WHITING PETROLEUM CORP
Form 10-Q
July 30, 2015
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 June 30, 2015

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 July 15, 2015: 204,142,725 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.

“CO2 flood” A tertiary recovery method in which CO2 is injected into a reservoir to enhance hydrocarbon recovery.

“completion” The installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“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, 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. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

“extension well” A well drilled to extend the limits of a known 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.

"LIBOR" London interbank offered rate.

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

"MBbl/d" One MBbl per day.

"MBOE" One thousand BOE.

"MBOE/d" One MBOE per day.

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

"MMBbl" One million Bbl.

"MMBOE" One million BOE.

"MMBtu" One million British Thermal Units.

"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 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 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:

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a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and
b. The project has been approved for development by all necessary parties and entities, including governmental entities.

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

"proved undeveloped reserves" or "PUDs" Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates of proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

"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.

"recompletion" An operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore.

"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.

“royalty interest” An interest in an oil or natural gas property entitling the owner to shares of the crude oil or natural gas production free of costs of exploration, development and production operations.

“SEC” The United States Securities and Exchange Commission.

“service well” A service well is a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane, CO_2 or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation or injection for in-situ combustion.

“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)

	June 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 60,154	$ 78,100
Accounts receivable trade, net	454,506	543,172
Derivative assets	32,076	135,577
Prepaid expenses and other	50,598	86,150
Total current assets	597,334	842,999
Property and equipment:		
Oil and gas properties, successful efforts method	15,698,099	14,949,702
Other property and equipment	292,125	276,582
Total property and equipment	15,990,224	15,226,284
Less accumulated depreciation, depletion and amortization	(3,388,964)	(3,083,572)
Total property and equipment, net	12,601,260	12,142,712
Goodwill	875,676	875,676
Debt issuance costs	80,058	53,274
Other long-term assets	59,594	104,843
TOTAL ASSETS	$ 14,213,922	$ 14,019,504
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 89,557	$ 62,664
Accrued capital expenditures	189,404	429,970
Revenues and royalties payable	223,871	254,018
Current portion of Production Participation Plan liability	-	113,391
Accrued liabilities and other	148,343	169,193
Taxes payable	65,019	63,822
Accrued interest	67,791	67,913
Deferred income taxes	18,886	47,545

Total current liabilities	802,871	1,208,516
Long-term debt	5,245,354	5,628,782
Deferred income taxes	1,216,022	1,230,630
Asset retirement obligations	146,079	167,741
Deferred gain on sale	55,453	60,305
Other long-term liabilities	40,312	20,486
Total liabilities	7,506,091	8,316,460
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 300,000,000 shares authorized; 206,472,261 issued and 204,142,725 outstanding as of June 30, 2015 and 168,346,020 issued and 166,889,152 outstanding as of December 31, 2014	206	168
Additional paid-in capital	4,645,266	3,385,094
Retained earnings	2,054,327	2,309,712
Total Whiting shareholders' equity	6,699,799	5,694,974
Noncontrolling interest	8,032	8,070
Total equity	6,707,831	5,703,044
TOTAL LIABILITIES AND EQUITY	$ 14,213,922	$ 14,019,504

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF INCOME (unaudited)

(in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
REVENUES AND OTHER INCOME:				
Oil, NGL and natural gas sales	$ 650,527	$ 825,760	$ 1,170,375	$ 1,547,010
Gain (loss) on sale of properties	(64,776)	1,796	(61,578)	12,355
Amortization of deferred gain on sale	3,738	7,473	9,574	15,217
Interest income and other	520	593	870	1,289
Total revenues and other income	590,009	835,622	1,119,241	1,575,871
COSTS AND EXPENSES:				
Lease operating	143,375	118,361	309,740	233,147
Production taxes	56,729	68,857	101,107	128,887
Depreciation, depletion and amortization	322,411	268,509	605,930	503,774
Exploration and impairment	57,557	31,512	138,481	73,619
General and administrative	44,987	35,555	88,967	67,889
Interest expense	89,176	39,045	163,433	81,189
Loss on early extinguishment of debt	45	-	5,634	-
Change in Production Participation Plan liability	-	(3,636)	-	-
Commodity derivative loss, net	102,419	26,076	92,568	50,611
Total costs and expenses	816,699	584,279	1,505,860	1,139,116
INCOME (LOSS) BEFORE INCOME TAXES	(226,690)	251,343	(386,619)	436,755
INCOME TAX EXPENSE (BENEFIT):				
Current	(84)	7,355	65	8,355
Deferred	(77,311)	92,562	(131,261)	167,923
Total income tax expense (benefit)	(77,395)	99,917	(131,196)	176,278
NET INCOME (LOSS)	(149,295)	151,426	(255,423)	260,477
Net loss attributable to noncontrolling interests	21	18	38	36

NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ (149,274)	$ 151,444	$ (255,385)	$ 260,513
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ (0.73)	$ 1.27	$ (1.37)	$ 2.19
Diluted	$ (0.73)	$ 1.26	$ (1.37)	$ 2.17
WEIGHTED AVERAGE SHARES OUTSTANDING:				
Basic	204,130	118,968	186,657	118,946
Diluted	204,130	120,027	186,657	120,045

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(in thousands)

	Six Months Ended June 30,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (255,423)	$ 260,477
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	605,930	503,774
Deferred income tax expense (benefit)	(131,261)	167,923
Amortization of debt issuance costs, debt discount and debt premium	19,828	7,342
Stock-based compensation	13,481	11,046
Amortization of deferred gain on sale	(9,574)	(15,217)
(Gain) loss on sale of properties	61,578	(12,355)
Undeveloped leasehold and oil and gas property impairments	51,553	36,031
Exploratory dry hole costs	799	3,622
Loss on early extinguishment of debt	5,634	-
Non-cash portion of derivative losses	184,395	44,744
Other, net	(3,130)	(3,205)
Changes in current assets and liabilities:		
Accounts receivable trade, net	88,666	(123,297)
Prepaid expense and other	35,245	(13,633)
Accounts payable trade and accrued liabilities	(110,635)	(10,628)
Revenues and royalties payable	(30,147)	15,589
Taxes payable	1,197	19,453
Net cash provided by operating activities	528,136	891,666
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and development capital expenditures	(1,727,396)	(1,326,080)
Acquisition of oil and gas properties	(20,402)	(44,519)
Other property and equipment	(8,727)	(34,675)
Proceeds from sale of oil and gas properties	311,628	83,152
Net cash used in investing activities	(1,444,897)	(1,322,122)
CASH FLOWS FROM FINANCING ACTIVITIES:		
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)	-

Borrowings under credit agreement	2,000,000	100,000
Repayments of borrowings under credit agreement	(3,400,000)	(100,000)
Repayment of tax sharing liability	-	(26,373)
Debt and equity issuance costs	(54,295)	(4,461)
Restricted stock used for tax withholdings	(1,111)	(11,340)
Proceeds from stock options exercised	3,048	253
Net cash provided by (used in) financing activities	898,815	(41,921)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(17,946)	(472,377)
CASH AND CASH EQUIVALENTS:		
Beginning of period	78,100	699,460
End of period	$ 60,154	$ 227,083
NONCASH INVESTING ACTIVITIES:		
Accrued capital expenditures related to property additions	$ 189,404	$ 216,076

See notes to consolidated financial statements.

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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	Total Whiting Shareholders' Equity	Noncontrolling Interest	Total Equity
BALANCES-January 1, 2014	120,102	$ 120	$ 1,583,542	$ 2,244,905	$ 3,828,567	$ 8,132	$ 3,836,699
Net income (loss)	-	-	-	260,513	260,513	(36)	260,477
Exercise of stock options	5	-	253	-	253	-	253
Restricted stock issued	908	1	(1)	-	-	-	-
Restricted stock forfeited	(381)	(1)	1	-	-	-	-
Restricted stock used for tax withholdings	(191)	-	(11,340)	-	(11,340)	-	(11,340)
Stock-based compensation	-	-	11,046	-	11,046	-	11,046
BALANCES-June 30, 2014	120,443	$ 120	$ 1,583,501	$ 2,505,418	$ 4,089,039	$ 8,096	$ 4,097,135
BALANCES-January 1, 2015	168,346	$ 168	$ 3,385,094	$ 2,309,712	$ 5,694,974	$ 8,070	$ 5,703,044
Net loss	-	-	-	(255,385)	(255,385)	(38)	(255,423)
Issuance of common stock	37,000	37	1,100,000	-	1,100,037	-	1,100,037
Equity component of Convertible Senior Notes, net	-	-	144,755	-	144,755	-	144,755
Exercise of stock options	149	-	3,048	-	3,048	-	3,048
Restricted stock issued	1,209	1	(1)	-	-	-	-
Restricted stock forfeited	(194)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(38)	-	(1,111)	-	(1,111)	-	(1,111)
Stock-based compensation	-	-	13,481	-	13,481	-	13,481
BALANCES-June 30, 2015	206,472	$ 206	$ 4,645,266	$ 2,054,327	$ 6,699,799	$ 8,032	$ 6,707,831

See notes to consolidated financial statements.

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 exploration, development, acquisition and production of crude oil, NGLs and natural gas primarily in the Rocky Mountains and Permian Basin regions 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, its consolidated subsidiaries and Whiting's pro rata share of the accounts of Whiting USA Trust I ("Trust I") pursuant to Whiting's 15.8% ownership interest in Trust I. On January 28, 2015, the net profits interest that Whiting conveyed to Trust I terminated as a result of 9.11 MMBOE (which amount is equivalent to 8.20 MMBOE attributable to the 90% net profits interest) having been produced and sold from the underlying properties. Upon termination, the net profits interest in the underlying properties reverted back to Whiting. 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 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 2014 Annual Report on Form 10-K. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in the Company's 2014 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 unvested restricted stock awards, outstanding stock options and contingently issuable shares of convertible debt, all using the treasury stock method. In the computation of diluted earnings per share, excess tax benefits that would be created upon the assumed vesting of unvested restricted shares or the assumed exercise of stock options (i.e. hypothetical excess tax benefits) are included in the assumed proceeds component of the treasury stock method to the extent that such excess tax benefits are more likely than not to be realized. In addition, to the extent the conversion value of the convertible debt exceeds the aggregate principal amount of the notes, such conversion spread is included in the diluted earnings per share computation under the treasury stock method. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

2. OIL AND GAS PROPERTIES

Net capitalized costs related to the Company's oil and gas producing activities at June 30, 2015 and December 31, 2014 are as follows (in thousands):

	June 30, 2015	December 31, 2014
Proved leasehold costs	$ 3,541,574	$ 3,637,026
Unproved leasehold costs	974,256	1,232,040
Costs of completed wells and facilities	10,645,009	9,319,808
Wells and facilities in progress	537,260	760,828
Total oil and gas properties, successful efforts method	15,698,099	14,949,702
Accumulated depletion	(3,303,361)	(3,003,270)
Oil and gas properties, net	$ 12,394,738	$ 11,946,432

3. ACQUISITIONS AND DIVESTITURES

2015 Acquisitions

There were no significant acquisitions during the six months ended June 30, 2015.

2015 Divestitures

In June 2015, the Company completed the sale of its interests in certain producing oil and gas wells, effective June 1, 2015, for a total purchase price of $185 million (subject to post-closing adjustments) and resulting in a pre-tax loss on sale of $95 million. The properties included over 2,000 gross wells in 134 fields across 10 states.

In April 2015, the Company completed the sale of its interests in certain producing oil and gas wells, effective May 1, 2015, for a purchase price of $108 million (subject to post-closing adjustments) and resulting in a pre-tax gain on sale of $31 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.

2014 Acquisitions

On December 8, 2014, the Company completed the acquisition of Kodiak Oil & Gas Corp. (now known as Whiting Canadian Holding Company ULC, "Kodiak"), whereby Whiting acquired all of the outstanding common stock of Kodiak (the "Kodiak Acquisition"). Pursuant to the terms of the Kodiak Acquisition agreement, Kodiak shareholders received 0.177 of a share of Whiting common stock in exchange for each share of Kodiak common stock they owned. Total consideration for the Kodiak Acquisition was $1.8 billion, consisting of 47,546,139 Whiting common shares issued at the market price of $37.25 per share on the date of issuance plus the fair value of Kodiak's outstanding equity awards assumed by Whiting. The aggregate purchase price of the transaction was $4.3 billion, which included the assumption of Kodiak's outstanding debt of $2.5 billion as of December 8, 2014 and the net cash acquired of $19 million.

Kodiak was an independent energy company focused on exploration and production of crude oil and natural gas reserves, primarily in the Williston Basin region of the United States. As a result of the Kodiak Acquisition, Whiting acquired approximately 327,000 gross (178,000 net) acres located primarily in North Dakota, including interests in 778 producing oil and gas wells and undeveloped acreage. Approximately 10,000 of the net acres acquired were located in Wyoming and Colorado.

The Kodiak Acquisition was accounted for using the acquisition method of accounting for business combinations. The allocation of the purchase price is based upon management's estimates and assumptions related to the fair value of assets acquired and liabilities assumed on the acquisition date using currently available information. Transaction costs relating to the Kodiak Acquisition were expensed as incurred. The initial accounting for the Kodiak Acquisition is preliminary, and adjustments to provisional amounts (such as goodwill, certain accrued receivables and liabilities, and their related deferred taxes) or recognition of additional assets acquired or liabilities assumed, may occur as additional information is obtained about facts and circumstances that existed as of the acquisition date.

The consideration transferred, preliminary fair value of assets acquired and liabilities assumed, and the resulting goodwill as of the acquisition date are as follows (in thousands):

Consideration:	
Fair value of Whiting's common stock issued (1)	$ 1,771,094
Fair value of Kodiak restricted stock units assumed by Whiting (2)	9,596
Fair value of Kodiak options assumed by Whiting	7,523
Total consideration	$ 1,788,213
Fair value of liabilities assumed:	
Accounts payable trade	$ 18,390
Accrued capital expenditures	104,509
Revenues and royalties payable	57,423
Accrued liabilities and other	45,695
Taxes payable	12,676
Accrued interest	18,070
Current deferred tax liability	30,279

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Long-term debt	2,500,875
Asset retirement obligations	8,646
Other long-term liabilities	15,735
Amount attributable to liabilities assumed	$ 2,812,298
Fair value of assets acquired:	
Cash and cash equivalents	$ 18,879
Accounts receivable trade, net	219,654
Derivative assets	85,718
Prepaid expenses and other	8,624
Oil and gas properties, successful efforts method:	
Proved properties	2,266,607
Unproved properties	1,000,396
Other property and equipment	11,347
Long-term deferred tax asset	107,497
Other long-term assets	6,113
Amount attributable to assets acquired	$ 3,724,835
Goodwill	$ 875,676

(1) 47,546,139 shares of Whiting common stock at $37.25 per share (closing price as of December 5, 2014) based on Kodiak’s 268,622,497 common shares outstanding at closing.
(2) 257,601 shares of Whiting common stock issued at $37.25 per share (closing price as of December 5, 2014) based on Kodiak’s 1,455,409 restricted stock units held by employees as of December 8, 2014.

Goodwill recognized as a result of the Kodiak Acquisition totaled $876 million, none of which is deductible for income tax purposes. Goodwill is primarily attributable to the operational and financial synergies expected to be realized from the acquisition, including the employment of optimized completion techniques on Kodiak's undrilled acreage which will improve hydrocarbon recovery, the realization of savings in drilling and well completion costs, the accelerated development of Kodiak’s asset base, and the acquisition of experienced oil and gas technical personnel.

2014 Divestitures

In March 2014, the Company completed the sale of approximately 49,900 gross (41,000 net) acres in its Big Tex prospect, which consisted mainly of undeveloped acreage as well as its interests in certain producing oil and gas wells, located in the Delaware Basin of Texas for a cash purchase price of $76 million resulting in a pre-tax gain on sale of $12 million.

4. LONG-TERM DEBT

Long-term debt consisted of the following at June 30, 2015 and December 31, 2014 (in thousands):

	June 30,	December 31,

	2015	2014
Credit agreement	$ -	$ 1,400,000
6.5% Senior Subordinated Notes due 2018	350,000	350,000
5% Senior Notes due 2019	1,100,000	1,100,000
8.125% Senior Notes due 2019, including unamortized debt premium of $21,663 and $23,742, respectively	819,213	823,742
1.25% Convertible Senior Notes due 2020, including unamortized debt discount of $226,699	1,023,301	-
5.75% Senior Notes due 2021, including unamortized debt premium of $2,840 and $3,180, respectively	1,202,840	1,203,180
5.5% Senior Notes due 2021, including unamortized debt premium of $867	-	350,867
5.5% Senior Notes due 2022, including unamortized debt premium of $993	-	400,993
6.25% Senior Notes due 2023	750,000	-
Total debt	$ 5,245,354	$ 5,628,782

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Credit Agreement—Whiting Oil and Gas, the Company's wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of June 30, 2015 had a borrowing base of $4.5 billion, with aggregate commitments of $3.5 billion. In April 2015, the Company entered into an amendment to its credit agreement to reaffirm the existing borrowing base in connection with the May 1, 2015 regular redetermination, as well as to modify certain financial covenants contained in the agreement. The Company may increase the maximum aggregate amount of commitments under the credit agreement up to the $4.5 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of June 30, 2015, the Company had $3.5 billion of available borrowing capacity, which was net of $5 million in letters of credit with no borrowings 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.

A portion of the revolving credit facility in an aggregate amount not to exceed $100 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 June 30, 2015, $95 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.

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

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of its lenders. Except for limited exceptions, the credit agreement also restricts the Company's ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the net assets of the subsidiaries. As of June 30, 2015, total restricted net assets were $6.5 billion, and there were no retained earnings free from restrictions. The credit agreement requires the Company, as of the last day of any quarter, (i) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) to not exceed a total senior secured debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 2.5 to 1.0 until the earlier of (a) January 1, 2017 or (b) the commencement of an investment-grade debt rating period as described below, and to not exceed a total debt to EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 thereafter. The Company was in compliance with its covenants under the credit agreement as of June 30, 2015.

Under the terms of the credit agreement, at any time during which Whiting has an investment-grade debt rating from Moody's Investors Service, Inc. or Standard & Poor's Ratings Group and Whiting has elected, at its discretion, to effect an investment-grade rating period, (i) certain security requirements, including the borrowing base requirement, and restrictive covenants will cease to apply, (ii) certain other restrictive covenants will become less restrictive, (iii) an additional financial covenant will be imposed, and (iv) the interest rate margin applicable to all revolving borrowings as well as the commitment fee with respect to the revolving facility will be based upon the Company's debt rating rather than the ratio of outstanding borrowings to the borrowing base.

The obligations of Whiting Oil and Gas under the credit agreement are secured by a first lien on substantially all of Whiting Oil and Gas' and Whiting Resource Corporation's properties included in the borrowing base for the credit agreement. 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”). The estimated fair value of these notes was $353 million and $345 million as of June 30, 2015 and December 31, 2014, respectively, based on quoted market prices for this debt security, and such fair value is therefore designated as Level 1 within the valuation hierarchy.

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 estimated fair value of the 2019 Senior Notes was $1.1 billion and $1.0 billion as of June 30, 2015 and December 31, 2014, respectively. The estimated fair value of the 2021 Senior Notes was $1.2 billion and $1.1 billion as of June 30, 2015 and December 31, 2014, respectively. These 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.

Kodiak Senior Notes. In conjunction with the Kodiak Acquisition, 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”). The Kodiak Notes were recorded at their fair values of $824 million, $351 million and $401 million, respectively, on December 8, 2014, the closing date of the acquisition.

Upon closing of the Kodiak Acquisition, the indentures under which the Kodiak Notes were issued (the “Kodiak Indentures”) were amended to (i) modify certain covenants and restrictions, (ii) provide for unconditional and irrevocable guarantees by Whiting Petroleum Corporation and Whiting Oil and Gas of the prompt payment, when due, of any amounts owed under the Kodiak Notes and the Kodiak Indentures, and (iii) allow Whiting US Holding Company to become a co-issuer of the Kodiak Notes. Also in conjunction with the Kodiak Acquisition, in December 2014, each of the indentures governing the Company’s 2019 Senior Notes, 2021 Senior Notes and 2018 Senior Subordinated Notes were amended to include Whiting US Holding Company, Kodiak and Whiting Resources Corporation as guarantors. Shortly after closing, the Kodiak Notes were deregistered in accordance with the Securities Exchange Act of 1934, and accordingly, the Company is exempt from the reporting requirements under Rule 3-10 of Regulation S-X of the SEC with respect to the Kodiak Notes.

Repurchase of Kodiak Notes. On January 7, 2015, as required under the Kodiak Indentures upon a change in control of Kodiak, Whiting offered to repurchase at 101% of par all $1,550 million principal amount of Kodiak Notes then outstanding. On March 6, 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. On May 1, 2015, Whiting paid $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. The Company financed the repurchases with borrowings under its revolving credit facility. As a result of the repurchases, Whiting recognized a $6 million loss on early extinguishment of debt, which consisted of an $8 million cash charge related to the redemption premium on the Kodiak Notes, partially offset by a $2 million non-cash credit related to the acceleration of unamortized debt premiums on such notes.

The remaining debt premium on the 2019 Kodiak Notes is being amortized as a reduction to interest expense over the life of the notes. The estimated fair value of the 2019 Kodiak Notes was $839 million and $812 million as of June 30, 2015 and December 31, 2014, respectively, based on quoted market prices for this debt security, and such fair value is therefore designated as Level 1 within the valuation hierarchy.

Issuance of Senior Notes. 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 “Whiting Senior Notes”). The Company used the net proceeds from this issuance to repay a portion of the debt outstanding under its credit agreement. The estimated fair value of the 2023 Senior Notes was $743 million as of June 30, 2015. The fair value is based on quoted market prices for this debt security, and such fair value is therefore designated as Level 1 within the valuation hierarchy.

Convertible Senior Notes—In March 2015, the Company issued at par $1,250 million of 1.25% Convertible Senior Notes due April 2020 (the “Convertible Senior Notes”) for net proceeds of $1.2 billion, net of initial purchasers’ fees of $25 million. The Company used the net proceeds from this issuance to repay a portion of the debt outstanding under its credit agreement. The notes will mature on April 1, 2020 unless earlier converted in accordance with their terms.

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 Convertible Senior Notes in cash upon conversion. Prior to January 1, 2020, the Convertible Senior Notes will be convertible only under the following circumstances: (i) during any calendar quarter commencing after the calendar quarter ending on June 30, 2015 (and only during such calendar quarter), if the last reported sale price of the Company's common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading price per $1,000 principal amount of the 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 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 Convertible Senior Notes in connection with such corporate event. As of June 30, 2015, none of the contingent conditions allowing holders of the Convertible Senior Notes to convert these notes had been met.

Upon issuance, the Company separately accounted for the liability and equity components of the 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 Convertible Senior Notes and the estimated fair value of the liability component was recorded as a debt discount and will be amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 5.61% per annum. The fair value of the 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 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 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 within debt issuance costs 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 Convertible Senior Notes consist of the following at June 30, 2015 (in thousands):

Liability component:	
Principal	$ 1,250,000
Less: note discount	(226,699)

Net carrying value	$ 1,023,301
Equity component (1)	$ 237,500

(1) Recorded in additional paid-in capital, net of $5 million of issuance costs and $88 million of deferred taxes.
The estimated fair value of the Convertible Senior Notes was $1.4 billion as of June 30, 2015. The fair value is based on quoted market prices for this debt security, and such fair value is therefore designated as Level 1 within the valuation hierarchy.

Interest expense recognized on the Convertible Senior Notes related to the stated interest rate and amortization of the debt discount totaled $14 million and $15 million for the three and six months ended June 30, 2015, respectively.

The Whiting Senior Notes and the Convertible Senior Notes are unsecured obligations of Whiting Petroleum Corporation and the 2019 Kodiak Notes are unsecured obligations of Whiting US Holding Company, 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 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, the Convertible Senior Notes, the 2019 Kodiak Notes and Whiting Oil and Gas' credit agreement.

The Company's obligations under the 2018 Senior Subordinated Notes, the Whiting Senior Notes and the Convertible Senior Notes are fully and unconditionally guaranteed by the Company's wholly-owned subsidiaries, Whiting Oil and Gas, Whiting US Holding

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Company, Whiting Canadian Holding Company ULC and Whiting Resources Corporation (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 June 30, 2015 and December 31, 2014 were $7 million and $12 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 six months ended June 30, 2015 (in thousands):

Asset retirement obligation at January 1, 2015	$ 179,931
Additional liability incurred	8,374
Revisions to estimated cash flows	3,165
Accretion expense	12,485
Obligations on sold properties	(50,968)
Liabilities settled	86
Asset retirement obligation at June 30, 2015	$ 153,073

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and Whiting uses derivative instruments to manage its commodity price risk. 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 seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. 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 acquisitions and drilling programs. The Company does not enter into derivative contracts for speculative or trading purposes.

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

The table below details the Company's costless collar and swap derivatives entered into to hedge forecasted crude oil production revenues as of July 1, 2015.

		Whiting Petroleum Corporation	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Three-way collars (1)	Jul - Dec 2015	8,700,000	$44.48 - $54.83 - $70.54
	Jan - Dec 2016	16,800,000	$43.75 - $53.75 - $74.40
Collars	Jul - Dec 2015	1,255,200	$51.06 - $57.37
	Jan - Dec 2016	3,000,000	$51.00 - $63.48
	Jan - Dec 2017	3,000,000	$53.00 - $70.44
Swaps	Jul - Dec 2015	1,531,170	$76.41
	Total	34,286,370	

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(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 requirement 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 June 30, 2015, the estimated fair value of this derivative contract was a liability of $8 million.

Embedded Commodity Derivative Contract—In May 2011, Whiting entered into a long-term contract to purchase CO_2 for use in its EOR project that is being carried out at its North Ward Estes field in Texas. This contract contained a price adjustment clause that was linked to changes in NYMEX crude oil prices. The Company had determined that the portion of this contract linked to NYMEX oil prices was not clearly and closely related to the host contract, and the Company therefore bifurcated this embedded pricing feature from its host contract and reflected it at fair value in the consolidated financial statements. This contract has been terminated.

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. The following table summarizes the effects of commodity derivative instruments on the consolidated statements of income for the three and six months ended June 30, 2015 and 2014 (in thousands):

Not Designated as ASC 815 Hedges	Income Statement Classification	Loss Recognized in Income Six Months Ended June 30, 2015	2014
Commodity contracts	Commodity derivative loss, net	$ 92,568	$ 27,491
Embedded commodity contracts	Commodity derivative loss, net	-	23,120
Total		$ 92,568	$ 50,611

Not Designated as		Loss Recognized in Income Three Months Ended June 30,

ASC 815 Hedges	Income Statement Classification	2015	2014
Commodity contracts	Commodity derivative loss, net	$ 102,419	$ 17,304
Embedded commodity contracts	Commodity derivative loss, net	-	8,772
Total		$ 102,419	$ 26,076

Offsetting of Derivative Assets and Liabilities. The Company typically has numerous hedge positions with each individual financial derivative counterparty that span a several-month time period and that typically result in both fair value asset and liability positions held with that counterparty. These positions are all offset to a single fair value asset or liability amount at the end of each reporting period. 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 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):

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Not Designated as ASC 815 Hedges	Balance Sheet Classification	June 30, 2015 (1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts - current	Derivative assets	$ 91,419	$ (59,343)	$ 32,076
Commodity contracts - non-current	Other long-term assets	52,155	(52,136)	19
Total derivative assets		$ 143,574	$ (111,479)	$ 32,095
Derivative liabilities:				
Commodity contracts - current	Accrued liabilities and other	$ 74,481	$ (59,343)	$ 15,138
Commodity contracts - non-current	Other long-term liabilities	72,453	(52,136)	20,317
Total derivative liabilities		$ 146,934	$ (111,479)	$ 35,455

Not Designated as ASC 815 Hedges	Balance Sheet Classification	December 31, 2014 (1) Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts - current	Derivative assets	$ 154,329	$ (18,752)	$ 135,577
Commodity contracts - non-current	Other long-term assets	45,459	-	45,459
Total derivative assets		$ 199,788	$ (18,752)	$ 181,036
Derivative liabilities:				
Commodity contracts - current	Accrued liabilities and other	$ 18,752	$ (18,752)	$ -
Total derivative liabilities		$ 18,752	$ (18,752)	$ -

(1) Because counterparties to the Company's financial derivative contracts 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 the tables above.

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

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 (including the Kodiak Notes), Convertible Senior Notes and Senior Subordinated Notes are recorded at cost, and the fair values of these instruments are included in the Long-Term Debt footnote. 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 counterparties, as appropriate.

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.

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· 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.

The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2015 and December 31, 2014, 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 June 30, 2015
Financial Assets				
Commodity derivatives – current	$ -	$ 32,076	$ -	$ 32,076
Commodity derivatives – non-current	-	19	-	19
Total financial assets	$ -	$ 32,095	$ -	$ 32,095
Financial Liabilities				
Commodity derivatives – current	$ -	$ 13,399	$ 1,739	$ 15,138
Commodity derivatives – non-current	-	14,515	5,802	20,317
Total financial liabilities	$ -	$ 27,914	$ 7,541	$ 35,455

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2014
Financial Assets				
Commodity derivatives – current	$ -	$ 127,506	$ 8,071	$ 135,577
Commodity derivatives – non-current	-	-	45,459	45,459
Total financial assets	$ -	$ 127,506	$ 53,530	$ 181,036

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the tables above:

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

In addition, the Company 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 did 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 included certain market differential metrics that were unobservable during the term of the contract. Such unobservable inputs were significant to the contract valuation methodology, and the contract's fair value was therefore designated as Level 3 within the valuation hierarchy.

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Embedded Commodity Derivatives. The Company had a long-term CO_2 purchase contract, which had a price adjustment clause linked to changes in NYMEX crude oil prices. Whiting determined that the portion of this contract linked to NYMEX oil prices was not clearly and closely related to its corresponding host contract, and the Company therefore bifurcated this embedded pricing feature from the host contract and reflected it at fair value in its consolidated financial statements. The assumptions used in the CO_2 contract valuation, which was based on the income approach, included certain oil price metrics that were unobservable during the term of the contract. Such unobservable oil price inputs were significant to the CO_2 contract valuation methodology, and the contract's fair value was therefore designated as Level 3 within the valuation hierarchy. The Company terminated this CO_2 purchase contract, and its embedded derivative had a fair value of zero as of December 31, 2014.

Level 3 Fair Value Measurements. A third-party valuation specialist is utilized to determine the fair value of the commodity 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.

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 six months ended June 30, 2015 and 2014 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Fair value asset, beginning of period	$ 35,786	$ 22,068	$ 53,530	$ 36,416
Unrealized losses on commodity derivative contracts included in earnings (1)	(43,327)	(8,772)	(61,071)	(23,120)
Transfers into (out of) Level 3	-	-	-	-
Fair value asset (liability), end of period	$ (7,541)	$ 13,296	$ (7,541)	$ 13,296

(1) Included in commodity derivative loss in the consolidated statements of income.

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

	Fair Value at June 30, 2015 (in thousands)	Valuation Technique	Unobservable Input	Amount (per Bbl)
Commodity derivative contract	($7,541)	Income approach	Market differential for crude oil	$5.18

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.

Nonrecurring Fair Value Measurements. The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including proved oil and gas property impairments.   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 oil and gas or CO_2 properties during the 2015 or 2014 reporting periods presented.

8. DEFERRED COMPENSATION

Production Participation Plan—The Company had a Production Participation Plan (the “Plan”) in which all employees participated. On June 11, 2014, the Board of Directors of the Company terminated the Plan effective December 31, 2013. Prior to Plan termination, interests in oil and gas properties acquired, developed or sold during the year were allocated to the Plan on an annual basis as determined by the Compensation Committee of the Company’s Board of Directors. Once allocated, the interests (not legally conveyed) were fixed. Interest allocations prior to 1995 consisted of 2%   3% overriding royalty interests. Interest allocations after 1995 were 1.75%   5% of oil and gas sales less lease operating expenses and production taxes.

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Employees vested in the Plan ratably at 20% per year over a five-year period. However, pursuant to the terms of the Plan, upon Plan termination all employees fully vested, and the Company was required to distribute to each Plan participant an amount, based upon the valuation method set forth in the Plan, in a lump sum payment twelve months after the date of termination. This distribution included the value of proved undeveloped oil and gas properties awarded upon Plan termination and was based on forecasted commodity prices for crude oil, NGLs and natural gas as of December 31, 2013. In January 2015, a portion of the amount due to Plan participants representing a regular distribution under the Plan was paid totaling $41 million, and in June 2015, the remaining fully vested amount due to Plan participants was paid totaling $72 million.

Accrued compensation expense under the Plan for the six months ended June 30, 2014 primarily related to the change in liability for employee vestings and PUDs assigned upon Plan termination and amounted to $24 million charged to general and administrative expense and $2 million charged to exploration expense.

Prior to Plan termination, the Company recorded non-cash changes in the present value of estimated future payments under the Plan as a separate line item in the consolidated statements of income.

9. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

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. The Company used the net proceeds from these offerings to repay a portion of the debt outstanding under its credit agreement, as well as for general corporate purposes.

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 includes 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 will be available for future issuance under the 2013 Equity Plan. Under the 2013 Equity Plan, no employee or officer participant may be granted options for more than 600,000 shares of common stock, stock appreciation rights relating to more than 600,000 shares of common stock, or more than 300,000 shares of restricted stock during any calendar year. 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. As of June 30, 2015, 4,079,054 shares of common stock remained available for grant under the 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):

	Six Months Ended June 30,	
	2015	2014
Balance at January 1	$ 8,070	$ 8,132
Net loss	(38)	(36)
Balance at June 30	$ 8,032	$ 8,096

10. 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 six months ended June 30, 2015 and 2014 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.

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.

11. EARNINGS PER SHARE

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Basic Earnings (Loss) Per Share				
Numerator:				
Net income (loss) available to common shareholders, basic	$ (149,274)	$ 151,444	$ (255,385)	$ 260,513
Denominator:				
Weighted average shares outstanding, basic	204,130	118,968	186,657	118,946
Diluted Earnings (Loss) Per Share				
Numerator:				
Net income (loss) available to common shareholders, diluted	$ (149,274)	$ 151,444	$ (255,385)	$ 260,513
Denominator:				
Weighted average shares outstanding, basic	204,130	118,968	186,657	118,946
Restricted stock and stock options	-	1,059	-	1,099
Weighted average shares outstanding, diluted	204,130	120,027	186,657	120,045
Earnings (loss) per common share, basic	$ (0.73)	$ 1.27	$ (1.37)	$ 2.19
Earnings (loss) per common share, diluted	$ (0.73)	$ 1.26	$ (1.37)	$ 2.17

During the three months ended June 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 406,986 shares of restricted stock and 96,767 stock options. In addition, the diluted earnings per share calculation for the three months ended June 30, 2015 excludes (i) the dilutive effect of 764,827 incremental shares of restricted stock that did not meet its market-based vesting criteria as of June 30, 2015 and (ii) the anti-dilutive effect of 251,040 common shares for stock options that were out-of-the-money.

During the six months ended June 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 479,975 shares of restricted stock and 107,286 stock options. In addition, the diluted earnings per share calculation for the six months ended June 30, 2015 excludes (i) the dilutive effect of 756,376 incremental shares of restricted stock that did not meet its market-based vesting criteria as of June 30, 2015 and (ii) the anti-dilutive effect of 287,382 common shares for stock options that were out-of-the-money.

As discussed in the Long-Term Debt footnote, the Company has Convertible Senior Notes whereby it has the option to settle the conversion of such notes with cash, shares of common stock or any combination thereof. The Company's intent is to settle the principal amount of the Convertible Senior 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 June 30, 2015, the conversion value did not exceed the principal amount of the notes, and accordingly, there was no impact to diluted earnings per share for that period.

12. COMMITMENTS AND CONTINGENCIES

Delivery Commitments—In the second quarter of 2015, the Company entered into a physical delivery contract requiring the Company to deliver fixed volumes of crude oil from its Sanish field in Mountrail County, North Dakota. Under the terms of the contract, the Company is committed to deliver 5.5 MMBbl of crude oil per year for a term of seven years beginning when the related pipeline is placed in service, which is expected to occur in the second half of 2016. If the Company fails to deliver the committed volumes, it will be required to pay a deficiency payment of $7.00 per undelivered Bbl (or up to $38 million per year), subject to upward adjustment, over the duration of the contract. However, the Company expects to fully deliver the contracted volumes and therefore avoid any payments for deficiencies.

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Drilling Rig Contracts—As of June 30, 2015, the Company had 11 drilling rigs under long-term contract, all of which were operating in the Rocky Mountains region. As of June 30, 2015, the Company's minimum future payments under these contracts totaled $52 million for the remainder of 2015, $91 million in 2016 and $33 million in 2017. Subsequent to June 30, 2015, the Company provided notice to its counterparties to three of these long-term drilling contracts of the Company's intent to early terminate such contracts on or around September 1, 2015. The Company expects to incur early termination penalties totaling approximately $26 million, which would be in lieu of paying the remaining drilling commitments under these contracts of $27 million. Of the remaining eight long-term contracts, two expire in 2016 and six in 2017. As of June 30, 2015, early termination of the remaining eight contracts would require termination penalties of $123 million, which would be in lieu of paying the remaining drilling commitments under these contracts.

13. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In July 2015, the FASB issued Accounting Standards Update No. 2015-11, Simplifying the Measurement of Inventory ("ASU 2015-11"). This ASU requires entities to measure most inventory at the lower of cost and net realizable value, thereby simplifying the current guidance under which an entity must measure inventory at the lower of cost or market. ASU 2015-11 is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years and should be applied prospectively. Early adoption is permitted. The adoption of this standard will not have a material impact on the Company's consolidated financial statements.

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). The objective of ASU 2015-03 is to simplify the presentation of debt issuance costs in financial statements by presenting such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. ASU 2015-03 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015 and should be applied retrospectively. Early adoption is permitted. The adoption of this standard will not have an impact on the Company's consolidated financial statements, other than balance sheet reclassifications.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15, Presentation of Financial Statements – Going Concern ("ASU 2014-15"). The objective of ASU 2014-15 is to provide guidance on management's responsibility to evaluate whether there is substantial doubt about a company's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for fiscal years ending after December 15, 2016, and annual and interim periods thereafter. This standard is not expected to have an impact on the Company's consolidated financial statements.

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. ASU 2014 09 is currently effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. However, the FASB recently announced plans to defer the effective date of ASU 2014-09 for one year. The Company is currently evaluating the impact of adopting ASU 2014 09, but the standard is not expected to have a significant effect on its consolidated financial statements.

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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 exploration, development, acquisition and production activities primarily in the Rocky Mountains and Permian Basin regions 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 successes and production growth, while continuing to selectively pursue acquisitions that complement our existing core properties, such as the acquisition of Kodiak (the "Kodiak Acquisition"). We believe the combination of acquisitions, subsequent development and organic drilling provides us with a broad set of growth alternatives and allows us to direct our capital resources to what we consider to be the most advantageous investments. We also believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. Our growth plan is centered on the following activities:

- pursuing the development of projects that we believe will generate attractive rates of return;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows;
- allocating a portion of our exploration and development budget to leasing and exploring prospect areas; and
- seeking property acquisitions that complement our core areas, such as the Kodiak Acquisition.

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that established a presence in a new area of interest or that have complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. In addition, our willingness to acquire non-operated properties in new geographic regions provides us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis.

We continually evaluate our current property portfolio and sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own, such as the asset sales discussed below under Acquisition and Divestiture Highlights. We are currently exploring additional asset sales of non-core properties and anticipate further sales by the end of 2015.

Our revenue, profitability and future growth rate depend on many factors which are beyond our control, such 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 our Annual Report on Form 10-K for the period ended December 31, 2014. 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 2013:

	2013				2014				2015	
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
Crude oil	$ 94.34	$ 94.23	$ 105.82	$ 97.50	$ 98.62	$ 102.98	$ 97.21	$ 73.12	$ 48.57	$ 57.96
Natural gas	$ 3.34	$ 4.10	$ 3.58	$ 3.60	$ 4.93	$ 4.68	$ 4.07	$ 4.04	$ 2.99	$ 2.61

Oil prices have fallen significantly since reaching highs of over $105.00 per Bbl in June 2014, dropping below $45.00 per Bbl in March 2015. Natural gas prices have also declined from over $4.80 per Mcf in April 2014 to below $2.50 per Mcf in April 2015. In addition, forecasted prices for both oil and gas for the remainder of 2015 have also declined. 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 reserves. A substantial or extended decline in oil, NGL or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. Lower oil, NGL and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders and which 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. In addition, higher oil and natural gas prices may result in significant mark-to-market losses being incurred on our commodity-based derivatives, which may in turn cause us to experience net losses.

2015 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 135.8 MBOE/d for the second quarter of 2015, which represents a 2% increase from 133.5 MBOE/d in the first quarter of 2015. As of June 30, 2015, we had seven rigs active in the Williston Basin. We have implemented our new completion design across our acreage in the Williston Basin, utilizing cemented liners, plug-and-perf technology and higher sand volumes with both hybrid and slickwater fracture stimulation methods, resulting 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.

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 June 30, 2015, the plant was processing over 23 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 second quarter of 2015, net production from the Redtail field averaged 17.1 MBOE/d, representing a 31% increase from 13.0 MBOE/d in the first quarter of 2015. We have established production in the Niobrara “A”, “B” and “C” zones and the Codell/Fort Hays formations, and we began testing our new slickwater fracture stimulation method in this field in 2015. 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. We are currently testing a 32-well per spacing unit pattern in the Niobrara “A”, “B” and “C” zones. Additionally, the Codell/Fort Hays formation is prospective throughout our acreage in the Redtail field, and we are currently expanding our drilling program in that formation. As of June 30, 2015, we had one drilling rig operating in this area.

In April 2014, we brought online the Redtail gas plant to process the associated gas produced from our wells in this area. The plant’s current inlet capacity is 20 MMcf/d, and we plan to further expand the plant’s capacity to 50 MMcf/d in the third quarter of 2015 and to 70 MMcf/d in the first half of 2016.

Permian Basin

At our North Ward Estes field in the Ward and Winkler counties in Texas, we continue to have significant development and related infrastructure activity since we acquired it in 2005. Our activity at North Ward Estes to date has resulted in production increases and substantial reserve additions, and our expansion of the CO_2 flood in this area continues to generate positive results.

North Ward Estes has responded positively to the water and CO_2 floods that we initiated in May 2007. Net production from North Ward Estes averaged 9.4 MBOE/d for the second quarter of 2015, representing a slight decrease from 9.5 MBOE/d in the first quarter of 2015. We are currently injecting CO_2 into one of the largest phases of our eight-phase project at North Ward Estes. As of June 30, 2015, we were injecting approximately 405 MMcf/d of CO_2 into the field, over half of which is recycled.

Other Non-Core Properties

Whiting USA Trust I. On January 28, 2015, the net profits interest that Whiting conveyed to Whiting USA Trust I ("Trust I") terminated as a result of 9.11 MMBOE (which amount is equivalent to 8.20 MMBOE attributable to the 90% net profits interest) having been produced and sold from the underlying properties. Upon termination, the net profits interest in the underlying properties reverted back to Whiting, resulting in an increase in our production volumes of approximately 2.3 MBOE/d as of the termination of the net profits interest. However, these properties were sold effective May 1, 2015, as discussed below under "Acquisition and Divestiture Highlights."

Acquisition and Divestiture Highlights.

In June 2015, we completed the sale of our interests in certain producing oil and gas wells, effective June 1, 2015, for a purchase price of $185 million (subject to post-closing adjustments) and resulting in a loss on sale of $95 million. The properties included over 2,000 gross wells in 134 fields across 10 states. The properties had estimated proved reserves of 23.7 MMBOE as of December 31, 2014, representing 3% of our proved reserves as of that date, and generated 6.0 MBOE/d (or 4%) of our May 2015 average daily production.

In April 2015, we completed the sale of our interests in certain producing oil and gas wells, effective May 1, 2015, for a cash purchase price of $108 million (subject to post-closing adjustments) and resulting in a pre-tax gain on sale of $31 million. The properties are located in 187 fields across 14 states, and predominately consisted of assets that were previously included in the underlying properties of Whiting USA Trust I. The properties had estimated proved reserves of 8.9 MMBOE as of December 31, 2014, representing 1% of our total proved reserves as of that date, and generated 2.7 MBOE/d (or 2%) of our March 2015 average daily net production.

Financing Highlights.

In March 2015, we completed a public offering of our 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, we 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. Concurrent with the common stock offering in March, we issued at par $1,250 million of 1.25% Convertible Senior Notes due April 2020 (the "Convertible Senior Notes"). The notes will mature on April 1, 2020 unless earlier converted in accordance with their terms. In addition, we issued at par $750 million of 6.25% Senior Notes due April 2023. We used the net proceeds from these offerings to repay all of the debt outstanding under our credit agreement, as well as for general corporate purposes.

On January 7, 2015, as required under the terms of the indentures governing the Kodiak Notes (the "Kodiak Indentures") upon a change in control of Kodiak, we offered to repurchase at 101% of par all $800 million principal amount of the 8.125% Senior Notes due December 2019 (the "2019 Kodiak Notes"), $350 million principal amount of the 5.5% Senior Notes due 2021 (the "2021 Kodiak Notes") and $400 million principal amount of the 5.5% Senior Notes due 2022 (the "2022 Kodiak Notes" and together with the 2019 Kodiak Notes and the 2021 Kodiak Notes, the "Kodiak Notes"). On March 6, 2015, we 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. On May 1, 2015, we paid $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. We financed the repurchases with borrowings under our revolving credit facility, which were subsequently repaid with proceeds from the equity and debt offerings discussed above, and with cash on hand. As a result of the repurchases, we recognized a $6 million loss on early extinguishment of debt, which consisted of an $8 million cash charge related to the redemption premium on the Kodiak Notes, partially offset by a $2 million non-cash credit related to the acceleration of unamortized debt premiums on such notes.

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Results of Operations

Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

	Six Months Ended June 30,	
	2015	2014
Net production:		
Oil (MMBbl)	24.6	15.3
NGLs (MMBbl)	2.4	1.4
Natural gas (Bcf)	21.0	13.9
Total production (MMBOE)	30.5	19.0
Net sales (in millions):		
Oil (1)	$ 1,086.4	$ 1,388.5
NGLs	36.5	65.2
Natural gas	47.5	93.3
Total oil, NGL and natural gas sales	$ 1,170.4	$ 1,547.0
Average sales prices:		
Oil (per Bbl) (1)	$ 44.15	$ 91.04
Effect of oil hedges on average price (per Bbl)	3.73	(0.38)
Oil net of hedging (per Bbl)	$ 47.88	$ 90.66
Weighted average NYMEX price (per Bbl) (2)	$ 53.31	$ 100.96
NGLs (per Bbl)	$ 15.13	$ 45.47
Natural gas (per Mcf)	$ 2.26	$ 6.73
Weighted average NYMEX price (per Mcf) (2)	$ 2.79	$ 4.80
Costs and expenses (per BOE):		
Lease operating expenses	$ 10.15	$ 12.27
Production taxes	$ 3.31	$ 6.79
Depreciation, depletion and amortization	$ 19.86	$ 26.52
General and administrative	$ 2.92	$ 3.57

(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 $377 million to $1.2 billion when comparing the first half of 2015 to the same period in 2014. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 61%, our NGL sales volumes increased 68% and our natural gas sales volumes increased 52% between periods. The oil volume increase between periods resulted primarily from producing properties acquired in the Kodiak Acquisition, as well as drilling success at our Hidden Bench/Tarpon, Redtail, and Missouri Breaks fields. The Kodiak Acquisition, which closed on December 8, 2014, added 6,105 MBbl of oil production during the first half of 2015 across several of our Northern Rockies areas. In addition, oil production from our Hidden Bench/Tarpon fields increased 1,235 MBbl, Redtail field increased

1,195 MBbl and our Missouri Breaks field increased 955 MBbl over the same period in 2014 as a result of drilling. These production increases were partially offset by normal field production decline across several of our areas. Our NGLs are generally produced concurrently with our crude oil volumes, resulting in a high correlation between fluctuations in our oil quantities sold and our NGL quantities sold. As a result, our NGL sales volume increases generally related to the same areas as our oil volume increases, such as our Hidden Bench/Tarpon fields and our Redtail field, as well as NGL production added from the Kodiak Acquisition. The gas volume increase between periods was primarily the result of new wells drilled and completed during the past twelve months, which caused increases in associated gas production of 1,690 MMcf at our Redtail field, 1,170 MMcf at our Hidden Bench/Tarpon fields, 970 MMcf at our Sanish and Parshall fields and 325 MMcf at our Cassandra field. In addition, 4,015 MMcf of gas production was added as a result of the Kodiak Acquisition. These gas volume increases were partially offset by the divestitures discussed above under "Acquisition and Divestiture Highlights," as well as normal field production decline across several of our areas. The property divestitures in April and June of 2015 negatively impacted gas production by 860 MMcf during the first half of 2015.

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These crude oil, NGL and natural gas production-related increases in net revenue were offset by decreases in the average sales price realized for oil, NGLs and natural gas in the first half of 2015 compared to 2014. Our average price for oil before the effects of hedging decreased 52%, our average sales price for NGLs decreased 67% and our average sales price for natural gas decreased 66% between periods.

Gain (Loss) on Sale of Properties. During the first half of 2015, we sold our interests in certain producing oil and gas wells for an aggregate purchase price of $293 million, which resulted in a pre-tax loss on sale of $65 million. During the first half of 2014, we sold undeveloped acreage as well as our interests in certain producing oil and gas wells in the Big Tex prospect for net proceeds of $76 million in cash, which resulted in a pre-tax gain on sale of $12 million. There were no other property divestitures resulting in a significant gain or loss on sale during the first half of 2015 or 2014.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during the first half of 2015 were $310 million, a $77 million increase over the same period in 2014. Higher LOE in 2015 were primarily related to an $82 million increase in oil field goods and services associated with net wells we added during the last twelve months as a result of the Kodiak Acquisition and through drilling, partially offset by the impact of our property divestitures in the first half of 2015 as well as a decrease in well workover activity between periods. Workovers decreased from $34 million in the first half of 2014 to $29 million in the first half of 2015, primarily due to a reduction in well workover activity at our CO2 project at North Ward Estes.

Our lease operating expenses on a BOE basis, however, decreased when comparing the first half of 2015 to the same 2014 period. LOE per BOE amounted to $10.15 during the first half of 2015, which represents a decrease of $2.12 per BOE (or 17%) from the first half of 2014. This decrease was mainly due to declining costs of goods and services in the industry combined with higher overall production volumes between periods, lower well workover costs and the impact of property divestitures discussed above. The properties sold during the first half of 2015 consisted mainly of mature oil and gas producing properties with LOE per BOE rates that were higher than our overall rate.

Production Taxes. Our production taxes during the first half of 2015 were $101 million, a $28 million decrease over the same period in 2014, 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 8.6% and 8.3% for the first half of 2015 and 2014, respectively.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense increased $102 million in 2015 as compared to the first half of 2014. The components of our DD&A expense were as follows (in thousands):

	Six Months Ended June 30,	
	2015	2014
Depletion	$ 589,051	$ 494,738
Depreciation	4,394	2,493
Accretion of asset retirement obligations	12,485	6,543

Total	$ 605,930	$ 503,774

DD&A for the first half of 2015 increased over the same period in 2014 primarily due to $94 million in higher depletion expense between periods. Of this increase, $222 million related to an increase in our overall production volumes during the first half of 2015 which was partially offset by a $128 million decrease related to a lower depletion rate between periods. On a BOE basis, our overall DD&A rate of $19.86 for the first half of 2015 was 25% lower than the rate of $26.52 for the same period in 2014. The primary factors contributing to this lower DD&A rate were additions to proved and proved developed reserves over the last twelve months, including reserves that were added as a result of the Kodiak Acquisition, as well as impairment write-downs on proved oil and gas properties recognized in the fourth quarter of 2014. The positive impact of these factors was partially offset by $3.2 billion in drilling and development expenditures during the past twelve months.

Exploration and Impairment Costs. Our exploration and impairment costs increased $65 million for the first half of 2015 as compared to the same period in 2014. The components of our exploration and impairment costs were as follows (in thousands):

	Six Months Ended June 30,	
	2015	2014
Exploration	$ 86,928	$ 37,588
Impairment	51,553	36,031
Total	$ 138,481	$ 73,619

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Exploration costs increased $49 million during the first half of 2015 as compared to the same period in 2014 primarily due to rig termination fees of $65 million incurred in 2015, partially offset by decreases in geological and geophysical (“G&G”) activity and lower exploratory dry hole costs between periods. G&G costs, such as seismic studies, amounted to $5 million during the first half of 2015 as compared to $18 million during the first six months of 2014. We did not drill any exploratory dry holes during the first half of 2015, while we drilled one exploratory dry hole in the Rocky Mountains region totaling $4 million during the first half of 2014.

Impairment expense for the first half of 2015 and 2014 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $50 million during the first half of 2015 as compared to $36 million for the first half of 2014. This increase in impairment expense in 2015 is due to $1.0 billion in unproved property costs added as a result of the Kodiak Acquisition.

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

	Six Months Ended June 30, 2015	2014
General and administrative expenses	$ 162,688	$ 126,451
Reimbursements and allocations	(73,721)	(58,562)
General and administrative expenses, net	$ 88,967	$ 67,889

G&A expense before reimbursements and allocations increased $36 million during the first half of 2015 as compared to the same period in 2014 primarily due to higher employee compensation between periods. Employee compensation increased $25 million for the first half of 2015 as compared to the same period in 2014 due to personnel hired during the past twelve months, primarily related to the Kodiak Acquisition, as well as general pay increases.

The increase in reimbursements and allocations for the first half of 2015 was the result of higher salary costs and a greater number of field workers on Whiting-operated properties, primarily related to the Kodiak Acquisition. Our general and administrative expenses as a percentage of oil, NGL and natural gas sales increased from 4% in the first half of 2014 to 8% for the first half of 2015 as a result of lower sales revenue between periods, as well as the increase in G&A costs discussed above.

Our general and administrative expenses on a BOE basis, however, decreased when comparing the first half of 2015 to the same 2014 period. G&A expense per BOE amounted to $2.92 during the first half of 2015, which represents a decrease of $0.65 per BOE (or 18%) from the first half of 2014. This decrease was mainly due to higher overall production volumes between periods, as well as cost reduction measures implemented by the Company.

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

	Six Months Ended June 30,	
	2015	2014
Senior Notes, Convertible Senior Notes and Senior Subordinated Notes	$ 129,593	$ 73,031
Credit agreement	17,024	2,312
Amortization of debt issue costs, discounts and premiums	19,828	7,342
Other	17	26
Capitalized interest	(3,029)	(1,522)
Total	$ 163,433	$ 81,189

The increase in interest expense of $82 million between periods was mainly attributable to $57 million in higher interest costs incurred on our notes during 2015, a $15 million increase in the amount of interest incurred on our credit agreement during the first half of 2015 as compared to the first half of 2014, and a $12 million increase in amortization of debt issue costs, discounts and premiums. The increase in note interest is due to interest costs incurred on the $1.6 billion of Kodiak Notes we assumed on December 8, 2014 as part of the Kodiak Acquisition, as well as our March 2015 issuance of $750 million of 6.25% Senior Notes due 2023 and $1,250 million of 1.25% Convertible Senior Notes due 2020. During the first half of 2015, we repurchased $752 million of the $1.6 billion Kodiak Notes. Our credit agreement interest was higher in 2015 due to a greater amount of borrowings outstanding under this facility.

Our weighted average debt outstanding during the first half of 2015 was $5.8 billion versus $2.7 billion for the first half of 2014. Our weighted average effective cash interest rate was 5.1% during the first half of 2015 compared to 5.7% for the first half of 2014.

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Commodity Derivative Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity 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 from the counterparty. Commodity derivative loss, net amounted to a loss of $93 million for the six months ended June 30, 2015 mainly due to the upward shift in the futures curve of forecasted commodity prices ("forward price curve") for crude oil from January 1, 2015 (or the 2015 date on which new contracts were entered into) to June 30, 2015. Commodity derivative loss, net for the six months ended June 30, 2014 resulted in a loss of $51 million due to the slightly more significant upward shift in the same forward price curve from January 1, 2014 (or the 2014 date on which prior year contracts were entered into) to June 30, 2014.

See Item 3, "Quantitative and Qualitative Disclosures about Market Risk," for a list of our outstanding derivatives as of July 1, 2015.

Income Tax Expense (Benefit). Income tax benefit for the first half of 2015 totaled $131 million as compared to $176 million of income tax expense for the first half of 2014, a decrease of $307 million that was mainly related to $823 million in lower pre-tax income between periods.

Our effective tax rates for the periods ending June 30, 2015 and 2014 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate decreased from 40.4% for the first half of 2014 to 33.9% for the first half of 2015. This decrease is mainly the result of pre-tax earnings shifting from net income in the first half of 2014 to a net loss in the first half of 2015, as well as increased apportionment to states with higher tax rates during the first half of 2014, which did not occur in 2015.

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

	Three Months Ended June 30,	
	2015	2014
Net production:		
Oil (MMBbl)	12.4	8.0
NGLs (MMBbl)	1.3	0.8
Natural gas (Bcf)	10.6	7.2
Total production (MMBOE)	15.5	10.0
Net sales (in millions):		
Oil (1)	$ 608.2	$ 745.2
NGLs	21.9	30.9
Natural gas	20.4	49.7
Total oil, NGL and natural gas sales	$ 650.5	$ 825.8
Average sales prices:		
Oil (per Bbl) (1)	$ 48.95	$ 93.03
Effect of oil hedges on average price (per Bbl)	3.32	(0.64)
Oil net of hedging (per Bbl)	$ 52.27	$ 92.39

Weighted average NYMEX price (per Bbl) (2)	$ 57.95	$ 103.03
NGLs (per Bbl)	$ 16.86	$ 39.30
Natural gas (per Mcf)	$ 1.92	$ 6.95
Weighted average NYMEX price (per Mcf) (2)	$ 2.61	$ 4.68
Cost and expenses (per BOE):		
Lease operating expenses	$ 9.25	$ 11.85
Production taxes	$ 3.66	$ 6.89
Depreciation, depletion and amortization	$ 20.81	$ 26.88
General and administrative	$ 2.90	$ 3.56

(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 $175 million to $651 million when comparing the second quarter of 2015 to the same period in 2014. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 55%, our NGL sales volumes increased 65%, and our natural gas sales volumes increased 48% between periods. The oil volume increase between periods resulted primarily from producing properties acquired in the Kodiak Acquisition, as well as drilling success at our Redtail, Hidden Bench/Tarpon and Missouri Breaks fields. The Kodiak Acquisition, which closed on December 8, 2014, added 3,130 MBbl of oil production across several of our Northern Rockies areas during the second quarter of 2015. In addition, oil production from our Redtail field increased 655 MBbl, Hidden Bench/Tarpon fields increased 640 MBbl, and our Missouri Breaks field increased 430 MBbl over the same period in 2014 as a result of drilling. Our NGLs are generally produced concurrently with our crude oil volumes, resulting in a high correlation between fluctuations in our oil quantities sold and our NGL quantities sold. As a result, our NGL sales volume increases generally related to the same areas as our oil volume increases, such as our Redtail field and our Hidden Bench/Tarpon fields, as well as NGL production added from the Kodiak Acquisition. The gas volume increase between periods was primarily the result of new wells drilled and completed during the past twelve months, which caused increases in associated gas production of 870 MMcf at our Redtail field, 615 MMcf at our Hidden Bench/Tarpon fields, 475 MMcf at our Sanish and Parshall fields and 235 MMcf at our Cassandra field. In addition, 2,165 MMcf of gas production was added as a result of the Kodiak Acquisition. These gas volume increases were partially offset by the property divestitures in April and June of 2015 which negatively impacted gas production by 860 MMcf during the second quarter of 2015, as well as normal field production decline across several of our areas.

These crude oil, NGL and natural gas production-related increases in net revenue were offset by decreases in the average sales price realized for oil, NGLs and natural gas in the second quarter of 2015 compared to 2014. Our average price for oil before the effects of hedging decreased 47%, our average price for NGLs decreased 57%, and our average price for natural gas decreased 72% between periods.

Gain (Loss) on Sale of Properties. During the second quarter of 2015, we sold our interests in certain producing oil and gas wells for an aggregate purchase price of $293 million, which resulted in a pre-tax loss on sale of $65 million. There were no other property divestitures resulting in a significant gain or loss on sale during the second quarter of 2015 or 2014.

Lease Operating Expenses. Our lease operating expenses during the second quarter of 2015 were $143 million, a $25 million increase over the same period in 2014. Higher LOE in 2015 were primarily related to a $23 million increase in oil field goods and services associated with net wells we added during the last twelve months as a result of the Kodiak Acquisition and through drilling, partially offset by the impact of our property divestitures in the second quarter of 2015.

Our lease operating expenses on a BOE basis, however, decreased during the second quarter of 2015. LOE per BOE amounted to $9.25 during the second quarter of 2015, which represents a decrease of $2.60 per BOE (or 22%) from the second quarter of 2014. This decrease was mainly due to declining costs of goods and services in the industry combined with higher overall production volumes between periods and the impact of our property divestitures discussed above. The properties sold during the second quarter of 2015 consisted mainly of mature oil and gas producing properties with LOE per BOE rates that were higher than our overall rate.

Production Taxes. Our production taxes during the second quarter of 2015 were $57 million, a $12 million decrease over the same period in 2014, 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 8.7% and 8.3% for the second quarter of 2015 and 2014, respectively.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization expense increased $54 million in 2015 as compared to the second quarter of 2014. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended June 30, 2015	2014
Depletion	$ 316,752	$ 263,786
Depreciation	2,366	1,276
Accretion of asset retirement obligations	3,293	3,447
Total	$ 322,411	$ 268,509

DD&A increased in the second quarter of 2015 primarily due to $53 million in higher depletion expense between periods. Of this increase, $113 million related to an increase in our overall production volumes during the second quarter of 2015 which was partially offset by a $60 million decrease related to a lower depletion rate between periods. On a BOE basis, our overall DD&A rate of $20.81 for the second quarter of 2015 was 23% lower than the rate of $26.88 for the same period in 2014. The primary factors contributing to this lower DD&A rate were additions to proved and proved developed reserves over the last twelve months, including reserves that

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were added as a result of the Kodiak Acquisition, as well as impairment write-downs on proved oil and gas properties recognized in the fourth quarter of 2014. The positive impact of these factors was partially offset by $3.2 billion in drilling and development expenditures during the last twelve months.

Exploration and Impairment Costs. Our exploration and impairment costs increased $26 million for the second quarter of 2015 as compared to the same period in 2014. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended June 30,	
	2015	2014
Exploration	$ 32,421	$ 13,466
Impairment	25,136	18,046
Total	$ 57,557	$ 31,512

Exploration costs increased $19 million during the second quarter of 2015 as compared to the same period in 2014 primarily due to rig termination fees of $22 million incurred in 2015.

Impairment expense for the second quarter of 2015 and 2014 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $24 million during the second quarter of 2015 as compared to $18 million in the second quarter of 2014. This increase in impairment expense in 2015 is due to $1.0 billion in unproved property costs added as a result of the Kodiak Acquisition.

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 June 30,	
	2015	2014
General and administrative expenses	$ 80,509	$ 64,780
Reimbursements and allocations	(35,522)	(29,225)
General and administrative expenses, net	$ 44,987	$ 35,555

G&A expense before reimbursements and allocations increased $16 million during the second quarter of 2015 as compared to the same period in 2014 primarily due to higher employee compensation between periods. Employee compensation increased $12 million for the second quarter of 2015 as compared to the same period in 2014 due to personnel hired during the past twelve months, primarily related to the Kodiak Acquisition, as well as general pay increases.

The increase in reimbursements and allocations for the second quarter of 2015 was the result of higher salary costs and a greater number of field workers on Whiting-operated properties, primarily related to the Kodiak Acquisition. Our general and administrative expenses as a percentage of oil, NGL and natural gas sales increased from 4% in the second quarter of 2014 to 7% for the second quarter of 2015 as a result of lower sales revenue between periods, as well as the increase in G&A costs discussed above.

Our general and administrative expenses on a BOE basis, however, decreased during the second quarter of 2015. G&A expense per BOE amounted to $2.90 during the second quarter of 2015, which represents a decrease of $0.66 per BOE (or 19%) from the second quarter of 2014. This decrease was mainly due to higher overall production volumes between periods, as well as cost reduction measures implemented by the Company.

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

	Three Months Ended June 30,	
	2015	2014
Senior Notes, Convertible Senior Notes and Senior Subordinated Notes	$ 68,533	$ 36,688
Credit agreement	4,196	1,190
Amortization of debt issue costs, discounts and premiums	17,828	1,983
Other	15	1
Capitalized interest	(1,396)	(817)
Total	$ 89,176	$ 39,045

The increase in interest expense of $50 million between periods was mainly attributable to $32 million in higher interest costs incurred on our notes during 2015 and a $16 million increase in amortization of debt issue costs, discounts and premiums during the second quarter of 2015 as compared to the second quarter of 2014. This increase in note interest is primarily due to interest costs incurred on the $800 million of 8.125% Senior Notes due December 2019 we assumed on December 8, 2014 as part of the Kodiak Acquisition, as well as our March 2015 issuance of $750 million of 6.25% Senior Notes due 2023 and $1,250 million of 1.25% Convertible Senior Notes due 2020. The increase in amortization of debt issue costs, discounts and premiums is primarily due to the amortization of the discount on the Convertible Senior Notes.

Our weighted average debt outstanding during the second quarter of 2015 was $5.6 billion versus $2.7 billion for the second quarter of 2014. Our weighted average effective cash interest rate was 5.2% during the second quarter of 2015 compared to 5.7% for the second quarter of 2014.

Commodity Derivative Loss, Net. All of our commodity derivative contracts as well as our embedded derivatives are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings, as commodity 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 from the counterparty. Commodity derivative loss, net amounted to a loss of $102 million for the three months ended June 30, 2015 mainly due to the upward shift in the forward price curve for crude oil from April 1, 2015 (or the 2015 date on which new contracts were entered into) to June 30, 2015. Commodity derivative loss, net for the three months ended June 30, 2014, resulted in a loss of $26 million due to the less significant upward shift in the same forward price curve for crude oil from April 1, 2014 (or the 2014 date on which prior year contracts were entered into) to June 30, 2014.

See Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding derivatives as of July 1, 2015.

Income Tax Expense (Benefit). Income tax benefit for the second quarter of 2015 totaled $77 million as compared to $100 million of income tax expense for the second quarter of 2014, a decrease of $177 million that was mainly related to $478 million in lower pre-tax income between periods.

Our effective tax rates for the periods ending June 30, 2015 and 2014 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences. Our overall effective tax rate decreased from 39.8% for the second quarter of 2014 to 34.1% for the second quarter of 2015. This decrease is mainly a result of pre-tax earnings shifting from net income in the second quarter of 2014 to a net loss in the second quarter of 2015, as well as increased apportionment to states with higher tax rates during the second quarter of 2014, which did not occur in 2015.

Liquidity and Capital Resources

Overview. At June 30, 2015, we had $60 million of cash on hand and $6.7 billion of equity, while at December 31, 2014, we had $78 million of cash on hand and $5.7 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 81% and 80% of our total production in the first half of 2015 and 2014, 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 July 1, 2015, we had derivative contracts covering the sale of approximately 49% of our forecasted oil production volumes for the remainder of 2015. For a list of all of our outstanding derivatives as of July 1, 2015, see Item 3, "Quantitative and Qualitative Disclosures about Market Risk."

During the first half of 2015, we generated $528 million of cash provided by operating activities, a decrease of $364 million over the same period in 2014. Cash provided by operating activities decreased primarily due to lower realized sales prices for oil, NGLs and natural gas, as well as increased lease operating expenses, cash interest expense, exploration costs and general and administrative

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expenses in the first half of 2015. These negative factors were partially offset by higher crude oil, NGL and natural gas production volumes, as well as lower production taxes during the first half of 2015 as compared to the same period in 2014. Refer to "Results of Operations" for more information on the impact of volumes and prices on revenues and for more information on increases and decreases in certain expenses between periods.

During the first half of 2015, cash flows from operating activities plus $2.0 billion in proceeds from the issuance of our Convertible Senior Notes and 2023 Senior Notes, $1.1 billion in proceeds from the issuance of our common stock, and $312 million in proceeds from the sale of oil and gas properties were used to finance $1.7 billion of drilling and development expenditures, $1.4 billion of net repayments under our credit agreement, $758 million for the redemption of the 2021 and 2022 Kodiak Notes and $54 million of debt and equity issuance costs.

Exploration, Development and Undeveloped Acreage Expenditures. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region (in thousands):

	Six Months Ended June 30,	
	2015	2014
Rocky Mountains	$ 1,516,800	$ 1,241,029
Permian Basin (1)	64,091	187,177
Other (2)	5,609	23,712
Total incurred	$ 1,586,500	$ 1,451,918

(1) For the six months ended June 30, 2015 and 2014, amount includes $4 million and $22 million, respectively, primarily related to the development of CO_2 reserves and related facilities at our Bravo Dome field in New Mexico.

(2) Other primarily includes oil and gas properties in Louisiana, Michigan, Oklahoma and Texas.

We continually evaluate our capital needs and compare them to our capital resources. We increased our 2015 exploration and development budget from $2.0 billion to $2.15 billion, which we expect to fund substantially with net cash provided by our operating activities, cash on hand, proceeds from property divestitures and borrowings under our credit facility. The $150 million increase is primarily attributable to our non-operated drilling budget. The overall budget represents a substantial decrease from the $3.2 billion incurred on exploration, development and acreage expenditures during 2014. This reduced capital budget is in response to the significantly lower crude oil prices experienced during the fourth quarter of 2014 and continuing into 2015. We expect to allocate $1,968 million of our 2015 budget to exploration and development activity, $59 million to undeveloped acreage purchases and $123 million to facilities. Although we have only budgeted $59 million for undeveloped leasehold purchases in 2015, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should additional attractive acquisition opportunities arise or exploration and development expenditures exceed $2.15 billion, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, agreements with industry partners or divestitures of certain oil and gas property interests. Our level of exploration, development and acreage expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. With our expected cash flow streams, commodity price hedging strategies, current liquidity levels, 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 June 30, 2015 had a borrowing base of $4.5 billion, with aggregate commitments of $3.5 billion. In April 2015, we entered into an amendment to the credit agreement to reaffirm the existing borrowing base in connection with the May 1, 2015 regular redetermination, as well as to modify certain financial covenants contained in the agreement. We may increase the maximum aggregate amount of commitments under the credit agreement up to the $4.5 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of June 30, 2015, we had $3.5 billion of available borrowing capacity, which was net of $5 million in letters of credit with no borrowings 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. Upon a redetermination of our borrowing base, 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.

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A portion of the revolving credit facility in an aggregate amount not to exceed $100 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 June 30, 2015, $95 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	0.50%	1.50%	0.375%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	0.75%	1.75%	0.375%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.00%	2.00%	0.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.25%	2.25%	0.50%
Greater than or equal to 0.90 to 1.0	1.50%	2.50%	0.50%

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. Except for limited exceptions, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of the net assets of the subsidiaries. The credit agreement requires us, as of the last day of any quarter, (i) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0 and (ii) to not exceed a total senior secured debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 2.5 to 1.0 until the earlier of (a) January 1, 2017 or (b) the commencement of an investment-grade debt rating period as described below, and a total debt to EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 thereafter. We were in compliance with our covenants under the credit agreement as of June 30, 2015. 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.

Under the terms of the credit agreement, at any time during which we have an investment-grade debt rating from Moody's Investors Service, Inc. or Standard & Poor's Ratings Group and we have elected, at our discretion, to effect an investment-grade rating period, (i) certain security requirements, including the borrowing base requirement, and restrictive covenants will cease to apply, (ii) certain other restrictive covenants will become less restrictive, (iii) an asset coverage covenant will be imposed, and (iv) the interest rate margin applicable to all revolving borrowings as well as the commitment fee with respect to the revolving facility will be based upon our debt rating rather than the ratio of outstanding borrowings to the borrowing base.

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 also in September 2013, we issued at 101% of par an additional $400 million of 5.75% Senior Notes due March 2021 (collectively the "2021 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 2023 Senior Notes, the 2021 Senior Notes and the 2019 Senior Notes the "Nonconvertible Whiting Notes").

Convertible Senior Notes. In March 2015, we issued at par $1,250 million of 1.25% Convertible Senior Notes due April 2020 (the "Convertible Senior Notes").

We have the option to settle conversions of the Convertible Senior 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 Convertible Senior Notes in cash upon conversion. Prior to January 1, 2020, the Convertible Senior Notes will be convertible 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 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 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 Convertible Senior Notes in connection with such corporate event. As of June 30, 2015, none of the contingent conditions allowing holders of the Convertible Senior Notes to convert these notes had been met.

Kodiak Senior Notes. In conjunction with the Kodiak Acquisition, Whiting US Holding Company, our wholly-owned subsidiary, became a co-issuer of the Kodiak Notes. Upon closing of the Kodiak Acquisition, the Kodiak Indentures were amended to (i) modify certain covenants and restrictions, (ii) provide for unconditional and irrevocable guarantees by Whiting Petroleum Corporation and Whiting Oil and Gas of the prompt payment, when due, of any amounts owed under the Kodiak Notes and the Kodiak Indentures, and (iii) allow Whiting US Holding Company to become a co-issuer of the Kodiak Notes. Also in conjunction with the Kodiak Acquisition, in December 2014, each of the indentures governing our 2019 Senior Notes, 2021 Senior Notes and 2018 Senior Subordinated Notes were amended to include Whiting US Holding Company, Kodiak and Whiting Resources Corporation as guarantors. The indentures governing our 2023 Senior Notes and Convertible Senior Notes issued in March 2015 also include Whiting Oil and Gas, Whiting US Holding Company, Kodiak and Whiting Resources Corporation as guarantors.

The indentures governing the Nonconvertible Whiting 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. The indentures governing the 2019 Kodiak Notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indenture) is at least 2.25 to 1. If we were in violation of these covenants, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas’ credit agreement. Additionally, the indentures governing the Nonconvertible Whiting Notes and the 2019 Kodiak Notes 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 June 30, 2015. 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 table below does not include any penalties that may be incurred under our physical delivery contracts, since we cannot predict with accuracy the amount and timing of any such penalties if incurred. For further information on our physical delivery contracts, refer to the Commitments and Contingencies footnote in the notes to consolidated financial statements in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the period ended December 31, 2014. The following table summarizes our obligations and commitments as of June 30, 2015 to make future payments under certain contracts, aggregated by category of contractual obligation, for the time periods specified below (in thousands):

	Payments due by period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$ 5,447,550	$ -	$ -	$ 3,497,550	$ 1,950,000
Cash interest expense on debt (2)	1,395,475	274,051	548,102	395,541	177,781
Derivative contract liability fair value (3)	35,455	15,138	17,717	2,600	-
Asset retirement obligations (4)	153,073	6,994	13,803	14,232	118,044
Purchase obligations (5)	114,811	60,387	54,424	-	-
Pipeline transportation agreements (6)	104,193	13,481	19,720	19,118	51,874
Drilling rig contracts (7)	175,837	105,752	70,085	-	-
Operating leases (8)	30,871	7,682	13,773	9,416	-
Total	$ 7,457,265	$ 483,485	$ 737,624	$ 3,938,457	$ 2,297,699

(1) Long-term debt consists of the principal amounts of the Nonconvertible Whiting Notes, the 2019 Kodiak Notes and the Convertible Senior Notes.

(2) Cash interest expense on the Nonconvertible Whiting Notes and the 2019 Kodiak Notes is estimated assuming no principal repayment until the due dates of the instruments. Cash interest expense on the Convertible Senior Notes is estimated assuming no conversion prior to maturity. No cash interest expense is assumed on the credit facility as there were no borrowings outstanding as of June 30, 2015.

(3) The above derivative obligation at June 30, 2015 consists of (i) a $27 million fair value liability for derivative contracts we have entered into in the form of costless collars and swaps to hedge our exposure to crude oil price fluctuations and (ii) an $8 million fair value liability for a crude oil sales and delivery contract for oil volumes produced from our Redtail field. With respect to only a portion of our open derivative contracts at June 30, 2015 with certain counterparties, the forward price curve for crude oil generally exceeded the price curve that was in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar's price ceiling or a swap's fixed price when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market fluctuations.

(4) 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.

(5) We have three take-or-pay purchase agreements, of which one agreement expires in 2015 and two agreements expire in 2017. One of these agreements contains commitments to buy certain volumes of CO_2 for use in our North Ward Estes EOR project in Texas. Under the remaining two take-or-pay agreements, we have committed to buy certain volumes of water for use in the fracture stimulation process of wells in our Redtail field. Under the terms of these agreements, we are obligated to purchase a minimum volume of CO_2 or water, as the case may be, or else pay for any deficiencies at the price stipulated in the contract. The CO_2 volumes planned for use in the EOR project at our North Ward Estes field and the water volumes planned for use at our Redtail field currently exceed the minimum volumes specified in all of these agreements. Therefore, we expect to avoid any payments for deficiencies under these contracts. The purchasing obligations reported above represent our minimum financial commitments pursuant to the terms of these contracts, however, our actual expenditures under these contracts are expected to exceed the minimum commitments presented above.

(6) We have two ship-or-pay agreements with different suppliers, one expiring in 2015 and one expiring in 2017, whereby we have committed to transport a minimum daily volume of CO_2 or water, as the case may be, via certain pipelines or else pay for any deficiencies at a price stipulated in the contracts. In addition, we have three pipeline transportation agreements with one supplier, one expiring in 2024, one expiring in 2025 and one expiring in 2027, 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 June 30, 2015, we had 11 drilling rigs under long-term contract, all of which were operating in the Rocky Mountains region. Subsequent to June 30, 2015, we provided notice to our counterparties to three of these long-term drilling contracts of our intent to early terminate such contracts on or around September 1, 2015. We expect to incur early termination penalties totaling approximately $26 million, which would be in lieu of paying the remaining drilling commitments under these contracts of $27 million. Of the remaining eight long-term contracts, two expire in 2016 and six in 2017. As of June 30, 2015, early termination of the remaining eight contracts would require termination penalties of $123 million, which would be in lieu of paying the remaining drilling commitments under these contracts.

(8)

We lease 204,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2019, 47,900 square feet of office space in Midland, Texas expiring in 2020, an additional 36,300 square feet of administrative office space in Denver, Colorado assumed in the Kodiak Acquisition expiring in 2016, and 20,000 square feet of office space in Dickinson, North Dakota expiring in 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 any obligations arising as a result of the Kodiak Acquisition and funding our operating, exploration and development 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 the Adopted and Recently Issued Accounting Pronouncements 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, 2014.

Effects of Inflation and Pricing

We experienced increased costs during 2014 due to increased demand for oil field products and services, however, costs in the first half of 2015 have begun to decline following a decrease in demand for these same products and services. The oil and gas industry is very cyclical, and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, 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 oil, NGL or natural gas prices; our level of success in exploration, development and production activities; risks related to our level of indebtedness 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; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures; our ability to obtain sufficient quantities of CO_2 necessary to carry out our EOR projects; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices, regulation and other factors; 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 and acquisitions; federal and state initiatives relating to the regulation of hydraulic fracturing; 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; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; 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 our Annual Report on Form 10 K for the period ended December 31, 2014. 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

Our quantitative and qualitative disclosures about market risk for changes in interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2014 and have not materially changed since that report was filed.

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 half of 2015, our income (loss) before income taxes for the six months ended June 30, 2015 would have moved up or down $109 million for each 10% change in oil prices per Bbl, $4 million for each 10% change in NGL prices per Bbl and $5 million for each 10% change in natural gas prices per Mcf.

We periodically enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars and swap contracts, 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 and Swaps. The collared hedges shown in the tables 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. For the crude oil collars outstanding as of June 30, 2015, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of June 30, 2015 would cause a decrease or increase, respectively, of $111 million in our commodity derivative loss.

The swap contracts shown in the tables below entitle us to receive settlement from the counterparty in amounts, if any, by which the settlement price for the applicable calculation period is less than the fixed price, or to pay the counterparty if the settlement price for the applicable calculation period is more than the fixed price. While the fixed-price swaps are designed to decrease our exposure to downward price movements, they also have the effect of limiting the benefit of upward price movements. For the swaps outstanding as of June 30, 2015, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of June 30, 2015 would cause a decrease or increase, respectively, of $9 million in our commodity derivative loss.

Our outstanding hedges as of July 1, 2015 are summarized below:

Derivative	Monthly Volume	Weighted Average

Instrument	Commodity	Period	(Bbl)	NYMEX Sub-Floor/Floor/Ceiling
Three-way collars (1)	Crude oil	07/2015 to 09/2015	1,450,000	$44.48/$54.83/$70.54
	Crude oil	10/2015 to 12/2015	1,450,000	$44.48/$54.83/$70.54
	Crude oil	01/2016 to 03/2016	1,400,000	$43.75/$53.75/$74.40
	Crude oil	04/2016 to 06/2016	1,400,000	$43.75/$53.75/$74.40
	Crude oil	07/2016 to 09/2016	1,400,000	$43.75/$53.75/$74.40
	Crude oil	10/2016 to 12/2016	1,400,000	$43.75/$53.75/$74.40

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Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Sub-Floor/Floor/Ceiling
Collars	Crude oil	07/2015 to 09/2015	209,200	$51.06/$57.37
	Crude oil	10/2015 to 12/2015	209,200	$51.06/$57.37
	Crude oil	01/2016 to 03/2016	250,000	$51.00/$63.48
	Crude oil	04/2016 to 06/2016	250,000	$51.00/$63.48
	Crude oil	07/2016 to 09/2016	250,000	$51.00/$63.48
	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
Swaps	Crude oil	07/2015 to 09/2015	259,160	$76.57
	Crude oil	10/2015 to 12/2015	251,230	$76.25

(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.

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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 June 30, 2015. 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 June 30, 2015 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 June 30, 2015 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. It is management's opinion that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

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, 2014. The following is a material update to such risk factors:

The Convertible Senior Notes may adversely affect the market price of our common stock.

The market price of our common stock is likely to be influenced by the Convertible Senior 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 the Convertible Senior Notes;
- possible sales of our common stock by investors who view the Convertible Senior 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 the Convertible Senior 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.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on this 30th day of July, 2015.

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
(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 June 30, 2015 are filed herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of June 30, 2015 and December 31, 2014, (ii) the Consolidated Statements of Income for the Three and Six Months Ended June 30, 2015 and 2014, (iii) the Consolidated Statements of Cash Flows for the Six Months Ended June 30, 2015 and 2014, (iv) the Consolidated Statements of Equity for the Six Months Ended June 30, 2015 and 2014 and (v) Notes to Consolidated Financial Statements.