new 6.5% Convertible Senior Subordinated Notes due 2018, (ii) $97 million aggregate principal amount of new 5% Convertible Senior Notes due 2019, (iii) $152 million aggregate principal amount of new 5.75% Convertible Senior Notes due 2021, and (iv) $179 million aggregate principal amount of new 6.25% Convertible Senior Notes due 2023 (together the "New Convertible Notes"). During the second quarter of 2016, holders of the New Convertible Notes voluntarily converted all $477 million aggregate principal amount of the New Convertible Notes for approximately 41.8 million shares of our common stock. Upon conversion, we paid $46 million in cash consisting of early conversion payments to the holders of the notes, as well as all accrued and unpaid interest on such notes.

On June 29, 2016 and July 1, 2016, we completed the exchange of $1.1 billion aggregate principal amount of our senior notes, convertible senior notes and senior subordinated notes consisting of (i) $26 million aggregate principal amount of our 6.5% Senior Subordinated Notes due 2018, (ii) $42 million aggregate principal amount of our 5% Senior Notes due 2019, (iii) $688 million aggregate principal amount of our 1.25% Convertible Senior Notes due 2020, (iv) $174 million aggregate principal amount of our 5.75% Senior Notes due 2021, and (v) $163 million aggregate principal amount of our 6.25% Senior Notes due 2023, for (i) $26 million aggregate principal amount of new 6.5% Mandatory Convertible Senior Subordinated Notes due 2018, (ii) $42 million aggregate principal amount of new 5% Mandatory Convertible Senior Notes due 2019, (iii) $688 million aggregate principal amount of new 1.25% Mandatory Convertible Senior Notes due 2020, (iv) $174 million aggregate principal amount of new 5.75% Mandatory Convertible Senior Notes due 2021, and (v) $163 million aggregate principal amount of new 6.25% Mandatory Convertible Senior Notes due 2023 (together the “Mandatory Convertible Notes”). During the initial 25 trading day observation period from June 23, 2016 through July 28, 2016, $333 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 33.2 million shares of our common stock pursuant to the terms of the Mandatory Convertible Notes. Upon conversion, we paid $3 million in cash consisting of all accrued and unpaid interest on such notes.

The July 1, 2016 note exchange transactions triggered an ownership shift as defined under Section 382 of the Internal Revenue Code due to the “deemed share issuance” that resulted from the note exchanges. This triggering event will limit our usage of certain of our net operating losses and tax credits in the future. Accordingly, we recognized a write-down of deferred tax assets totaling $315 million and recorded a valuation allowance on our net operating losses of $139 million during the third quarter of 2016, resulting in a total non-cash charge of $454 million. We expect to record an additional valuation allowance of approximately $14 million in the fourth quarter of 2016, bringing the total non-cash charge related to the Section 382 limitation to approximately $468 million.

Upon closing of the sale of the North Ward Estes field on July 27, 2016, as discussed below under “Acquisition and Divestiture Highlights”, the borrowing base under Whiting Oil and Gas’ credit agreement was reduced from $2.75 billion to $2.6 billion. In October 2016, the borrowing base under the facility was further reduced from $2.6 billion to $2.5 billion in connection with the November 1, 2016 regular borrowing base redetermination. There were no changes to the $2.5 billion aggregate commitments under the facility or to any other terms of the credit agreement.

On August 12, 2016, we completed the exchange of (i) $13 million aggregate principal amount of our 6.5% Mandatory Convertible Senior Subordinated Notes due 2018 which had a conversion price of $8.75 per share (equivalent to 114.29 common shares per $1,000 principal amount of the notes) for shares of our common stock at an issuance price of $7.77 per share (equivalent to 128.69 common shares per $1,000 principal amount of the notes) and (ii) $25 million aggregate principal amount of our 5% Mandatory Convertible Senior Notes due 2019 which had a conversion price of $8.79 per share (equivalent to 113.72 common shares per $1,000 principal amount of the notes) for shares of our common stock at an issuance price of $7.80 per share (equivalent to 128.17 shares per $1,000 principal amount of the notes). Upon acceptance of this inducement offer by the holders of the notes, such notes were immediately cancelled in exchange for approximately 4.9 million shares of our common stock and we paid $1 million in cash consisting of all accrued and unpaid interest on such notes.

Refer to the “Long-Term Debt” footnote in the notes to consolidated financial statements for more information on these financing transactions.

Acquisition and Divestiture Highlights

On July 27, 2016, we completed the sale of our interest in our enhanced oil recovery project in the North Ward Estes field in Ward and Winkler counties of Texas, including our interest in certain CO2 properties in the McElmo Dome field in Colorado, two contracts for the supply and delivery of CO2, and certain other related assets and liabilities (the “North Ward Estes Properties”) for a cash purchase price of $300 million (before closing adjustments). The sale was effective July 1, 2016 and resulted in a pre-tax loss on sale of $188 million. In addition to the cash purchase price, the buyer has agreed to pay us $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 “Contingent Payment”). The Contingent Payment will be made at the option of the buyer either in cash on July 31, 2018 or in the form of a secured promissory note, accruing interest at 8% per annum with a maturity date of July 29, 2022. We used the net proceeds from the sale to repay a portion of the debt outstanding under our credit agreement. The North Ward Estes Properties consisted of estimated proved reserves of 120.3 MMBOE as of December 31, 2015, representing 15% of our proved reserves as of that date, and generated 6% (or 8.6 MBOE/d) of our June 2016 average daily net production.

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Results of Operations

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015

	Nine Months Ended September 30, 2016	2015
Net production:		
Oil (MMBbl)	26.4	36.3
NGLs (MMBbl)	5.0	3.9
Natural gas (Bcf)	31.2	30.5
Total production (MMBOE)	36.6	45.3
Net sales (in millions):		
Oil (1)	$ 864.6	$ 1,547.8
NGLs	38.5	52.2
Natural gas	39.2	74.5
Total oil, NGL and natural gas sales	$ 942.3	$ 1,674.5
Average sales prices:		
Oil (per Bbl) (1)	$ 32.70	$ 42.63
Effect of oil hedges on average price (per Bbl)	4.93	4.06
Oil net of hedging (per Bbl)	$ 37.63	$ 46.69
Weighted average NYMEX price (per Bbl) (2)	$ 40.84	$ 51.12
NGLs (per Bbl)	$ 7.78	$ 13.38
Natural gas (per Mcf)	$ 1.25	$ 2.44
Weighted average NYMEX price (per Mcf) (2)	$ 2.30	$ 2.78
Costs and expenses (per BOE):		
Lease operating expenses	$ 8.40	$ 9.61
Production taxes	$ 2.16	$ 3.21
Depreciation, depletion and amortization	$ 24.61	$ 20.36
General and administrative	$ 3.07	$ 2.95

(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 decreased $732 million to $942 million when comparing the first nine months of 2016 to the same period in 2015. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes decreased 27%, while our NGL and natural gas sales volumes increased 27% and 2%, respectively, between periods. The oil volume decrease between periods was primarily attributable to normal field production decline across several of our areas resulting from reduced drilling and completion activity during 2015 and the first nine months of 2016 in response to the depressed commodity price environment. In addition, we completed several non-core oil and gas property divestitures during 2015 and 2016, which negatively impacted oil production in the first nine months of 2016 by 1,750 MBbl. These decreases were partially offset by new wells drilled and completed in the Williston Basin and DJ Basin which added 4,495 MBbl and 545 MBbl, respectively, of oil production during the first nine months of 2016 as compared to the first nine months of 2015. Our NGL sales volume increases between periods generally relate to additional volumes processed as more wells were connected to gas processing plants in the Williston Basin, as well as new wells drilled and completed in the Williston Basin and DJ Basin over the last twelve months. 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 drilling success at our Williston Basin and DJ Basin properties which resulted in 7,480 MMcf and 1,025 MMcf, respectively, of additional gas volumes during the first nine months of 2016 as compared to the first nine months of 2015. In addition, gas volumes increased between periods as more wells were connected to gas processing plants in the Williston Basin over the last twelve months in an effort to increase our overall gas capture rate in this area. These gas volume increases were largely offset by the 2015 property divestitures, which negatively impacted gas production in the first nine months of 2016 by 5,435 MMcf, as well as normal field production decline across several of our areas.

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In addition to production-related decreases in net revenue there were also significant decreases in the average sales price realized for oil, NGLs and natural gas in the first nine months of 2016 compared to 2015. Our average price for oil before the effects of hedging decreased 23%, our average price for NGLs decreased 42% and our average price for natural gas decreased 49% between periods.

Loss on Sale of Properties. During the first nine months of 2016, we sold our interest in the North Ward Estes Properties for net cash proceeds of $295 million, which resulted in a pre-tax loss on sale of $188 million. There were no other property divestitures resulting in a significant gain or loss on sale during the first nine months of 2016. During the first nine months of 2015, we sold our interests in certain non-core producing oil and gas wells for aggregate net proceeds of $339 million, which resulted in a pre-tax loss on sale of $62 million.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during the first nine months of 2016 were $308 million, a $128 million decrease over the same period in 2015. This decrease was primarily due to (i) $57 million of lower LOE attributable to properties that we divested, (ii) a $55 million decline in the costs of oilfield goods and services resulting from cost reduction measures we have implemented as well as the general downturn in the oil and gas industry and (iii) a reduction in well workover activity between periods. Workovers decreased from $42 million in the first nine months of 2015 to $26 million in the first nine months of 2016, primarily due to a reduction in well workover activity at our EOR project at North Ward Estes, which we sold in July 2016.

Our lease operating expenses on a BOE basis also decreased when comparing the first nine months of 2016 to the same 2015 period. LOE per BOE amounted to $8.40 during the first nine months of 2016, which represents a decrease of $1.21 per BOE (or 13%) from the first nine months of 2015. This decrease was mainly due to the impact of property divestitures, the declining costs of goods and services in the industry and lower well workover costs, as discussed above, partially offset by lower overall production volumes between periods. The properties sold during 2015 and 2016 consisted mainly of mature oil and gas producing properties with LOE per BOE rates that were higher than our overall blended corporate rate.

Production Taxes. Our production taxes during the first nine months of 2016 were $79 million, a $66 million decrease over the same period in 2015, which decrease was primarily due to lower oil, NGL and natural gas sales 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 8.4% and 8.7% for the first nine months of 2016 and 2015, respectively. This decrease primarily relates to a reduction in the severance tax rate in North Dakota from 11.5% in 2015 to 10% in 2016.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense decreased $21 million in 2016 as compared to the first nine months of 2015. The components of our DD&A expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2016	2015
Depletion	$ 884,017	$ 898,750
Depreciation	6,348	7,355

Accretion of asset retirement obligations	10,512	15,972
Total	$ 900,877	$ 922,077

DD&A decreased between periods primarily due to $15 million in lower depletion expense. This decrease was mainly attributable to a $210 million decrease due to lower overall production volumes during the first nine months of 2016, which was partially offset by a $195 million increase in expense related to a higher depletion rate between periods. On a BOE basis, our overall DD&A rate of $24.61 for the first nine months of 2016 was 21% higher than the rate of $20.36 for the same period in 2015. The primary factors contributing to this higher DD&A rate were (i) decreases to proved and proved developed reserves over the last twelve months primarily attributable to lower average oil and natural gas prices used to calculate our reserves, (ii) $743 million in drilling and development expenditures during the past twelve months, and (iii) property divestitures. These factors that negatively impacted our DD&A rate were partially offset by impairment write-downs on proved oil and gas properties recognized in the third quarter of 2015.

Exploration and Impairment. Our exploration and impairment costs decreased $1.7 billion for the first nine months of 2016 as compared to the same period in 2015. The components of our exploration and impairment expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2016	2015
Exploration	$ 39,659	$ 108,000
Impairment	45,906	1,721,160
Total	$ 85,565	$ 1,829,160

Exploration costs decreased $68 million during the first nine months of 2016 as compared to the same period in 2015 primarily due to lower rig termination fees incurred between periods and a decrease in geology-related general and administrative expenses. Rig termination fees amounted to $18 million during the first nine months of 2016 as compared to $76 million during the first nine months of 2015. Geology-related general and administrative expenses decreased $5 million between periods.

Impairment expense for the first nine months of 2016 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $45 million during the first nine months of 2016. Impairment expense for the first nine months of 2015 primarily related to (i) $1.5 billion in non-cash impairment charges for the partial write-down of our North Ward Estes field in Texas and other non-core proved oil and gas properties primarily in Texas, Wyoming, North Dakota and Colorado that were not being developed due to depressed oil and gas prices, (ii) $70 million of leasehold amortization associated with individually insignificant unproved properties, (iii) $62 million of impairment write-downs on our CO2 development properties whose net book values exceeded their undiscounted future net cash flows and (iv) $49 million in impairment write-downs of undeveloped acreage costs for leases where we had no future plans to drill.

Goodwill Impairment. As a result of a sustained decrease in the price of our common stock during the third quarter of 2015 caused by a significant decline in crude oil and natural gas prices over that same period, we performed a goodwill impairment test as of September 30, 2015. The impairment test indicated that the fair value of our reporting unit was less than its carrying amount, and further that there was no remaining implied fair value attributable to goodwill. Based on these results, we recorded a non-cash impairment charge of $870 million in the third quarter of 2015 to reduce the carrying value of goodwill to zero.

General and Administrative. 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,	
	2016	2015
General and administrative expenses	$ 203,454	$ 240,068
Reimbursements and allocations	(91,227)	(106,280)
General and administrative expenses, net	$ 112,227	$ 133,788

G&A expenses before reimbursements and allocations decreased $37 million during the first nine months of 2016 as compared to the same period in 2015 primarily due to lower employee compensation, savings realized as a result of cost reduction measures we have implemented and the impact of property divestitures. Employee compensation decreased $22 million for the first nine months of 2016 as compared to the same period in 2015 due to reductions in personnel over the past twelve months. The decrease in reimbursements and allocations for the first nine months of 2016 was the result of a lower number of field workers on Whiting-operated properties due to reduced drilling activity and property divestitures over the past twelve months.

Our general and administrative expenses on a BOE basis, however, increased when comparing the first nine months of 2016 to the same 2015 period. G&A expense per BOE amounted to $3.07 during the first nine months of 2016, which represents an increase of $0.12 per BOE (or 4%) from the first nine months of 2015. This increase was mainly due to lower overall production volumes between periods, partially offset by lower employee compensation and savings realized as a result of our cost reduction measures.

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

	Nine Months Ended September 30,	
	2016	2015
Notes	$ 145,653	$ 198,105
Amortization of debt issue costs, discounts and premiums	72,389	33,058
Credit agreement	25,655	20,826
Other	1,570	45
Capitalized interest	(122)	(4,050)
Total	$ 245,145	$ 247,984

The decrease in interest expense of $3 million between periods was mainly attributable to lower interest costs incurred on our notes, partially offset by an increase in amortization of debt issue costs, discounts and premiums during the first nine months of 2016 as compared to the first nine months of 2015. The $52 million decrease in note interest was primarily due to (i) $56 million incurred during 2015 on the $1.6 billion of Kodiak Notes we assumed as part of the Kodiak Acquisition, all of which were subsequently

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repurchased during 2015, and (ii) an $11 million decrease in note interest due to the conversions of the New Convertible Notes in May 2016 and the Mandatory Convertible Notes in July and August 2016. This decrease in interest expense was partially offset by our March 2015 issuance of $1,250 million of 2020 Convertible Senior Notes and $750 million of 2023 Senior Notes, which resulted in a $15 million increase in interest expense between periods. The increase in amortization of debt issue costs, discounts and premiums of $39 million is primarily due to (i) a non-cash charge of $14 million for the acceleration of unamortized debt discounts in connection with the induced exchange of a portion of our Mandatory Convertible Notes in August 2016, (ii) $11 million of amortization of debt discount on the Mandatory Convertible Notes issued in June and July 2016, (iii) a non-cash charge of $6 million for the acceleration of unamortized debt issuance costs in connection with a reduction of the aggregate commitments under our credit agreement in March 2016 and (iv) a $5 million increase in amortization of debt discount on the 2020 Convertible Senior Notes issued in March 2015.

Our weighted average debt outstanding during the first nine months of 2016 was $5.2 billion versus $5.7 billion for the first nine months of 2015. Our weighted average effective cash interest rate was 4.4% during the first nine months of 2016 compared to 5.1% for the first nine months of 2015.

(Gain) Loss on Extinguishment of Debt. During the first nine months of 2016, we recognized a net loss on extinguishment of debt of $42 million. In March 2016, we completed the exchange of $477 million aggregate principal amount of our senior notes and senior subordinated notes for the same aggregate principal amount of New Convertible Notes, and recognized a $91 million gain on extinguishment of debt. During the second quarter of 2016, the holders of the New Convertible Notes voluntarily converted all $477 million aggregate principal amount of the New Convertible Notes for approximately 41.8 million shares of our common stock, and we recognized a $188 million loss on extinguishment of debt upon conversion. In June and July 2016, we completed the exchange of $1.1 billion aggregate principal amount of our senior notes, convertible senior notes and senior subordinated notes for the same aggregate principal amount of Mandatory Convertible Notes, and recognized a $57 million gain on extinguishment of debt. Subsequently in July, $333 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 33.2 million shares of our common stock, and we recognized a $3 million gain on extinguishment of debt upon conversion. In August 2016, we induced the exchange of an additional $38 million aggregate principal amount of the Mandatory Convertible Notes for approximately 4.9 million shares of our common stock, and we recognized a $4 million debt inducement expense. During the first nine months of 2015, we repurchased $752 million aggregate principal amount of the Kodiak Notes then outstanding, and recognized a $6 million loss on extinguishment of debt. Refer to the “Long-Term Debt” footnote in the notes to consolidated financial statements for more information on these debt transactions.

Derivative Gain, 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 gain, net amounted to a gain of $28 million for the nine months ended September 30, 2016, which consisted of a $56 million fair value gain on embedded derivatives, partially offset by a $28 million loss on commodity derivative contracts resulting from the upward shift in the futures curve of forecasted commodity prices (“forward price curve”) for crude oil from January 1, 2016 (or the 2016 date on which new contracts were entered into) to September 30, 2016. Derivative gain, net for the nine months ended September 30, 2015 consisted of a $115 million gain on commodity derivative contracts primarily due to the downward shift in the same forward price curve from January 1, 2015 (or the 2015 date on which prior year contracts were entered into) to September 30, 2015.

Refer to Item 3, “Quantitative and Qualitative Disclosures about Market Risk”, for a list of our outstanding commodity derivative contracts as of October 1, 2016.

Income Tax Expense (Benefit). Income tax expense for the first nine months of 2016 totaled $182 million as compared to a benefit of $726 million for the first nine months of 2015, an increase of $908 million that was mainly related to (i) $1.9 billion in lower pre-tax loss between periods, (ii) a $454 million non-cash charge in the third quarter of 2016 resulting from an ownership shift as defined under Section 382 of the Internal Revenue Code which will limit our usage of certain net operating losses and tax credits in the future, as discussed above under “Financing Highlights”, and (iii) the tax impact associated with the issuance and subsequent conversion of the New Convertible Notes and the Mandatory Convertible Notes during the first nine months of 2016.

Our effective tax rates for the periods ending September 30, 2016 and 2015 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Excluding the impact of the Section 382 limitation discussed above, our overall effective tax rate increased from 25.5% for the first nine months of 2015 to 27.7% for the first nine months of 2016. This increase is mainly the result of $870 million in goodwill impairment recognized during the third quarter of 2015 which is not tax deductible, partially offset by permanent tax differences associated with the issuance and subsequent conversion of the New Convertible Notes and the Mandatory Convertible Notes during the first nine months of 2016.

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Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015

	Three Months Ended September 30, 2016	2015
Net production:		
Oil (MMBbl)	7.8	11.7
NGLs (MMBbl)	1.6	1.5
Natural gas (Bcf)	9.9	9.5
Total production (MMBOE)	11.0	14.8
Net sales (in millions):		
Oil (1)	$ 283.8	$ 461.5
NGLs	14.0	15.7
Natural gas	17.8	27.0
Total oil, NGL and natural gas sales	$ 315.6	$ 504.2
Average sales prices:		
Oil (per Bbl) (1)	$ 36.58	$ 39.45
Effect of oil hedges on average price (per Bbl)	5.30	4.72
Oil net of hedging (per Bbl)	$ 41.88	$ 44.17
Weighted average NYMEX price (per Bbl) (2)	$ 44.93	$ 46.52
NGLs (per Bbl)	$ 8.65	$ 10.55
Natural gas (per Mcf)	$ 1.79	$ 2.83
Weighted average NYMEX price (per Mcf) (2)	$ 2.93	$ 2.74
Cost and expenses (per BOE):		
Lease operating expenses	$ 7.98	$ 8.50
Production taxes	$ 2.39	$ 3.00
Depreciation, depletion and amortization	$ 25.80	$ 21.40
General and administrative	$ 3.07	$ 3.03

(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 decreased $189 million to $316 million when comparing the third quarter of 2016 to the same period in 2015. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes decreased 34%, while our NGL and natural gas sales volumes increased 9% and 4%, respectively, between periods. The oil volume decrease between periods was primarily attributable to normal field production decline across several of our areas resulting from reduced drilling and completion activity during 2016 in response to the depressed commodity price environment. In addition, we completed several non-core oil and gas property divestitures during the past twelve months, which negatively impacted oil production in the third quarter of 2016 by 755 MBbl. These decreases were partially offset by new wells drilled and completed in the Williston Basin and DJ Basin which added 1,290 MBbl and 285 MBbl, respectively, of oil production during the third quarter of 2016 as compared to the third quarter of 2015. Our NGL sales volume increases between periods generally relate to additional volumes processed as more wells were connected to gas processing plants in the Williston Basin, as well as new wells drilled and completed in the Williston Basin and DJ Basin over the last twelve months. 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 drilling success at our Williston Basin and DJ Basin properties which resulted in 2,040 MMcf and 340 MMcf, respectively, of additional gas volumes during the third quarter of 2016 as compared to the third quarter of 2015. In addition, gas volumes increased between periods as more wells were connected to gas processing plants in the Williston Basin over the last twelve months in an effort to increase our overall gas capture rate in this area. These gas volume increases were largely offset by property divestitures over the past twelve months, which negatively impacted gas production in the third quarter of 2016 by 550 MMcf, as well as normal field production decline across several of our areas.

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In addition to production-related decreases in net revenue there were also significant decreases in the average sales price realized for oil, NGLs and natural gas in the third quarter of 2016 compared to 2015. Our average price for oil before the effects of hedging decreased 7%, our average price for NGLs decreased 18%, and our average price for natural gas decreased 37% between periods.

Loss on Sale of Properties. During the third quarter of 2016, we sold our interest in the North Ward Estes Properties for net cash proceeds of $295 million, which resulted in a pre-tax loss on sale of $188 million. There were no other property divestitures resulting in a significant gain or loss on sale during the third quarter of 2016 or 2015.

Lease Operating Expenses. Our lease operating expenses during the third quarter of 2016 were $88 million, a $38 million decrease over the same period in 2015. This decrease was primarily due to (i) $17 million of lower LOE attributable to properties that we divested, (ii) a $16 million decline in the costs of oilfield goods and services resulting from cost reduction measures we have implemented as well as the general downturn in the oil and gas industry and (iii) a reduction in well workover activity between periods. Workovers decreased from $13 million in the third quarter of 2015 to $8 million in the third quarter of 2016, primarily due to a reduction in well workover activity at our EOR project at North Ward Estes, which we sold in July 2016, and at our Parshall field.

Our lease operating expenses on a BOE basis also decreased when comparing the third quarter of 2016 to the same 2015 period. LOE per BOE amounted to $7.98 during the third quarter of 2016, which represents a decrease of $0.52 per BOE (or 6%) from the third quarter of 2015. This decrease was mainly due to the impact of property divestitures, the declining costs of goods and services in the industry and lower well workover costs, as discussed above, partially offset by lower overall production volumes between periods. The properties sold during 2015 and 2016 consisted mainly of mature oil and gas producing properties with LOE per BOE rates that were higher than our overall blended corporate rate.

Production Taxes. Our production taxes during the third quarter of 2016 were $26 million, an $18 million decrease over the same period in 2015, which decrease was primarily due to lower oil, NGL and natural gas sales 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 8.4% and 8.8% for the third quarter of 2016 and 2015, respectively. This decrease primarily relates to a reduction in the severance tax rate in North Dakota from 11.5% in 2015 to 10% in 2016.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization expense decreased $32 million in 2016 as compared to the third quarter of 2015. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended September 30,	
	2016	2015
Depletion	$ 279,169	$ 309,698
Depreciation	2,120	2,962
Accretion of asset retirement obligations	3,280	3,487
Total	$ 284,569	$ 316,147

DD&A decreased between periods primarily due to $31 million in lower depletion expense between periods. Of this decrease, $95 million related to a decrease in our overall production volumes during the third quarter of 2016, which was partially offset by a $64 million increase related to a higher depletion rate between periods. On a BOE basis, our overall DD&A rate of $25.80 for the third quarter of 2016 was 21% higher than the rate of $21.40 for the same period in 2015. The primary factors contributing to this higher DD&A rate were (i) decreases to proved and proved developed reserves over the last twelve months primarily attributable to lower average oil and natural gas prices used to calculate our reserves, (ii) $743 million in drilling and development expenditures during the past twelve months, and (iii) property divestitures. These factors that negatively impacted our DD&A rate were partially offset by impairment write-downs on proved oil and gas properties recognized in the third quarter of 2015.

Exploration and Impairment Costs. Our exploration and impairment costs decreased $1.7 billion for the third quarter of 2016 as compared to the same period in 2015. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended September 30,	
	2016	2015
Exploration	$ 8,747	$ 21,072
Impairment	15,546	1,669,607
Total	$ 24,293	$ 1,690,679

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Exploration costs decreased $12 million during the third quarter of 2016 as compared to the same period in 2015 primarily due to a $9 million decrease in rig termination fees incurred between periods.

Impairment expense for the third quarter of 2016 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $15 million during the third quarter of 2016. Impairment expense for the third quarter of 2015 primarily related to (i) $1.5 billion in non-cash impairment charges for the partial write-down of our North Ward Estes field in Texas and other non-core proved oil and gas properties primarily in Texas, Wyoming, North Dakota and Colorado that were not being developed due to depressed oil and gas prices, (ii) $62 million of impairment write-downs on our CO2 development properties whose net book values exceeded their undiscounted future net cash flows, (iii) $48 million in impairment write-downs of undeveloped acreage costs for leases where we had no future plans to drill and (iv) $20 million of leasehold amortization associated with individually insignificant unproved properties.

Goodwill Impairment. As a result of a sustained decrease in the price of our common stock during the third quarter of 2015 caused by a significant decline in crude oil and natural gas prices over that same period, we performed a goodwill impairment test as of September 30, 2015. The impairment test indicated that the fair value of our reporting unit was less than its carrying amount, and further that there was no remaining implied fair value attributable to goodwill. Based on these results, we recorded a non-cash impairment charge of $870 million in the third quarter of 2015 to reduce the carrying value of goodwill to zero.

General and Administrative Expenses. We report general and administrative 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,	
	2016	2015
General and administrative expenses	$ 62,251	$ 77,380
Reimbursements and allocations	(28,343)	(32,559)
General and administrative expenses, net	$ 33,908	$ 44,821

G&A expenses before reimbursements and allocations decreased $15 million during the third quarter of 2016 as compared to the same period in 2015 primarily due to lower employee compensation, savings realized as a result of cost reduction measures we have implemented and the impact of property divestitures. Employee compensation decreased $11 million for the third quarter of 2016 as compared to the same period in 2015 due to reductions in personnel over the past twelve months. The decrease in reimbursements and allocations for the third quarter of 2016 was the result of a lower number of field workers on Whiting-operated properties due to reduced drilling activity and property divestitures over the past twelve months.

Our general and administrative expenses on a BOE basis, however, increased when comparing the third quarter of 2016 to the same 2015 period. G&A expense per BOE amounted to $3.07 during the third quarter of 2016, which represents an increase of $0.04 per BOE (or 1%) from the third quarter of 2015. This increase was mainly due to lower overall production volumes between periods, partially offset by lower employee compensation and savings realized as a result of our cost reduction measures.

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

	Three Months Ended September 30,	
	2016	2015
Notes	$ 42,749	$ 68,513
Amortization of debt issue costs, discounts and premiums	33,439	13,230
Credit agreement	8,060	3,802
Other	358	26
Capitalized interest	(28)	(1,020)
Total	$ 84,578	$ 84,551

Our note interest expense decreased $26 million between periods primarily due to (i) $16 million of interest cost incurred in the third quarter of 2015 on the $800 million of 2019 Kodiak Notes we assumed as part of the Kodiak Acquisition, which were subsequently repurchased in December 2015, and (ii) a $10 million decrease in note interest due to the conversions of the New Convertible Notes in May 2016 and the Mandatory Convertible Notes in July and August 2016. Amortization of debt issue costs, discounts and premiums increased $20 million for the third quarter of 2016 compared to the same period in 2015 primarily due to (i) a non-cash charge of $14 million for the acceleration of unamortized debt discounts in connection with the induced exchange of a portion of our Mandatory Convertible Notes in August 2016 and (ii) $11 million of amortization of debt discount on the Mandatory Convertible Notes issued in

June and July 2016. These increases were partially offset by a $6 million decrease in amortization of debt discount on the 2020 Convertible Senior Notes between periods due to the exchange and subsequent conversion of these notes in June and July 2016.

Our weighted average debt outstanding during the third quarter of 2016 was $4.6 billion versus $5.5 billion for the third quarter of 2015. Our weighted average effective cash interest rate was 4.4% during the third quarter of 2016 compared to 5.3% for the third quarter of 2015.

(Gain) Loss on Extinguishment of Debt. During the third quarter of 2016, we recognized a net gain on extinguishment of debt of $47 million. In July 2016, we completed the exchange of $964 million aggregate principal amount of our senior notes, convertible senior notes and senior subordinated notes for the same aggregate principal amount of Mandatory Convertible Notes, and recognized a $48 million gain on extinguishment of debt. Subsequently in July, $333 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 33.2 million shares of our common stock, and we recognized a $3 million gain on extinguishment of debt upon conversion. In August 2016, we induced the exchange of an additional $38 million aggregate principal amount of the Mandatory Convertible Notes for approximately 4.9 million shares of our common stock, and we recognized a $4 million debt inducement expense. Refer to the "Long-Term Debt" footnote in the notes to consolidated financial statements for more information on these debt transactions.

Derivative Gain, 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 gain, net amounted to a gain of $30 million for the three months ended September 30, 2016, which consisted of a $22 million gain on commodity derivative contracts resulting from the downward shift in the forward price curve for crude oil from July 1, 2016 (or the 2016 date on which new contracts were entered into) to September 30, 2016, as well as an $8 million fair value gain on embedded derivatives. Derivative gain, net for the three months ended September 30, 2015, consisted of a $208 million gain on commodity derivative contracts primarily due to a more significant downward shift in the same forward price curve for crude oil from July 1, 2015 (or the 2015 date on which prior year contracts were entered into) to September 30, 2015.

Refer to Item 3, "Quantitative and Qualitative Disclosures about Market Risk", for a list of our outstanding commodity derivative contracts as of October 1, 2016.

Income Tax Expense (Benefit). Income tax expense for the third quarter of 2016 totaled $358 million as compared to a benefit of $595 million for the third quarter of 2015, an increase of $952 million that was mainly related to (i) $2.1 billion in lower pre-tax loss between periods, (ii) a $454 million non-cash charge in the third quarter of 2016 resulting from an ownership shift as defined under Section 382 of the Internal Revenue Code which will limit our usage of certain net operating losses and tax credits in the future, as discussed above under "Financing Highlights", and (iii) the tax impact associated with the issuance and subsequent conversion of the Mandatory Convertible Notes during the third quarter of 2016.

Our effective tax rates for the periods ending September 30, 2016 and 2015 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Excluding the impact of the Section 382 limitation discussed above, our overall effective tax rate increased from 24.2% for the third quarter of 2015 to 28.9% for the third quarter of 2016. This increase is mainly the result of $870 million in goodwill impairment recognized during the third quarter of 2015 which is not tax deductible, partially offset by permanent tax differences associated with the issuance and subsequent conversion of the Mandatory Convertible Notes during the third quarter of 2016.

Liquidity and Capital Resources

Overview. At September 30, 2016, we had $18 million of cash on hand and $4.6 billion of equity, while at December 31, 2015, we had $16 million of cash on hand and $4.8 billion of equity.

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 72% and 80% of our total production in the first nine months of 2016 and 2015, 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, 2016, we had derivative contracts covering the sale of approximately 66% of our forecasted oil production volumes for the remainder of 2016. For a list of all of our outstanding commodity derivative contracts as of October 1, 2016, refer to Item 3, "Quantitative and Qualitative Disclosures about Market Risk".

During the first nine months of 2016, we generated $358 million of cash provided by operating activities, a decrease of $543 million over the same period in 2015. Cash provided by operating activities decreased primarily due to lower realized sales prices for oil, NGLs and natural gas and lower crude oil production volumes in the first nine months of 2016. These negative factors were partially offset by higher NGL and natural gas production volumes, as well as lower lease operating expenses, exploration costs, production taxes, cash interest expense and general and administrative expenses during the first nine months of 2016 as compared to the same period in 2015. Refer to “Results of Operations” for more information on the impact of prices and volumes on revenues and for more information on increases and decreases in certain expenses between periods.

During the first nine months of 2016, cash flows from operating activities plus $304 million in proceeds from the sale of oil and gas properties were used to finance $435 million of drilling and development expenditures, $150 million in net repayments under our credit agreement, $42 million of early conversion payments on our New Convertible Notes and $22 million of debt issuance costs.

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

	Nine Months Ended September 30,	
	2016	2015
Rocky Mountains	$ 395,243	$ 1,894,760
Permian Basin (1)	33,264	87,337
Other	3,138	7,791
Total incurred	$ 431,645	$ 1,989,888

(1) On July 27, 2016, we sold our North Ward Estes Properties, including all of our assets in the Permian Basin.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2016 exploration and development (“E&D”) budget is $550 million, which we expect to fund substantially with net cash provided by our operating activities, proceeds from property divestitures and, if necessary, borrowings under our credit facility. The overall budget represents a substantial decrease from the $2.3 billion we incurred on E&D expenditures during 2015. This reduced capital budget is in response to the significantly lower crude oil prices experienced during 2015 and continuing into 2016 and our plan to more closely align our capital spending with cash flows generated from operations. As part of this plan, we suspended completion operations at our Redtail field beginning in the second quarter of 2016; however, we plan to resume completions in this area in early 2017. We expect to allocate $490 million of our 2016 budget to exploration and development activity, and the remainder will be allocated to facilities, drilling rig termination fees and undeveloped acreage purchases. We believe that should additional attractive acquisition opportunities arise or E&D expenditures exceed $550 million, we will be able to finance additional capital expenditures with borrowings under our credit agreement, agreements with industry partners or divestitures of certain oil and gas property interests. 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, 2016 had a borrowing base of $2.6 billion, with aggregate commitments of $2.5 billion. In October 2016, our borrowing base under the facility was reduced to $2.5 billion in connection with the November 1, 2016 regular borrowing base redetermination, with no change to our aggregate commitments of $2.5 billion. As of September 30, 2016, we had $1.8 billion of available borrowing capacity, which was net of $650 million in borrowings and $11 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 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. Because oil and gas prices are principal inputs into the valuation of our reserves, if current and projected oil and gas prices remain at their current levels for a prolonged period or further decline, our borrowing base could be reduced at the next redetermination date, which is scheduled for May 1, 2017, or during future redeterminations. 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. The credit agreement permits us to dispose of our ownership interests in certain gas gathering and processing plants located in North Dakota without reducing the borrowing base.

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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 ours. As of September 30, 2016, $39 million was available for additional letters of credit under the agreement.

The credit agreement provides for interest only payments until December 2019, when the credit agreement expires and all outstanding borrowings are due. Interest under the revolving credit facility 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. 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 revolving credit facility.

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	1.00%	2.00%	0.50%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.50%	2.50%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.75%	2.75%	0.50%
Greater than or equal to 0.90 to 1.0	2.00%	3.00%	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. However, the credit agreement permits us and certain of our subsidiaries to issue second lien indebtedness of up to $1.0 billion subject to certain conditions and limitations. 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). The credit agreement requires 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, (ii) a total senior secured debt to the last four quarters' EBITDAX ratio of less than 3.0 to 1.0 during the Interim Covenant Period (defined below), and thereafter a total debt to EBITDAX ratio of less than 4.0 to 1.0, and (iii) a ratio of the last four quarters' EBITDAX to consolidated cash interest charges of not less than 2.25 to 1.0 during the Interim Covenant Period. Under the credit agreement, the "Interim Covenant Period" is defined as the period from June 30, 2015 until the earlier of (a) April 1, 2018 or (b) the commencement of an investment-grade debt rating period (as defined in the credit agreement). We were in compliance with our covenants under the credit agreement as of September 30, 2016. 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.

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

Senior Notes and Senior Subordinated 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% 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 2019 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” and together with the Senior Notes, the “Nonconvertible Whiting Notes”).

Exchange of Senior Notes and Senior Subordinated Notes for Convertible Notes. On March 23, 2016, we completed the exchange of $477 million aggregate principal amount of our Senior Notes and 2018 Senior Subordinated Notes, consisting of (i) $49 million aggregate principal amount of our 2018 Senior Subordinated Notes, (ii) $97 million aggregate principal amount of our 2019 Senior Notes, (iii) $152 million aggregate principal amount of our 2021 Senior Notes, and (iv) $179 million aggregate principal amount of our 2023 Senior Notes, for (i) $49 million aggregate principal amount of new 6.5% Convertible Senior Subordinated Notes due 2018, (ii) $97 million aggregate principal amount of new 5% Convertible Senior Notes due 2019, (iii) $152 million aggregate principal amount of new 5.75% Convertible Senior Notes due 2021, and (iv) $179 million aggregate principal amount of new 6.25% Convertible Senior Notes due 2023 (together the “New Convertible Notes”). During the second quarter of 2016, holders of the New Convertible Notes voluntarily converted all $477 million aggregate principal amount of the New Convertible Notes for approximately 41.8 million shares of our common stock. As of June 30, 2016, no New Convertible Notes remained outstanding.

Exchange of Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes. On July 1, 2016, we completed the exchange of $405 million aggregate principal amount of our Senior Notes and 2018 Senior Subordinated Notes for the same aggregate

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principal amount of new mandatory convertible senior notes and mandatory convertible senior subordinated notes. Refer to "Exchange of Senior Notes, Convertible Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes" below for more information on these exchange transactions and the terms of the new mandatory convertible notes.

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"). On June 29, 2016, we completed the exchange of $129 million aggregate principal amount of our 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes, and on July 1, 2016, we completed the exchange of $559 million aggregate principal amount of our 2020 Convertible Senior Notes for the same aggregate principal amount of new mandatory convertible senior notes. Refer to "Exchange of Senior Notes, Convertible Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes" below for more information on these exchange transactions and the terms of the new mandatory convertible notes.

For the remaining $562 million aggregate principal amount of 2020 Convertible Senior Notes, we have the option to settle conversions of the 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 an initial conversion rate of 25.6410 shares of our common stock per $1,000 principal amount of the notes, which is equivalent to an initial conversion price of approximately $39.00. 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, 2016, none of the contingent conditions allowing holders of the 2020 Convertible Senior Notes to convert these notes had been met.

Exchange of Senior Notes, Convertible Senior Notes and Senior Subordinated Notes for Mandatory Convertible Notes. On June 29, 2016 we completed the exchange of $129 million aggregate principal amount of our 2020 Convertible Senior Notes for the same aggregate principal amount of new 1.25% Mandatory Convertible Senior Notes due 2020, Series 2 (the "2020 Mandatory Convertible Notes, Series 2"). On July 1, 2016, we completed the exchange of $964 million aggregate principal amount of our Senior Notes, 2020 Convertible Senior Notes and 2018 Senior Subordinated Notes, consisting of (i) $26 million aggregate principal amount of our 2018 Senior Subordinated Notes, (ii) $42 million aggregate principal amount of our 2019 Senior Notes, (iii) $559 million aggregate principal amount of our 2020 Convertible Senior Notes, (iv) $174 million aggregate principal amount of our 2021 Senior Notes, and (v) $163 million aggregate principal amount of our 2023 Senior Notes, for (i) $26 million aggregate principal amount of new 6.5% Mandatory Convertible Senior Subordinated Notes due 2018 (the "2018 Mandatory Convertible Notes"), (ii) $42 million aggregate principal amount of new 5% Mandatory Convertible Senior Notes due 2019 (the "2019 Mandatory Convertible Notes"), (iii) $559 million aggregate principal amount of new 1.25% Mandatory Convertible

Senior Notes due 2020, Series 1 (the "2020 Mandatory Convertible Notes, Series 1" and together with the 2020 Mandatory Convertible Notes, Series 2, the "2020 Mandatory Convertible Notes"), (iv) $174 million aggregate principal amount of new 5.75% Mandatory Convertible Senior Notes due 2021 (the "2021 Mandatory Convertible Notes"), and (v) $163 million aggregate principal amount of new 6.25% Mandatory Convertible Senior Notes due 2023 (the "2023 Mandatory Convertible Notes" and together with the 2018 Mandatory Convertible Notes, the 2019 Mandatory Convertible Notes, the 2020 Mandatory Convertible Notes and the 2021 Mandatory Convertible Notes, the "Mandatory Convertible Notes").

The redemption provisions, covenants, interest payments and maturity terms applicable to each series of Mandatory Convertible Notes are substantially identical to those applicable to the corresponding series of Senior Notes, 2020 Convertible Senior Notes and 2018 Senior Subordinated Notes except that the 2020 Mandatory Convertible Notes will mature on June 5, 2020 unless earlier converted in accordance with their terms.

The Mandatory Convertible Notes contain mandatory conversion features whereby four percent of the aggregate principal amount of the Mandatory Convertible Notes were converted into shares of our common stock for each day of the 25 trading day period that commenced on June 23, 2016 (the "Observation Period") if the daily volume weighted average price (the "Daily VWAP") (as defined in the indentures governing the Mandatory Convertible Notes) of our common stock on such day, rounded to four decimal places for the 2020 Mandatory Convertible Notes and rounded to two decimal places for the 2018 Mandatory Convertible Notes, the 2019 Mandatory Convertible Notes, the 2021 Mandatory Convertible Notes and the 2023 Mandatory Convertible Notes, was above $8.75

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(the "Threshold Price"). Upon conversion, the common stock issue price per share is equal to the higher of (i) the Daily VWAP for our common stock for such trading day multiplied by one plus zero for the 2018 Mandatory Convertible Notes, one plus 0.5% for the 2019 Mandatory Convertible Notes, one plus 8.0% for the 2020 Mandatory Convertible Notes, one plus 2.5% for the 2021 Mandatory Convertible Notes and one plus 3.5% for the 2023 Mandatory Convertible Notes or (ii) $8.75 for the 2018 Mandatory Convertible Notes (equivalent to 114.29 common shares per $1,000 principal amount of the notes), $8.79 for the 2019 Mandatory Convertible Notes (equivalent to 113.72 common shares per $1,000 principal amount of the notes), $9.45 for the 2020 Mandatory Convertible Notes (equivalent to 105.82 common shares per $1,000 principal amount of the notes), $8.97 for the 2021 Mandatory Convertible Notes (equivalent to 111.50 common shares per $1,000 principal amount of the notes) and $9.06 for the 2023 Mandatory Convertible Notes (equivalent to 110.42 common shares per $1,000 principal amount of the notes) (the "Minimum Conversion Prices").

During the Observation Period, the Daily VWAP of our common stock was above the Threshold Price (i) for 7 of the 25 trading days for the 2018 Mandatory Convertible Notes, the 2019 Mandatory Convertible Notes, the 2021 Mandatory Convertible Notes and the 2023 Mandatory Convertible Notes and (ii) for 8 of the 25 trading days for the 2020 Mandatory Convertible Notes. As a result, $333 million aggregate principal amount of the Mandatory Convertible Notes were converted into approximately 33.2 million shares of our common stock.

After the Observation Period, we have the right to mandatorily convert any remaining Mandatory Convertible Notes if the Daily VWAP of our common stock exceeds $8.75 for at least 20 trading days during a 30 consecutive trading day period and holders have the right to convert the Mandatory Convertible Notes at any time. The conversion price after the Observation Period will be the Minimum Conversion Price for each applicable series of Mandatory Convertible Notes. As of September 30, 2016, none of the conditions allowing us to convert the remaining Mandatory Convertible Notes had been met, and no holders of the Mandatory Convertible Notes had voluntarily converted any such notes.

Induced Exchange of Mandatory Convertible Notes. On August 12, 2016, we completed the exchange of (i) $13 million aggregate principal amount of our 2018 Mandatory Convertible Notes which had a conversion price of $8.75 per share (equivalent to 114.29 common shares per $1,000 principal amount of the notes) for shares of our common stock at an issuance price of $7.77 per share (equivalent to 128.69 common shares per $1,000 principal amount of the notes) and (ii) $25 million aggregate principal amount of our 2019 Mandatory Convertible Notes which had a conversion price of $8.79 per share (equivalent to 113.72 common shares per $1,000 principal amount of the notes) for shares of our common stock at an issuance price of $7.80 per share (equivalent to 128.17 shares per $1,000 principal amount of the notes). Upon acceptance of this inducement offer by the holders of the notes, such notes were immediately cancelled in exchange for approximately 4.9 million shares of our common stock.

The indentures governing the Nonconvertible Whiting Notes and certain of the Mandatory Convertible 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 or our subordinated debt, 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, 2016. 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, 2016 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, 2015.

	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)	$ 4,451,476	$ -	$ 1,247,156	$ 2,678,691	$ 525,629
Cash interest expense on debt (2)	731,357	188,754	332,937	160,388	49,278
Asset retirement obligations (3)	171,657	7,368	11,410	8,072	144,807
Water disposal agreement (4)	140,110	14,506	37,762	40,635	47,207
Purchase obligations (5)	32,162	7,280	15,312	9,570	-
Pipeline transportation agreements (6)	45,036	5,369	10,738	10,738	18,191
Drilling rig contracts (7)	43,406	41,216	2,190	-	-
Leases (8)	23,567	7,362	14,517	1,688	-
Total	$ 5,638,771	$ 271,855	$ 1,672,022	$ 2,909,782	$ 785,112

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

(2) Cash interest expense on the Nonconvertible Whiting Notes is estimated assuming no principal repayment until the due dates of the instruments. Cash interest expense on the 2020 Convertible Senior Notes and the Mandatory Convertible Notes is estimated assuming no principal repayments or conversions prior to maturity. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the December 2019 instrument due date and is estimated at a fixed interest rate of 2.9%.

(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 and facilities.

(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. The obligations reported above represent our minimum financial commitments pursuant to the terms of this contract, however, our actual expenditures under this contract may exceed the minimum commitments presented above.

(5) We have two take-or-pay purchase agreements, of which one agreement expires in 2016 and one 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 these agreements, we are obligated to purchase a minimum volume of water or else pay for any deficiencies at the price stipulated in the contract. The purchasing 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.

(6) We have two pipeline transportation agreements with one supplier, expiring in 2024 and 2025, whereby 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.

(7) As of September 30, 2016, we had five drilling rigs under long-term contract, all of which expire in 2017. As of September 30, 2016, early termination of these contracts would require termination penalties of $36 million, which would be in lieu of paying the remaining drilling commitments under these contracts.

(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, 36,500 square feet of office space in Dickinson, North Dakota expiring in 2020, and 36,300 square feet of additional administrative office space in Denver, Colorado assumed in the Kodiak Acquisition expiring in October 2016.

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.

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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 in the notes to 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, 2015. The following is a material update to such critical accounting policies and estimates:

Derivative Instruments and Hedging Activity. 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. We do not currently apply hedge accounting to any of our outstanding derivative instruments, and as a result, all changes in derivative fair values are recognized currently in earnings.

We determine the fair value of our derivative instruments measured at fair value utilizing third-party valuation specialists. We review these valuations, including the related model inputs and assumptions, and analyze changes in fair value measurements between periods. We corroborate such inputs, calculations and fair value changes using various methodologies, and review unobservable inputs for reasonableness utilizing relevant information from other published sources. When available, we utilize counterparty valuations to assess the reasonableness of our valuations. The values we report in our financial statements change as the assumptions used in these valuations are revised to reflect changes in market conditions (particularly those for oil and natural gas futures) or other factors, many of which are beyond our control.

We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We primarily utilize costless collars which are generally placed with major financial institutions, as well as crude oil sales and delivery contracts. We use hedging to help ensure that we have adequate cash flow to fund our capital programs and manage returns on our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While the use of these hedging arrangements limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We evaluate the ability of our counterparties to perform at the inception of a hedging relationship and on a periodic basis as appropriate.

We value our costless collars using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. We value our long-term crude oil sales and delivery contracts based on an income approach, which considers various assumptions, including quoted forward prices for commodities, market differentials for crude oil and U.S. Treasury rates. The discount rates used in the fair values of these instruments include a measure of nonperformance risk by the counterparty or us, as appropriate.

In addition, we evaluate the terms of our convertible debt and other contracts, if any, to determine whether they contain embedded components that are required to be bifurcated and accounted for separately as derivative financial instruments.

We valued the embedded derivatives related to our convertible notes using a binomial lattice model which considered various inputs including (i) our common stock price, (ii) risk-free rates based on U.S. Treasury rates, (iii) recovery rates in the event of default, (iv) default intensity and (v) volatility of our common stock.

We also have an embedded derivative related to our purchase and sale agreement with the buyer of the North Ward Estes Properties, which includes a contingent payment linked to NYMEX crude oil prices. We value this embedded derivative using a modified Black-Scholes swaption pricing model which considers various assumptions, including quoted forward prices for commodities, time value and volatility factors. The discount rate used in the fair value of this instrument includes a measure of the counterparty's nonperformance risk.

Effects of Inflation and Pricing

During 2015 and continuing into 2016, we experienced decreased costs due to a decrease in demand for oil field products and services in response to the sustained depressed commodity price environment. 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.

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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 prices for oil and natural gas 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.

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; the potential impact of federal debt reduction initiatives and tax reform legislation being considered by the U.S. Federal Government that could have a negative effect on the oil and gas industry; 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; 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 this Quarterly Report on Form 10-Q and in Item 1A of our Annual Report on Form 10 K for the period ended December 31, 2015. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Quarterly Report on Form 10-Q.

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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 2016, our income (loss) before income taxes for the nine months ended September 30, 2016 would have moved up or down $86 million for each 10% change in oil prices per Bbl, $4 million for each 10% change in NGL prices per Bbl and $4 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, 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.

Commodity Derivative Contracts

Crude Oil Costless Collars. 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 commodity derivative instruments at September 30, 2016, was a net asset of $34 million. A hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve for crude oil as of September 30, 2016 would cause a decrease of $55 million or an increase of $52 million, respectively, in this fair value asset.

Our outstanding commodity derivative contracts as of October 1, 2016 are summarized below:

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Sub-Floor/Floor/Ceiling
Three-way collars (1)	Crude oil	10/2016 to 12/2016	1,400,000	$43.75/$53.75/$74.40
	Crude oil	01/2017 to 03/2017	950,000	$34.21/$44.47/$60.06
	Crude oil	04/2017 to 06/2017	950,000	$34.21/$44.47/$60.06
	Crude oil	07/2017 to 09/2017	950,000	$34.21/$44.47/$60.06
	Crude oil	10/2017 to 12/2017	950,000	$34.21/$44.47/$60.06
Collars	Crude oil	10/2016 to 12/2016	250,000	$51.00/$63.48
	Crude oil	01/2017 to 03/2017	250,000	$53.00/$70.44
	Crude oil	04/2017 to 06/2017	250,000	$53.00/$70.44
	Crude oil	07/2017 to 09/2017	250,000	$53.00/$70.44
	Crude oil	10/2017 to 12/2017	250,000	$53.00/$70.44

(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 are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015 and have not materially changed since that report was filed.

In March 2015, we issued 1.25% Convertible Senior Notes due April 2020 (the "2020 Convertible Senior Notes"). As the interest rate on these notes is fixed at 1.25%, we are not subject to any direct risk of loss related to fluctuations in interest rates. However, changes in interest rates do affect the fair value of this debt instrument, which could impact the amount of gain or loss that we recognize in earnings upon conversion of the notes. Refer to the "Long-Term Debt" and "Fair Value Measurements" footnotes in the notes to consolidated financial statements for more information on the material terms and fair values of the 2020 Convertible Senior Notes.

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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, 2016. Based upon their evaluation of these disclosures 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, 2016 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, 2016 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

Whiting is subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. 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.

After the closing of the Kodiak Acquisition, the U.S. Environmental Protection Agency (the "EPA") contacted us to discuss Kodiak's responses to a June 2014 information request from the EPA under Section 114(a) of the Federal Clean Air Act, as amended (the "CAA"). In addition, in July 2015 and March 2016, we received information requests from the EPA under Section 114(a) of the CAA. The information requests relate to tank batteries used in our Williston Basin operations and our compliance with certain regulatory requirements at those locations for the control of air pollutant emissions from those facilities. We have responded to the EPA's July 2015 and March 2016 information requests, and such responses were also provided to the North Dakota Department of Health ("NDDoH"), with whom the EPA was coordinating in making the requests. The EPA has sole authority to enforce CAA violations on the Fort Berthold Indian Reservation in North Dakota, and, to date, no formal federal enforcement action has been commenced in connection with this matter for our North Dakota tribal properties beyond receipt of the noted information requests. We are unable to predict the ultimate outcome of possible federal enforcement with respect to our North Dakota tribal properties, or other exclusively federal requirements at any of our North Dakota properties, at this time, which could result in civil penalties or require us to undertake corrective actions, or both.

In connection with the above EPA inquiries, on October 18, 2016, the NDDoH concurrently filed in the North Dakota District Court for Burleigh County (the "Court") a complaint against, and a settlement with, us regarding tank operation and other inspection-related alleged violations of North Dakota's air pollution control laws. This complaint and settlement addresses approximately 94 percent of our North Dakota properties but does not address our North Dakota tribal property operations or exclusively federal requirements applicable to all of our North Dakota properties, which are governed by the EPA. In the settlement, we and a significant number of North Dakota operators have worked with the NDDoH to develop inspection and repair measures to detect and prevent emissions from facilities even more effectively going forward. We believe these measures will be included in settlements between the NDDoH and each participating operator. We and the NDDoH, pending Court approval of the settlement, have agreed that we will pay a civil penalty of $1.2 million, of which $1.1 million may be reduced by up to 60 percent by early and continued implementation of the aforementioned inspection and repair measures and a quality control policy. Whiting anticipates being able to qualify for all available penalty reductions. The settlement is not an admission by Whiting of any violation.

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, 2015. The following is a material update to such risk factors:

Our convertible senior notes and our convertible senior subordinated notes may adversely affect the market price of our common stock.

The market price of our common stock is likely to be influenced by our convertible senior notes and convertible senior subordinated notes. For example, the market price of our common stock could become more volatile and could be depressed by:

- investors’ anticipation of the potential resale in the market of a substantial number of additional shares of our common stock received upon conversion of our convertible senior notes and convertible senior subordinated notes;
- possible sales of our common stock by investors who view our convertible senior notes and convertible senior subordinated notes as a more attractive means of equity participation in us than owning shares of our common stock; and
- hedging or arbitrage trading activity that may develop involving our convertible senior notes, our convertible senior subordinated notes and our common stock.

Item 6. Exhibits

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

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 27th day of October, 2016.

WHITING PETROLEUM CORPORATION

By /s/ James J. Volker
James J. Volker
Chairman, President and Chief Executive Officer

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

By /s/ Brent P. Jensen
Brent P. Jensen
Vice President, Finance and Treasurer

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(2.1)	Purchase and Sale Agreement, dated July 27, 2016, by and between Whiting Oil and Gas Corporation and Four Corners Petroleum II, LLC, effective as of July 1, 2016, including Exhibit K, the Form of Promissory Note for Additional Consideration [Incorporated by reference to Exhibit 2.1 to Whiting Petroleum Corporation's Current Report on Form 8-K filed on August 2, 2016 (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, 2016 are filed herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of September 30, 2016 and December 31, 2015, (ii) the Consolidated Statements of Operations for the Three and Nine Months Ended September 30, 2016 and 2015, (iii) the Consolidated Statements of Cash Flows for the Nine Months Ended September 30, 2016 and 2015, (iv) the Consolidated Statements of Equity for the Nine Months Ended September 30, 2016 and 2015 and (v) Notes to Consolidated Financial Statements.