WHITING PETROLEUM CORP
Form 10-Q
May 01, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2014

or

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

For the transition period from _______________ to _______________

Commission file number: 001-31899

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes T 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 T 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 filerT	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 T

Number of shares of the registrant's common stock outstanding at April 15, 2014: 118,959,061 shares.

TABLE OF CONTENTS

	Glossary of Certain Definitions	1

PART I – FINANCIAL INFORMATION

Item 1.	Consolidated Financial Statements (Unaudited)	4
	Consolidated Balance Sheets as of March 31, 2014 and December 31, 2013	4
	Consolidated Statements of Income for the Three Months Ended March 31, 2014 and 2013	5
	Consolidated Statements of Comprehensive Income for the Three Months Ended March 31, 2014 and 2013	6
	Consolidated Statements of Cash Flows for the Three Months Ended March 31, 2014 and 2013	7
	Consolidated Statements of Equity for the Three Months Ended March 31, 2014 and 2013	8
	Notes to Consolidated Financial Statements	9
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	25
Item 3.	Quantitative and Qualitative Disclosure About Market Risk	37
Item 4.	Controls and Procedures	38

PART II – OTHER INFORMATION

Item 1.	Legal Proceedings	40
Item 1A.	Risk Factors	40
Item 6.	Exhibits	40
	Certification by the Chairman and Chief Executive Officer	
	Certification by the Vice President and Chief Financial Officer	
	Written Statement of the Chief Executive Officer	
	Written Statement of the Chief Financial Officer	

Table of Contents

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 options position where the proceeds from the sale of a call option at its inception fund the purchase of a put option at its inception.

“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.

“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.

“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 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.

Table of Contents

“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 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 CO2.

“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 CO2.

“MMcf/d” One MMcf per day.

“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 perforations in 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 many states require plugging of abandoned wells.

“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.

2

Table of Contents

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

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

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

“proved undeveloped reserves” 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 for 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.

“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.

“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 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.

3

Table of Contents

PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

WHITING PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS (unaudited)
(in thousands, except share and per share data)

	March 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 406,437	$ 699,460
Accounts receivable trade, net	378,111	341,177
Prepaid expenses and other	38,059	28,981
Total current assets	822,607	1,069,618
Property and equipment:		
Oil and gas properties, successful efforts method	10,642,189	10,065,150
Other property and equipment	225,106	206,385
Total property and equipment	10,867,295	10,271,535
Less accumulated depreciation, depletion and amortization	(2,889,910)	(2,676,490)
Total property and equipment, net	7,977,385	7,595,045
Debt issuance costs	45,535	48,530
Other long-term assets	136,197	120,277
TOTAL ASSETS	$ 8,981,724	$ 8,833,470
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 116,673	$ 107,692
Accrued capital expenditures	210,133	158,739
Accrued liabilities and other	109,607	214,109
Revenues and royalties payable	197,416	198,558
Taxes payable	55,268	50,052
Accrued interest	17,676	44,405
Derivative liabilities	11,799	3,482
Deferred income taxes	8,786	648
Total current liabilities	727,358	777,685
Long-term debt	2,653,674	2,653,834
Deferred income taxes	1,345,253	1,278,030
Production Participation Plan liability	91,139	87,503
Asset retirement obligations	146,188	116,442
Deferred gain on sale	72,250	79,065
Other long-term liabilities	4,365	4,212
Total liabilities	5,040,227	4,996,771
Commitments and contingencies		
Equity:		
Common stock, $0.001 par value, 300,000,000 shares authorized; 120,614,246 issued and	121	120

118,959,061 outstanding as of March 31, 2014 and 120,101,555 issued and 118,657,245 outstanding as of December 31, 2013				
Additional paid-in capital		1,579,288		1,583,542
Retained earnings		2,353,974		2,244,905
Total Whiting shareholders' equity		3,933,383		3,828,567
Noncontrolling interest		8,114		8,132
Total equity		3,941,497		3,836,699
TOTAL LIABILITIES AND EQUITY	$	8,981,724	$	8,833,470

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME (unaudited)
(in thousands, except per share data)

	Three Months Ended March 31, 2014	2013
REVENUES AND OTHER INCOME:		
Oil, NGL and natural gas sales	$ 721,250	$ 605,114
Loss on hedging activities	-	(211)
Amortization of deferred gain on sale	7,744	7,976
Gain on sale of properties	10,559	-
Interest income and other	696	492
Total revenues and other income	740,249	613,371
COSTS AND EXPENSES:		
Lease operating	114,786	99,878
Production taxes	60,030	51,271
Depreciation, depletion and amortization	235,265	201,159
Exploration and impairment	42,107	37,280
General and administrative	32,334	28,885
Interest expense	42,144	21,470
Change in Production Participation Plan liability	3,636	4,407
Commodity derivative loss, net	24,535	31,257
Total costs and expenses	554,837	475,607
INCOME BEFORE INCOME TAXES	185,412	137,764
INCOME TAX EXPENSE:		
Current	1,000	422
Deferred	75,361	51,098
Total income tax expense	76,361	51,520
NET INCOME	109,051	86,244
Net loss attributable to noncontrolling interest	18	19
NET INCOME AVAILABLE TO SHAREHOLDERS	109,069	86,263
Preferred stock dividends	-	(269)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 109,069	$ 85,994
EARNINGS PER COMMON SHARE:		
Basic	$ 0.92	$ 0.73
Diluted	$ 0.91	$ 0.72
WEIGHTED AVERAGE SHARES OUTSTANDING:		
Basic	118,923	117,788
Diluted	119,931	119,263

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (unaudited)
(in thousands)

	Three Months Ended March 31, 2014		Three Months Ended March 31, 2013	
NET INCOME	$	109,051	$	86,244
OTHER COMPREHENSIVE INCOME, NET OF TAX:				
OCI amortization on de-designated hedges(1)(2)		-		133
Total other comprehensive income, net of tax		-		133
COMPREHENSIVE INCOME		109,051		86,377
Comprehensive loss attributable to noncontrolling interest		18		19
COMPREHENSIVE INCOME ATTRIBUTABLE TO WHITING	$	109,069	$	86,396

(1) Presented net of income tax expense of $78 for the three months ended March 31, 2013.

(2) These gain amounts on de-designated hedges are reclassified from accumulated other comprehensive income ("AOCI") to loss on hedging activities in the consolidated statements of income.

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
(in thousands)

	Three Months Ended March 31, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 109,051	$ 86,244
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	235,265	201,159
Deferred income tax expense	75,361	51,098
Amortization of debt issuance costs and debt premium	5,360	2,435
Stock-based compensation	6,732	6,728
Amortization of deferred gain on sale	(7,744)	(7,976)
Gain on sale of properties	(10,559)	-
Undeveloped leasehold and oil and gas property impairments	17,985	18,414
Exploratory dry hole costs	3,552	-
Change in Production Participation Plan liability	3,636	4,407
Non-cash portion of derivative losses	23,793	26,164
Other, net	(1,041)	(6,200)
Changes in current assets and liabilities:		
Accounts receivable trade	(36,936)	(13,531)
Prepaid expenses and other	(15,161)	(8,379)
Accounts payable trade and accrued liabilities	(89,471)	(59,385)
Revenues and royalties payable	(1,142)	(9,463)
Taxes payable	5,216	5,899
Net cash provided by operating activities	323,897	297,614
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and development capital expenditures	(596,407)	(536,690)
Acquisition of oil and gas properties	(33,696)	(14,887)
Other property and equipment	(24,474)	(29,698)
Proceeds from sale of oil and gas properties	75,023	-
Issuance of note receivable	-	(2,316)
Cash paid for investing derivatives	-	(44,900)
Net cash used in investing activities	(579,554)	(628,491)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Long-term borrowings under credit agreement	-	650,000
Repayments of long-term borrowings under credit agreement	-	(350,000)
Debt issuance costs	(8)	(72)
Proceeds from stock options exercised	88	-

Restricted stock used for tax withholdings		(11,073)		(5,400)
Repayment of tax sharing liability		(26,373)		-
Preferred stock dividends paid		-		(269)
Net cash provided by (used in) financing activities		(37,366)		294,259
NET CHANGE IN CASH AND CASH EQUIVALENTS		(293,023)		(36,618)
CASH AND CASH EQUIVALENTS:				
Beginning of period		699,460		44,800
End of period	$	406,437	$	8,182
NONCASH INVESTING ACTIVITIES:				
Accrued capital expenditures	$	210,133	$	109,312

See notes to consolidated financial statements.

Table of Contents

WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY (unaudited)
(in thousands)

	Preferred Stock		Common Stock		Additional Paid-in	Accumulated Other Comprehensive Income	Retained	Total Whiting Shareholders'	Noncontrolling	Total
	Shares	Amount	Shares	Amount	Capital	(Loss)	Earnings	Equity	Interest	Equity
BALANCES-January 1, 2013	172	$-	118,582	$119	$1,566,717	$(1,236)	$1,879,388	$3,444,988	$8,184	$3,453,172
Net income (loss)	-	-	-	-	-	-	86,263	86,263	(19)	86,244
Other comprehensive income	-	-	-	-	-	133	-	133	-	133
Conversion of preferred stock to common	-	-	1	-	-	-	-	-	-	-
Restricted stock issued	-	-	920	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(2)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(111)	-	(5,400)	-	-	(5,400)	-	(5,400)
Stock-based compensation	-	-	-	-	6,728	-	-	6,728	-	6,728
Preferred dividends paid	-	-	-	-	-	-	(269)	(269)	-	(269)
BALANCES-March 31, 2013	172	$-	119,390	$119	$1,568,045	$(1,103)	$1,965,382	$3,532,443	$8,165	$3,540,608
BALANCES-January 1, 2014	-	$-	120,102	$120	$1,583,542	$-	$2,244,905	$3,828,567	$8,132	$3,836,699
Net income (loss)	-	-	-	-	-	-	109,069	109,069	(18)	109,051
Exercise of stock options	-	-	3	-	88	-	-	88	-	88
Restricted stock issued	-	-	894	1	(1)	-	-	-	-	-
Restricted stock forfeited	-	-	(197)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(188)	-	(11,073)	-	-	(11,073)	-	(11,073)
Stock-based compensation	-	-	-	-	6,732	-	-	6,732	-	6,732
BALANCES-March 31, 2014	-	$-	120,614	$121	1,579,288	$-	$2,353,974	$3,933,383	$8,114	$3,941,497

See notes to consolidated financial statements.

8

Table of Contents

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 that explores for, develops, acquires and produces 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.

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. 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. Whiting's 2013 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Quarterly Report on Form 10-Q. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in Whiting's 2013 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 and outstanding stock options using the treasury method, as well as convertible perpetual preferred stock using the if-converted 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 share method to the extent that such excess tax benefits are more likely than not to be realized. 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 March 31, 2014 and December 31, 2013 are as follows (in thousands):

Table of Contents

	March 31, 2014	December 31, 2013
Proved leasehold costs	$1,678,821	$1,633,495
Unproved leasehold costs	351,211	372,298
Costs of completed wells and facilities	8,087,496	7,563,350
Wells and facilities in progress	524,661	496,007
Total oil and gas properties, successful efforts method	10,642,189	10,065,150
Accumulated depletion	(2,857,602)	(2,645,841)
Oil and gas properties, net	$7,784,587	$7,419,309

3. ACQUISITIONS AND DIVESTITURES

2014 Acquisitions

There were no significant acquisitions during the three months ended March 31, 2014.

2014 Divestitures

On March 27, 2014, the Company completed the sale of approximately 49,900 gross (41,000 net) acres, which consisted mainly of undeveloped acreage as well as its interests in certain producing oil and gas wells, in its Big Tex prospect located in the Delaware Basin of Texas for a cash purchase price of $76.2 million (subject to post-closing adjustments) resulting in a pre-tax gain on sale of $11.9 million.

2013 Acquisitions

On September 20, 2013, the Company completed the acquisition of approximately 39,300 gross (17,300 net) acres, including interests in 121 producing oil and gas wells and undeveloped acreage, in the Williston Basin located in Williams and McKenzie counties of North Dakota and Roosevelt and Richland counties of Montana for an aggregate unadjusted purchase price of $260.0 million. Revenue and earnings from these properties since the September 20, 2013 acquisition date, which are included in the consolidated statements of income for the three months ended March 31, 2014, are not material. Disclosures of pro forma revenues and net income for the acquisition of these wells are therefore not material and have not been presented accordingly.

The acquisition was recorded using the purchase method of accounting. The following table summarizes the allocation of the $254.7 million adjusted purchase price to the tangible assets acquired and liabilities assumed in this acquisition oil and gas properties (in thousands):

Purchase price	$254,681
Allocation of purchase price:	
Proved properties	$228,146
Unproved properties	27,335
Oil in tank inventory	522
Accounts receivable	578
Asset retirement obligations	(1,900)
Total	$254,681

2013 Divestitures

On October 31, 2013, the Company completed the sale of approximately 45,000 gross (32,200 net) acres, which consisted mainly of undeveloped acreage as well as its interests in certain producing oil and gas wells, in its Big Tex prospect located in the Delaware Basin of Texas for a cash purchase price of $150.8 million, resulting in a pre-tax gain on sale of $11.6 million. Of the total net acres sold, approximately 30,800 net acres are located in Pecos County, Texas, and approximately 1,400 net acres are located in Reeves County, Texas.

On July 15, 2013, the Company completed the sale of its interests in certain oil and gas producing properties located in its EOR projects in the Postle and Northeast Hardesty fields in Texas County, Oklahoma, including the related Dry Trail plant gathering and processing facility, oil delivery pipeline, its entire 60% interest in the Transpetco CO2 pipeline, crude oil swap contracts and certain other related assets and liabilities (collectively the "Postle Properties") for a cash purchase price of $809.7 million after selling costs and post-closing adjustments. This divestiture resulted in a pre-tax gain on sale of $109.7 million. The Company used the net proceeds from this sale to repay a portion of the debt outstanding under its credit agreement.

4. LONG-TERM DEBT

Long-term debt consisted of the following at March 31, 2014 and December 31, 2013 (in thousands):

	March 31, 2014	December 31, 2013
6.5% Senior Subordinated Notes due 2018	$350,000	$350,000
5% Senior Notes due 2019	1,100,000	1,100,000
5.75% Senior Notes due 2021, including unamortized debt premium of $3,674 and $3,834, respectively	1,203,674	1,203,834
Total debt	$2,653,674	$2,653,834

Credit Agreement—Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), the Company's wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of March 31, 2014 had a borrowing base of $2.8 billion, of which $1.2 billion has been committed by lenders and is available for borrowing. The Company may increase the maximum aggregate amount of commitments under the credit agreement up to the $2.8 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of March 31, 2014, the Company had $1,197.0 million of available borrowing capacity, which was net of $3.0 million in letters of credit with no borrowings outstanding.

The credit agreement provides for interest only payments until the expiration date of the agreement, when all outstanding borrowings are due. In April 2014, Whiting Oil and Gas entered into an amendment to its credit agreement that extended the principal repayment date from April 2016 to the earlier of (i) April 2, 2019 or (ii) with certain exceptions, the date that is 91 days prior to the scheduled maturity of any permitted additional unsecured senior or senior subordinated notes, which includes the Company's 5% Senior Notes due March 2019, unless redeemed earlier in accordance with the credit agreement.

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. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 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 March 31, 2014, $47.0 million was available for additional letters of credit under the agreement.

Interest 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 0.50% or an adjusted LIBOR rate plus 1.00%, 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 lesser of the aggregate commitments of the lenders or the borrowing base, and 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 Whiting Oil and Gas. As of March 31, 2014, total restricted net assets were $4,258.0 million, and the amount of retained earnings free from restrictions was $23.5 million. The credit agreement requires the Company, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) 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. The Company was in compliance with its covenants under the credit agreement as of March 31, 2014.

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' 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 Whiting Oil and Gas as security for its guarantee.

Senior Notes and Senior Subordinated Notes—In September 2010, the Company issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018 (the "2018 Notes"). The estimated fair value of these notes was $367.5 million as of March 31, 2014, based on quoted market prices for these debt securities, and such fair value is therefore designated as Level 1 within the valuation hierarchy.

Issuance of Senior Notes. In September 2013, the Company issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021, and issued at 101% of par an additional $400.0 million of 5.75% Senior Notes due March 2021 (collectively, the "Senior Notes"). The estimated fair values of the 2019 notes and the 2021 notes were $1,161.9 million and $1,281.0 million, respectively, as of March 31, 2014, based on quoted market prices for these debt securities, and such fair values are therefore designated as Level 1 within the valuation hierarchy.

The Senior Notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's secured indebtedness, which consists of Whiting Oil and Gas' credit agreement. The 2018 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 Senior Notes and Whiting Oil and Gas' credit agreement. The Company's obligations under the 2018 Notes and the Senior Notes are fully and unconditionally guaranteed by the Company's 100%-owned subsidiary, Whiting Oil and Gas (the "Guarantor"). Any subsidiaries other than the Guarantor 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.

Table of Contents

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 March 31, 2014 and December 31, 2013 were $7.2 million and $9.7 million, respectively, and are 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 three months ended March 31, 2014 (in thousands):

Asset retirement obligation at January 1, 2014	$126,148
Additional liability incurred	5,082
Revisions in estimated cash flows (1)	20,594
Accretion expense	3,096
Obligations on sold properties	(382)
Liabilities settled	(1,193)
Asset retirement obligation at March 31, 2014	$153,345

(1) Revisions in estimated cash flows during the three months ended March 31, 2014 are primarily attributable to increased estimates of future costs for oilfield services and related materials required to plug and abandon wells in certain fields in the Rocky Mountains region.

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, primarily costless collars and swaps, 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. 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 Company does not enter into derivative contracts for speculative or trading purposes.

Whiting Derivatives. The table below details the Company's costless collar derivatives, including its proportionate share of Whiting USA Trust II ("Trust II") derivatives, entered into to hedge forecasted crude oil production revenues, as of April 1, 2014.

Table of Contents

		Whiting Petroleum Corporation	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	Weighted Average NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Apr – Dec 2014	36,540	\$80.00 - \$122.50
Three-way collars (1)	Apr – Dec 2014	12,420,000	\$71.23 - \$85.36 - \$103.54
	Total	12,456,540	

(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.

In March 2013, Whiting entered into certain crude oil swap contracts in order to achieve more predictable cash flows and manage returns on certain oil and gas properties that the Company was considering for monetization. Accordingly, the acquisition of these swap contracts and cash receipts from settlements of these swap positions have been reflected as an investing activity in the statement of cash flows. On July 15, 2013, upon closing of the sale of the Postle Properties discussed in the Acquisitions and Divestitures footnote, these crude oil swaps were novated to the buyer. Cash settlements that do not relate to investing derivatives or that do not have a significant financing element are reflected as operating activities in the statement of cash flows.

Derivatives Conveyed to Whiting USA Trust II. In connection with the Company's conveyance in March 2012 of a term net profits interest to Trust II and related sale of 18,400,000 Trust II units to the public, the right to any future hedge payments made or received by Whiting on certain of its derivative contracts have been conveyed to Trust II, and therefore such payments will be included in Trust II's calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties, which results in third-party public holders of Trust II units receiving 90%, and Whiting retaining 10%, of the future economic results of commodity derivative contracts conveyed to Trust II. The relative ownership of the future economic results of such commodity derivatives is reflected in the tables below. No additional hedges are allowed to be placed on Trust II assets.

The 10% portion of Trust II derivatives that Whiting has retained the economic rights to (and which are also included in the first derivative table above) are as follows:

		Whiting Petroleum Corporation	
Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Apr – Dec 2014	36,540	\$80.00 - \$122.50

The 90% portion of Trust II derivative contracts of which Whiting has transferred the economic rights to third-party public holders of Trust II units (and which have not been reflected in the above tables) are as follows:

Third-party Public Holders of Trust II Units

Derivative Instrument	Period	Contracted Crude Oil Volumes (Bbl)	NYMEX Price Collar Ranges for Crude Oil (per Bbl)
Collars	Apr – Dec 2014	328,860	$80.00 - $122.50

Embedded Commodity Derivative Contract—In May 2011, Whiting entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in its EOR project that is being carried out at its North Ward Estes field in Texas. This contract contains a price adjustment clause that is linked to changes in NYMEX crude oil prices. The Company has determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to the host contract, and the Company has therefore bifurcated this embedded pricing feature from its host contract and reflected it at fair value in the consolidated financial statements. As of March 31, 2014, the estimated fair value of the embedded derivative in this CO2 purchase contract was an asset of $22.1 million.

Table of Contents

Although CO2 is not a commodity that is actively traded on a public exchange, the market price for CO2 generally fluctuates in tandem with increases or decreases in crude oil prices. When Whiting enters into a long-term CO2 purchase contract where the price of CO2 is fixed and does not adjust with changes in oil prices, the Company is exposed to the risk of paying higher than the market rate for CO2 in a climate of declining oil and CO2 prices. This in turn could have a negative impact on the project economics of the Company's CO2 flood at North Ward Estes. As a result, the Company reduces its exposure to this risk by entering into certain CO2 purchase contracts which have prices that fluctuate along with changes in crude oil prices.

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 tables summarize the effects of commodity derivative instruments on the consolidated statements of income for the three months ended March 31, 2014 and 2013 (in thousands):

ASC 815 Cash Flow Hedging Relationships (1)	Income Statement Classification	Loss Reclassified from AOCI into Income (Effective Portion) (1) Three Months Ended March 31, 2014	2013
Commodity contracts	Loss on hedging activities	$ -	$ (211)

(1) Effective April 1, 2009, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively. As a result, such mark-to-market values at March 31, 2009 were frozen in AOCI as of the de-designation date and were being reclassified into earnings as the original hedged transactions affected income. As of December 31, 2013, all amounts previously in AOCI had been reclassified into earnings.

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Three Months Ended March 31, 2014	2013
Commodity contracts	Commodity derivative loss, net	$ 10,187	$ 34,260
Embedded commodity contracts	Commodity derivative loss, net	14,348	(3,003)
Total		$ 24,535	$ 31,257

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

Table of Contents

		March 31, 2014 (1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 12,058	$ (11,912)	$ 146
Embedded commodity contracts	Prepaid expenses and other	433	-	433
Embedded commodity contracts	Other long-term assets	21,635	-	21,635
Total derivative assets		$ 34,126	$ (11,912)	$ 22,214
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 23,711	$ (11,912)	$ 11,799
Total derivative liabilities		$ 23,711	$ (11,912)	$ 11,799

		December 31, 2013 (1)		
Not Designated as ASC 815 Hedges	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Prepaid expenses and other	$ 23,752	$ (22,478)	$ 1,274
Embedded commodity contracts	Other long-term assets	36,416	-	36,416
Total derivative assets		$ 60,168	$ (22,478)	$ 37,690
Derivative liabilities:				
Commodity contracts	Current derivative liabilities	$ 25,960	$ (22,478)	$ 3,482
Total derivative liabilities		$ 25,960	$ (22,478)	$ 3,482

(1) Because counterparties to the Company’s 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 Derivative Instruments. None of the Company’s derivative instruments contain credit-risk-related contingent features. Counterparties to the Company’s 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 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.

Table of Contents

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

- Level 1: Quoted Prices in Active Markets for Identical Assets – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2: Significant Other Observable Inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3: Significant Unobservable Inputs – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

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

The following tables present information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of March 31, 2014 and December 31, 2013, 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 March 31, 2014
Financial Assets				
Commodity derivatives – current	$ -	$ 146	$ -	$ 146
Embedded commodity derivatives – current	-	-	433	433
Embedded commodity derivatives – non-current	-	-	21,635	21,635
Total financial assets	$ -	$ 146	$ 22,068	$ 22,214
Financial Liabilities				
Commodity derivatives – current	$ -	$ 11,799	$ -	$ 11,799
Total financial liabilities	$ -	$ 11,799	$ -	$ 11,799

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2013
Financial Assets				
Commodity derivatives – current	$ -	$ 1,274	$ -	$ 1,274
Embedded commodity derivatives – non-current	-	-	36,416	36,416

Total financial assets	$	-	$	1,274	$	36,416	$	37,690
Financial Liabilities								
Commodity derivatives – current	$	-	$	3,482	$	-	$	3,482
Total financial liabilities	$	-	$	3,482	$	-	$	3,482

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

Table of Contents

Commodity Derivatives. Commodity derivative instruments consist 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.

Embedded Commodity Derivatives. The embedded commodity derivative relates to a long-term CO_2 purchase contract, which has a price adjustment clause that is linked to changes in NYMEX crude oil prices. Whiting has determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to its corresponding host contract, and the Company has therefore bifurcated this embedded pricing feature from the host contract and reflected it at fair value in its consolidated financial statements. This embedded commodity derivative is valued based on an income approach. The option model used in the valuation considers various assumptions, including quoted forward prices for commodities, LIBOR discount rates and either the Company's or the counterparty's nonperformance risk, as appropriate.

The assumptions used in the CO_2 contract valuation include inputs that are both observable in the marketplace as well as unobservable during the term of the contract. With respect to forward prices for NYMEX crude oil where there is a lack of price transparency in certain future periods, such unobservable oil price inputs are significant to the CO_2 contract valuation methodology, and the contract's fair value is therefore designated as Level 3 within the valuation hierarchy.

Level 3 Fair Value Measurements. A third-party valuation specialist is utilized on a quarterly basis to determine the fair value of the embedded commodity derivative instrument designated as Level 3. The Company reviews this valuation (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 (liabilities) designated as Level 3 in the valuation hierarchy for the three months ended March 31, 2014 and 2013 (in thousands):

	Three Months Ended March 31,	
	2014	2013
Fair value asset, beginning of period	$36,416	$23,715
Unrealized gains (losses) on embedded commodity derivative contracts included in earnings (1)	(14,348)	3,003
Transfers into (out of) Level 3	-	-
Fair value asset, end of period	$22,068	$26,718

(1) Included in commodity derivative loss, net 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 embedded commodity derivative contract designated as Level 3 are as follows:

18

Table of Contents

	Fair Value at March 31, 2014 (in thousands)	Valuation Technique	Unobservable Input	Range (per Bbl)
Embedded commodity derivative	$ 22,068	Option model	Future prices of NYMEX crude oil after December 31, 2021	$82.02 - $97.88

Sensitivity to Changes In Significant Unobservable Inputs. As presented in the table above, the significant unobservable inputs used in the fair value measurement of Whiting's embedded commodity derivative within its CO2 purchase contract are the future prices of NYMEX crude oil from January 2022 to December 2029. Significant increases (decreases) in these unobservable inputs in isolation would result in a significantly lower (higher) fair value asset 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. The Company did not recognize any impairment write-downs with respect to its proved oil and gas properties during the 2014 or 2013 reporting periods presented.

8. DEFERRED COMPENSATION

Production Participation Plan—The Company has a Production Participation Plan (the "Plan") in which all employees participate. On an annual basis, interests in oil and gas properties acquired, developed or sold during the year are allocated to the Plan as determined annually by the Compensation Committee of the Company's Board of Directors. Once allocated, the interests (not legally conveyed) are fixed. Interest allocations prior to 1995 consisted of 2%-3% overriding royalty interests. Interest allocations since 1995 have been 1.75%-5% of oil and gas sales less lease operating expenses and production taxes.

Payments of 100% of the year's Plan interests to employees and the vested percentages of former employees in the year's Plan interests are made annually in cash after year-end. Accrued compensation expense under the Plan for the three months ended March 31, 2014 and 2013 amounted to $10.9 million and $10.3 million, respectively, charged to general and administrative expense and $1.1 million and $1.0 million, respectively, charged to exploration expense.

Employees vest in the Plan ratably at 20% per year over a five-year period. Pursuant to the terms of the Plan, (i) employees who terminate their employment with the Company are entitled to receive their vested allocation of future Plan year payments on an annual basis; (ii) employees will become fully vested at age 62, regardless of when their interests would otherwise vest; and (iii) any forfeitures inure to the benefit of the Company.

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At March 31, 2014, the Company used three-year average historical NYMEX prices of $95.89 per Bbl for crude oil and $3.51 per Mcf for natural gas to estimate this liability. The Company records the expense associated with changes in the present value of estimated future payments under the Plan as a separate line item in the consolidated statements of income. If the Company were to terminate the Plan or upon a change in control of the Company (as defined in the Plan), all employees fully vest and the Company would 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 or within one month after a change in control event. Based on current strip prices at March 31, 2014, if the Company elected to terminate the Plan or if a change of control event occurred, it is estimated that the fully vested lump sum cash payment to employees would approximate $134.0 million. This amount includes $18.6 million attributable to proved undeveloped oil and gas properties and $12.0 million relating to the short-term portion of the

Plan liability, which has been reflected as a current payable in accrued liabilities and other, to be paid in January and February of 2015. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control.

Table of Contents

The following table presents changes in the Plan's estimated long-term liability (in thousands):

Long-term Production Participation Plan liability at January 1, 2014	$87,503
Change in liability for accretion, vesting, changes in estimates and new Plan year activity	15,658
Accrued compensation expense reflected as a current liability	(12,022)
Long-term Production Participation Plan liability at March 31, 2014	$91,139

9. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

6.25% Convertible Perpetual Preferred Stock—In June 2009, the Company completed a public offering of 6.25% convertible perpetual preferred stock ("preferred stock"), selling 3,450,000 shares at a price of $100.00 per share. As a result of voluntary conversions and the Company exercising its right to mandatorily convert shares of preferred stock effective June 27, 2013, all 172,129 shares of preferred stock outstanding on March 31, 2013 were converted into 792,919 shares of common stock. As of March 31, 2014, no shares of preferred stock remained issued or outstanding.

Each holder of the preferred stock was entitled to an annual dividend of $6.25 per share to be paid quarterly in cash, common stock or a combination thereof on March 15, June 15, September 15 and December 15, once such dividend had been declared by Whiting's board of directors.

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. As of March 31, 2014, 4,870,475 shares of common stock remained available for grant under the 2013 Equity Plan.

For the three months ended March 31, 2014 and 2013, total stock compensation expense recognized for restricted share awards and stock options was $6.7 million in each period.

Restricted Shares. Restricted stock awards for executive officers and employees generally vest ratably over a three-year service period, while awards to directors generally vest ratably over a one or three-year service period. The Company uses historical data and projections to estimate expected employee behaviors related to restricted stock forfeitures. The expected forfeitures are then included as part of the grant date estimate of compensation cost. For service-based restricted stock awards, the grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date.

In January 2014 and 2013, 750,681 shares and 751,872 shares, respectively, of restricted stock, subject to certain market-based vesting criteria in addition to the standard three-year service condition, were granted to executive officers under the Equity Plan. Vesting each year is subject to the condition that Whiting's stock price increases by a greater percentage (or decreases by a lesser percentage) than the average percentage increase (or decrease, respectively) of the stock prices of a peer group of companies. The market-based conditions must be met in order for the stock awards to vest, and it is therefore possible that no shares could vest in one or more of the three-year vesting periods. However, the Company recognizes compensation expense for awards subject to market conditions regardless of whether it becomes probable that these conditions will be achieved or not, and compensation expense is not reversed if vesting does not actually occur.

Table of Contents

For these awards subject to market conditions, the grant date fair value was estimated using a Monte Carlo valuation model. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility was calculated based on the historical volatility of Whiting's common stock, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with the three-year vesting period. The key assumptions used in valuing the market-based restricted shares were as follows:

	2014	2013
Number of simulations	65,000	65,000
Expected volatility	42.3%	43.1%
Risk-free rate	0.86%	0.41%
Dividend yield	-	-

The grant date fair value of the market-based restricted stock as determined by the Monte Carlo valuation model was $26.59 per share and $23.01 per share in January 2014 and 2013, respectively.

The following table shows a summary of the Company's nonvested restricted stock as of March 31, 2014, as well as activity during the three months then ended:

	Number of Shares	Weighted Average Grant Date Fair Value
Restricted stock awards nonvested, January 1, 2014	1,444,310	$ 31.71
Granted	893,934	31.80
Vested	(485,626)	31.32
Forfeited	(197,433)	42.73
Restricted stock awards nonvested, March 31, 2014	1,655,185	$ 30.55

As of March 31, 2014, there was $32.6 million of total unrecognized compensation cost related to unvested restricted stock granted under the stock incentive plans. That cost is expected to be recognized over a weighted average period of 2.4 years.

Stock Options. Stock options may be granted to certain executive officers of the Company with exercise prices equal to the closing market price of the Company's common stock on the grant date. There were no stock options granted under either the 2003 Equity Plan or the 2013 Equity Plan during 2013 or the first quarter of 2014. The Company's stock options vest ratably over a three-year service period from the grant date and are exercisable immediately upon vesting through the tenth anniversary of the grant date.

The following table shows a summary of the Company's stock options outstanding as of March 31, 2014 as well as activity during the three months then ended:

Table of Contents

	Number of Options	Weighted Average Exercise Price per Share	Aggregate Intrinsic Value (in thousands)	Weighted Average Remaining Contractual Term (in years)
Options outstanding at January 1, 2014	420,840	$ 28.65		
Granted	-	-		
Exercised	(2,572)	34.31	$ 83.5	
Forfeited or expired	-	-		
Options outstanding at March 31, 2014	418,268	$ 28.62	$ 17,054.1	5.7
Options vested and expected to vest at March 31, 2014	418,268	$ 28.62	$ 17,054.1	5.7
Options exercisable at March 31, 2014	403,147	$ 27.77	$ 16,779.3	5.6

Unrecognized compensation cost as of March 31, 2014 related to unvested stock option awards was $0.1 million, which is expected to be recognized over a period of 0.8 years.

Noncontrolling Interest—The 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):

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
Balance at January 1	$8,132	$8,184
Net income (loss)	(18)	(19)
Balance at March 31	$8,114	$8,165

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 months ended March 31, 2014 and 2013 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 per share are as follows (in thousands, except per share data):

22

Table of Contents

	Three Months Ended March 31, 2014	2013
Basic Earnings Per Share		
Numerator:		
Net income available to shareholders	$109,069	$86,263
Preferred stock dividends	-	(269)
Net income available to common shareholders, basic	$109,069	$85,994
Denominator:		
Weighted average shares outstanding, basic	118,923	117,788
Diluted Earnings Per Share		
Numerator:		
Net income available to common shareholders, basic	$109,069	$85,994
Preferred stock dividends	-	269
Adjusted net income available to common shareholders, diluted	$109,069	$86,263
Denominator:		
Weighted average shares outstanding, basic	118,923	117,788
Restricted stock and stock options	1,008	682
Convertible perpetual preferred stock	-	793
Weighted average shares outstanding, diluted	119,931	119,263
Earnings per common share, basic	$0.92	$0.73
Earnings per common share, diluted	$0.91	$0.72

For the three months ended March 31, 2014, the diluted earnings per share calculation excludes the dilutive effect of 32,356 incremental shares of restricted stock that did not meet its market-based vesting criteria. For the three months ended March 31, 2013, the diluted earnings per share calculation excludes (i) the dilutive effect of 171,682 incremental shares of restricted stock that did not meet its market-based vesting criteria as of March 31, 2013, and (ii) the dilutive effect of 312 common shares for stock options that were out-of-the-money.

12. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In February 2013, the FASB issued Accounting Standards Update No. 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date ("ASU 2013-04"). The objective of ASU 2013-04 is to provide guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date. ASU 2013-04 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Company adopted ASU 2013-04 effective January 1, 2014, which did not have an impact on the Company's consolidated financial statements.

In July 2013, the FASB issued Accounting Standards Update No. 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists ("ASU 2013-11"). The objective of ASU 2013-11 is to provide guidance on financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. ASU 2013-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Company adopted ASU 2013-11 effective January 1, 2014, which did not have an impact on the Company's consolidated financial statements, other than insignificant balance sheet reclassifications.

23

Table of Contents

13. SUBSEQUENT EVENT

In April 2014, Whiting Oil and Gas entered into an amendment to its existing credit agreement to extend the principal repayment date from April 2016 to the earlier of (i) April 2, 2019 or (ii) with certain exceptions, the date that is 91 days prior to the scheduled maturity of any permitted additional unsecured senior or senior subordinated notes, which includes the Company's 5% Senior Notes due March 2019, unless redeemed earlier in accordance with the credit agreement.

Table of Contents

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 Whiti Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in exploration, development, acquisition and production activities primarily in the Rocky Mountains and Permian Basin regions of the United States. Prior to 2006, we generally emphasized the acquisition of properties that increased our production levels and provided upside potential through further development. Since 2006, we have focused primarily 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. 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 believe to be the most advantageous investments.

As demonstrated by our recent capital expenditure programs, we are increasingly focused on a balanced exploration and development program, while continuing to selectively pursue acquisitions that complement our existing core properties. We 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;
- allocating a portion of our exploration and development budget to leasing and exploring prospect areas;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows; and
- seeking property acquisitions that complement our core areas.

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.

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. 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 2012:

25

Table of Contents

	2012				2013				2014
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
Crude oil	$102.94	$93.51	$92.19	$88.20	$94.34	$94.23	$105.82	$97.50	$98.62
Natural gas	$2.72	$2.21	$2.81	$3.41	$3.34	$4.10	$3.58	$3.60	$4.93

Lower oil 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 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 and 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. Alternatively, 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.

2014 Highlights and Future Considerations

Operational Highlights.

Sanish and Parshall Fields. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations. Net production in the Sanish and Parshall fields averaged 40.6 MBOE/d for the first quarter of 2014, representing a slight increase from 40.4 MBOE/d in the fourth quarter of 2013. As of March 31, 2014, we had four drilling rigs active in the Sanish field. Based on the success of our high density pilot programs in the Sanish field, we plan to commence a development program drilling nine wells per spacing unit in the area, an increase over our original plan of three to four wells per spacing unit.

Lewis & Clark/Pronghorn Fields. Our Lewis & Clark/Pronghorn fields are located primarily in the Stark and Billings counties of North Dakota and run along the Bakken shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Pronghorn Sand and Three Forks formations (Middle Bakken and Lower Bakken Shale is absent). Net production in the Lewis & Clark/Pronghorn fields averaged 13.7 MBOE/d in the first quarter of 2014, which represents a 9% decrease from 15.1 MBOE/d in the fourth quarter of 2013. This decrease in production between periods is primarily the result of wells in these fields being temporarily shut-in to protect the wellbore while nearby wells are undergoing the fracture stimulation process. As of March 31, 2014, we had four drilling rigs operating in the Pronghorn field, all of which are utilizing drilling pads, with two or three wells from each pad. Additionally, we have tested our new completion design in the Pronghorn field utilizing cemented liners and plug-and-perf technology and are encouraged by the results. As a result of these successes, we plan to use this completion procedure on all wells drilled in the area.

We have completed the construction of our gas processing plant located south of Belfield, North Dakota, which primarily processes production from the Pronghorn area. In November 2012, we began connecting other operators' wells to the plant, and we added inlet compression during 2013 in order to fully utilize the plant's processing capability. Currently, there is inlet compression in place to process 35 MMcf/d, and as of March 31, 2014 the plant was processing over 16 MMcf/d. In May 2012, we sold a 50% ownership interest in the plant, gathering systems and related facilities. We retained a 50% ownership interest and continue to operate the Belfield plant and facilities.

Hidden Bench/Tarpon Fields. Our Hidden Bench and Tarpon fields in McKenzie County, North Dakota target the Bakken and Three Forks formations. In the first quarter of 2014, net production from the Hidden Bench/Tarpon fields averaged 13.3 MBOE/d, which is relatively consistent with production of 13.4 MBOE/d in the fourth quarter of 2013. We have also implemented our new completion design at our Hidden Bench field, utilizing cemented liners and plug-and-perf technology, and the new design has generated positive results which include improved initial production rates. Based on the success of our high density drilling pilot at the Hidden Bench field, we plan to commence a development program drilling eight wells per spacing unit in the area, an increase over our original plan of four wells per spacing unit. In the Tarpon field, we have drilled six productive wells as of March 31, 2014 and are currently drilling additional wells in this area.

Table of Contents

Missouri Breaks Field. Our Missouri Breaks field, which is located in Richland County, Montana and McKenzie County, North Dakota, targets the Middle Bakken formation. In the first quarter of 2014, net production from the Missouri Breaks field averaged 3.6 MBOE/d, representing a 7% decrease from 3.8 MBOE/d in the fourth quarter of 2013. This decrease in production between periods is primarily the result of wells in this field being temporarily shut-in to protect the wellbore while nearby wells are undergoing the fracture stimulation process. We have implemented our new completion design at this field, utilizing cemented liners, plug-and-perf technology and higher sand volumes, and the new design has improved initial production rates. In addition, we recently completed a well using our new coiled tubing fracture stimulation method and are encouraged by the initial results. We have drilled successful wells on the western, eastern and southern portions of our acreage in this area.

Redtail Field. Our Redtail field in the Denver Julesberg Basin ("DJ Basin") in Weld County, Colorado targets the Niobrara formation. In the first quarter of 2014, net production from the Redtail field averaged 4.6 MBOE/d, representing at 41% increase from 3.2 MBOE/d in the fourth quarter of 2013. Our development plan at Redtail currently includes drilling up to eight Niobrara "B" wells per spacing unit and eight Niobrara "A" wells per spacing unit. In 2014, we plan to test a high-density pattern in the Niobrara "A", "B" and "C" zones drilling 32 wells per spacing unit. As of March 31, 2014, we had three drilling rigs operating in this area, and we plan to add another rig in the second half of 2014. We implemented a new completion design in this field, utilizing larger proppant volumes, which has been yielding improved production results, and we are currently evaluating the use of cemented liners in the Redtail field.

The associated gas that is produced along with the Niobrara crude oil from our Redtail field must be processed before being sold. In April 2014, we completed the construction of and brought online a gas processing plant for this area. The plant's inlet capacity is 20 MMcf/d, and we plan to further expand the plant's capacity to 70 MMcf/d in the first quarter of 2015.

North Ward Estes Field. The North Ward Estes field is located in the Ward and Winkler counties in Texas, and we continue to have significant development and related infrastructure activity in this field 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 been responding positively to the water and CO_2 floods that we initiated in May 2007. We are currently injecting CO_2 in one of the largest phases of our eight-phase project at North Ward Estes, and several of the phases of the CO_2 flood are continuing to respond. Net production from North Ward Estes averaged 9.8 MBOE/d for the first quarter of 2014, which is consistent with this field's production in the fourth quarter of 2013. As of March 31, 2014, we were injecting approximately 400 MMcf/d of CO_2 into the field, over half of which is recycled.

Acquisition and Divestiture Highlights.

In March 2014, we completed the sale of approximately 49,900 gross (41,000 net) acres, which consisted mainly of undeveloped acreage as well as our interests in certain producing oil and gas wells, in our Big Tex prospect located in the Delaware Basin of Texas for a cash purchase price of $76.2 million (subject to post-closing adjustments) resulting in a pre-tax gain on sale of $11.9 million. With this divestiture, we no longer own any interests in the Big Tex prospect.

Table of Contents

Results of Operations

Three Months Ended March 31, 2014 Compared to Three Months Ended March 31, 2013

	Three Months Ended March 31,	
	2014	2013
Net production:		
Oil (MMBbl)	7.2	6.3
NGLs (MMBbl)	0.6	0.7
Natural gas (Bcf)	6.7	6.4
Total production (MMBOE)	9.0	8.0
Net sales (in millions):		
Oil (1)	$643.4	$550.7
NGLs	34.3	30.2
Natural gas (1)	43.6	24.2
Total oil, NGL and natural gas sales	$721.3	$605.1
Average sales prices:		
Oil (per Bbl)	$88.85	$88.11
Effect of oil hedges on average price (per Bbl)	(0.10)	(0.85)
Oil net of hedging (per Bbl)	$88.75	$87.26
Average NYMEX price (per Bbl)	$98.62	$94.34
NGLs (per Bbl)	$52.95	$42.56
Natural gas (per Mcf)	$6.50	$3.80
Average NYMEX price (per Mcf)	$4.93	$3.34
Cost and expenses (per BOE):		
Lease operating expenses	$12.75	$12.45
Production taxes	$6.67	$6.39
Depreciation, depletion and amortization expense	$26.12	$25.08
General and administrative expenses	$3.59	$3.60

(1) Before consideration of hedging transactions.

Oil, NGL and Natural Gas Sales. Our oil, NGL and natural gas sales revenue increased $116.1 million to $721.3 million when comparing the first quarter of 2014 to the same period in 2013. Sales revenue is a function of oil, NGL and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 16%, and our natural gas sales volumes increased 5% between periods, while our NGL sales volumes decreased 9% between periods. The oil volume increase resulted primarily from drilling success at our Hidden Bench/Tarpon, Sanish and Parshall, Redtail and Missouri Breaks fields. During the first quarter of 2014, oil production from our Hidden Bench/Tarpon fields increased 710 MBbl, oil production from our Sanish and Parshall fields increased 395 MBbl, oil production from our Redtail field increased 290 MBbl and oil production from our Missouri Breaks field increased 130 MBbl over the same period in 2013. These production increases were partially offset by the sale of our Postle field, which had oil production of 590 MBbl in the first quarter of 2013 but which was fully divested in July 2013. 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 435 MMcf at our Hidden Bench/Tarpon fields and 415 MMcf at our Sanish and Parshall fields. These gas volume increases were largely offset by normal field production decline across several of our areas, the most notable of which were our Flat Rock and Anterim fields where production volumes decreased 165 MMcf and 115 MMcf, respectively, when comparing the first quarter of 2014 to the same period in 2013. The NGL volume decrease between periods was primarily due to the sale of our Postle field, which occurred in July 2013.

Table of Contents

In addition to the above crude oil and natural gas production-related increases in net revenue were increases in the average sales prices realized for oil, NGLs and natural gas in the first quarter of 2014 compared to 2013. Our average price for oil before the effects of hedging increased 1%, our average price for NGLs increased 24%, and our average price for natural gas increased 71% between periods.

Gain on Sale of Properties. During the first quarter 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 $76.2 million in cash, which resulted in a pre-tax gain on sale of $11.9 million. There were no other property divestitures resulting in a significant gain or loss on sale during the first quarter of 2014 or 2013.

Lease Operating Expenses. Our lease operating expenses ("LOE") during the first quarter of 2014 were $114.8 million, a $14.9 million increase over the same period in 2013. Higher LOE in 2014 were primarily related to a $12.9 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months, as well as a higher level of workover activity. Workovers increased from $19.8 million in the first quarter of 2013 to $21.8 million in the first quarter of 2014, primarily due to a higher number of well workovers being conducted at our Sanish and Parshall fields and at our CO2 project at North Ward Estes, partially offset by a lower number of well workovers at our Postle field which we sold in July 2013.

Our lease operating expenses on a BOE basis also increased during the first quarter of 2014. LOE per BOE amounted to $12.75 during the first quarter of 2014, which was up from $12.45 per BOE during the first quarter of 2013. This increase was mainly due to the higher costs of oil field goods and services and an increase in well workover costs in 2014, as discussed above, partially offset by higher overall production volumes between periods.

Production Taxes. Our production taxes during the first quarter of 2014 were $60.0 million, an $8.8 million increase over the same period in 2013, which increase was primarily due to higher 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 8.3% and 8.5% for the first quarter of 2014 and 2013, respectively.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $34.1 million in 2014 as compared to the first quarter of 2013. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended March 31,	
	2014	2013
Depletion	$230,953	$196,823
Depreciation	1,216	1,083
Accretion of asset retirement obligations	3,096	3,253
Total	$235,265	$201,159

DD&A increased in the first quarter of 2014 primarily due to $34.1 million in higher depletion expense between periods. Of this increase, $25.2 million related to an increase in our overall production volumes during the first quarter of 2014 and $8.9 million related to a higher depletion rate between periods. On a BOE basis, our overall DD&A rate of $26.12 for the first quarter of 2014 was 4% higher than the rate of $25.08 for the same period in 2013 due to $2,409.5 million in drilling and development expenditures during the past twelve months, which were partially offset by reserve additions over this same time period.

29

Table of Contents

Exploration and Impairment Costs. Our exploration and impairment costs increased $4.8 million in the first quarter of 2014 as compared to the same period in 2013. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended March 31,	
	2014	2013
Exploration	$24,122	$18,866
Impairment	17,985	18,414
Total	$42,107	$37,280

Exploration costs increased $5.3 million during the first quarter of 2014 as compared to the same period in 2013 primarily due to higher exploratory dry hole expenses. Exploratory dry hole costs for the first quarter of 2014 totaled $3.6 million, primarily related to one exploratory dry hole drilled in the Rocky Mountains region. During the first quarter of 2013, on the other hand, we drilled no exploratory dry holes.

Impairment expense in the first quarter of 2014 and 2013 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and such amortization resulted in impairment expense of $17.9 million in the first quarter of 2014 as compared to $18.3 million in the first quarter of 2013.

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

	Three Months Ended March 31,	
	2014	2013
General and administrative expenses	$61,670	$55,072
Reimbursements and allocations	(29,336)	(26,187)
General and administrative expense, net	$32,334	$28,885

General and administrative expense before reimbursements and allocations increased $6.6 million during the first quarter of 2014 as compared to the same period in 2013 primarily due to higher employee compensation. Employee compensation increased $4.4 million in the first quarter of 2014 as compared to the same period in 2013 due to personnel hired during the past twelve months and general pay increases. However, our general and administrative expenses as a percentage of oil, NGL and natural gas sales decreased slightly from 5% in the first quarter of 2013 to 4% for the first quarter of 2014.

The increase in reimbursements and allocations for the first quarter of 2014 was primarily caused by higher salary costs and a greater number of field workers on Whiting-operated properties.

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

	Three Months Ended March 31,	
	2014	2013
Senior Notes and Senior Subordinated Notes	$36,343	$10,062
Credit agreement	1,122	9,272
Amortization of debt issue costs and debt premium	5,360	2,435

Other	25	23
Capitalized interest	(706)	(322)
Total	$42,144	$21,470

Table of Contents

The increase in interest expense of $20.7 million between periods was mainly attributable to $26.3 million in higher interest costs incurred on our notes during 2014 and a $2.9 million increase in amortization of debt issue costs on our notes during the first quarter of 2014 as compared to the first quarter of 2013. These increases are due to our September 2013 issuance of $1,100.0 million of 5% Senior Notes due 2019 and $1,200.0 million of 5.75% Senior Notes due 2021. These increases were partially offset by an $8.2 million decrease in the amount of interest incurred on our credit agreement during the first quarter of 2014 as compared to the first quarter of 2013 due to lower borrowings outstanding under this facility in 2014. Our weighted average debt outstanding during the first quarter of 2014 was $2,650.0 million versus $2,028.1 million for the first quarter of 2013. Our weighted average effective cash interest rate was 5.7% during the first quarter of 2014 compared to 3.8% for the first quarter of 2013.

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 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 $24.5 million for the three months ended March 31, 2014 mainly due to the upward shift in the futures curve of forecasted commodity prices (“forward price curve”) for crude oil from January 1, 2014 (or the 2014 date on which new contracts were entered into) to March 31, 2014. Commodity derivative loss, net for the three months ended March 31, 2013 resulted in a loss of $31.3 million due to the more significant upward shift in the same forward price curve from January 1, 2013 (or the 2013 date on which prior year contracts were entered into) to March 31, 2013.

See Item 3, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding derivatives as of April 1, 2014.

Income Tax Expense. Income tax expense totaled $76.4 million for the first quarter of 2014 as compared to $51.5 million of income tax for the first quarter of 2013, an increase of $24.8 million that was mainly related to $47.6 million in higher pre-tax income between periods.

Our effective tax rates for the periods ending March 31, 2014 and 2013 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 increased from 37.4% for the first quarter of 2013 to 41.2% for the first quarter of 2014. This increase is a result of increased apportionment to states with higher tax rates and additional tax expense for restricted stock awards that did not vest.

Liquidity and Capital Resources

Overview. At March 31, 2014, we had $406.4 million of cash on hand and $3,933.4 million of equity, while at December 31, 2013, we had $699.5 million of cash on hand and $3,828.6 million 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 derivative contracts. Oil accounted for 80% and 78% of our total production in the first quarter of 2014 and 2013, respectively. As a result, our operating cash flows are more sensitive to fluctuations in the price for crude oil than to fluctuations in the price for NGLs and natural gas. As of April 1, 2014, we had derivative contracts covering the sale of approximately 49% of our forecasted oil production volumes for the remainder of 2014.

During the first quarter of 2014, we generated $323.9 million of cash provided by operating activities, an increase of $26.3 million over the same period in 2013. Cash provided by operating activities increased primarily due to higher realized sales prices for oil, NGLs and natural gas and higher crude oil and natural gas production volumes during the first quarter of 2014. These positive factors were partially offset by increased lease operating expenses, production taxes, exploration costs, general and administrative and cash interest expense in the first quarter of 2014 as compared to the same period in 2013. Refer to “Results of Operations” for more information on the impact of prices and volumes on revenues and for more information on increases and decreases in certain expenses during the first quarter of 2014.

Table of Contents

During the first quarter of 2014, cash flows from operating activities and cash on hand plus $75.0 million of proceeds from the sale of properties were used to finance $596.4 million of drilling and development expenditures, $33.7 million of oil and gas property acquisitions, $26.4 million for the final payment under our Tax Sharing and Indemnification Agreement with Alliant Energy Corporation and $24.5 million for purchases of other property and equipment.

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

	Three Months Ended March 31,	
	2014	2013
Rocky Mountains	$563,553	$453,191
Permian Basin (1)	109,067	87,030
Other (2)	10,773	29,063
Total incurred	$683,393	$569,284

(1) For the three months ended March 31, 2014 and 2013, amount includes $10.4 million and $0.7 million, respectively, related to the development of CO_2 reserves at our Bravo Dome field in New Mexico.
(2) Other primarily includes oil and gas properties in Arkansas, Louisiana, Michigan, Oklahoma and Texas.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2014 exploration and development budget is $2.7 billion, which we expect to fund substantially with net cash provided by our operating activities, cash on hand and borrowings under our credit facility. This represents a slight increase from the $2,675.2 million incurred on exploration, development and acreage expenditures during 2013, and based on this level of capital spending, we are forecasting production growth in 2014 over our 2013 production level of 34.3 MMBOE. We expect to allocate $2,433.0 million of our 2014 budget to exploration and development activity, $116.0 million for undeveloped acreage and $151.0 million for facilities. Although we have only budgeted $116.0 million for undeveloped leasehold purchases in 2014, 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 $2.7 billion, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, 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. In addition, 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 Corporation ("Whiting Oil and Gas"), our wholly-owned subsidiary, has a credit agreement with a syndicate of banks that as of March 31, 2014 had a borrowing base of $2.8 billion, of which $1.2 billion has been committed by lenders and is available for borrowing. We may increase the maximum aggregate amount of commitments under the credit agreement up to the $2.8 billion borrowing base if certain conditions are satisfied, including the consent of lenders participating in the increase. As of March 31, 2014, we had $1,197.0

million of available borrowing capacity, which was net of $3.0 million in letters of credit and no borrowings outstanding. In April 2014, Whiting Oil and Gas entered into an amendment to its credit agreement that extended the principal repayment date from April 2016 to the earlier of (i) April 2, 2019 or (ii) with certain exceptions, the date that is 91 days prior to the scheduled maturity of any permitted additional unsecured senior or senior subordinated notes, which includes the Company's 5% Senior Notes due March 2019, unless redeemed earlier in accordance with the credit agreement.

Table of Contents

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. A portion of the revolving credit facility in an aggregate amount not to exceed $50.0 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 March 31, 2014, $47.0 million was available for additional letters of credit under the agreement.

The amended credit agreement provides for interest only payments until the expiration date of the agreement, when all outstanding borrowings are due. Interest 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 0.50% or an adjusted LIBOR rate plus 1.00%, 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 lesser of the aggregate commitments of the lenders or the borrowing base.

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 Whiting Oil and Gas. The credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.0 to 1.0 and (ii) 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. We were in compliance with our covenants under the credit agreement as of March 31, 2014.

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 September 2013, we issued at par $1,100.0 million of 5% Senior Notes due March 2019 and $800.0 million of 5.75% Senior Notes due March 2021, and also in September 2013, we issued at 101% of par an additional $400.0 million of 5.75% Senior Notes due March 2021. In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018.

The indentures governing the notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. Additionally, the indentures governing the notes contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, 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 March 31, 2014. 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.

Table of Contents

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liability of \$103.2 million (which amount comprises both the long and short-term portions of this obligation) as of March 31, 2014, since we cannot determine with accuracy the timing or amounts of future payments other than the short-term portion of \$12.0 million. The table below also does not include any penalties that may be incurred under our physical delivery contracts, since we cannot predict with accuracy whether we will be subject to any such penalties or the amount and timing of any such penalties if incurred. The following table summarizes our obligations and commitments as of March 31, 2014 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (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)	$2,650,000	$-	$-	$1,450,000	$1,200,000
Cash interest expense on debt (2)	855,208	146,750	293,500	279,833	135,125
Derivative contract liability fair value (3)	11,799	11,799	-	-	-
Asset retirement obligations (4)	153,345	7,156	14,143	16,579	115,467
Purchase obligations (5)	618,096	94,154	217,666	104,895	201,381
Drilling rig contracts (6)	118,621	80,334	38,287	-	-
Operating leases (7)	27,252	6,301	11,002	8,858	1,091
Construction and drilling contract (8)	39,586	25,686	2,900	11,000	-
Total	$4,473,907	$372,180	$577,498	$1,871,165	$1,653,064

(1) Long-term debt consists of the principal amounts of the 6.5% Senior Subordinated Notes due 2018, the 5% Senior Notes due 2019 and the 5.75% Senior Notes due 2021.

(2) Cash interest expense on the 6.5% Senior Subordinated Notes due 2018, the 5% Senior Notes due 2019 and the 5.75% Senior Notes due 2021 is estimated assuming no principal repayment until the due dates of the instruments. No cash interest expense is assumed on the credit facility as there were no borrowings outstanding as of March 31, 2014.

(3) The above derivative obligation at March 31, 2014 primarily consists of (i) an \$11.7 million fair value liability for derivative contracts we have entered into on our own behalf, primarily in the form of costless collars, to hedge our exposure to crude oil price fluctuations and (ii) a \$0.1 million payable to Trust II for derivative contracts that we have entered into but have in turn conveyed to Trust II (although these derivatives are in a fair value asset position at quarter end, 90% of such derivative assets are due to Trust II under the terms of the conveyance). With respect to only a portion of our open derivative contracts at March 31, 2014 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 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 risk and commodity price volatility.

(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, one agreement expiring in December 2014, one agreement expiring in December 2017 and one agreement expiring in December 2029, whereby we have committed to buy certain volumes of CO2 for use in our North Ward Estes EOR project in Texas. The purchase agreements are with two different suppliers. Under the terms of the agreements, we are obligated to purchase a minimum daily volume of CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. In addition, we have one ship-or-pay agreement expiring in December 2017, whereby we have committed to transport a minimum daily volume of CO2 via a certain pipeline or else pay for any deficiencies at a price stipulated in the contract. The CO2 volumes planned for use in the EOR project in the North Ward Estes field currently exceed the minimum daily volumes specified in all of these agreements. Therefore, we expect to avoid any payments for deficiencies. The purchasing obligations reported above represent our minimum financial commitment pursuant to the terms of these contracts. However, our actual expenditures under these contracts are expected to exceed the minimum commitments presented above.

Table of Contents

(6) We currently have 11 drilling rigs under long-term contract, of which five drilling rigs expire in 2014, three in 2015 and three in 2016. All of these rigs are operating in the Rocky Mountains region. As of March 31, 2014, early termination of the remaining contracts would require termination penalties of $84.4 million, which would be in lieu of paying the remaining drilling commitments of $118.6 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(7) We lease 172,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2018, 47,900 square feet of office space in Midland, Texas expiring in 2020 and 20,000 square feet of office space in Dickinson, North Dakota expiring in 2016. In addition, we entered into a lease for several residential apartments in Watford City and Dickinson, North Dakota under an operating lease agreement expiring in 2015.

(8) We entered into a contractual obligation to spend up to $51.4 million on the construction of certain facilities and field infrastructure and the drilling of forty-six CO_2 wells in our Bravo Dome field. If we fail to spend the required amounts by the dates set forth in the agreement, we will be required to pay the remaining unspent capital expenditures as liquidated damages. However, we expect to fulfill our obligations under this contract and thereby avoid any payments for deficiencies. We do not have any volumetric CO_2 delivery or supply commitments associated with this contract.

Based on current oil and natural gas prices and anticipated levels of production, we believe that the estimated net cash generated from operations, together with cash on hand and amounts available under our credit agreement, will be adequate to meet future liquidity needs, including satisfying our financial obligations and funding our operations and exploration and development activities.

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to 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, 2013.

Effects of Inflation and Pricing

We experienced increased costs during 2013 and the first quarter of 2014 due to increased demand for oil field 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.

Table of Contents

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; 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; impacts to financial statements as a result of impairment write-downs; risks related to our level of indebtedness and periodic redeterminations of the borrowing base under our credit agreement; 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; our ability to successfully complete potential asset dispositions and the risks related thereto; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; 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 in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption “Risk Factors” in our Annual Report on Form 10-K for the period ended December 31, 2013. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this Quarterly Report on Form 10-Q.

Table of Contents

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, 2013 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, 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 quarter of 2014, our income before income taxes for the three months ended March 31, 2014 would have moved up or down $64.3 million for each 10% change in oil prices per Bbl, $3.4 million for each 10% change in NGL prices per Bbl and $4.4 million for each 10% change in natural gas prices per Mcf.

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

Commodity Derivative Contracts—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. Consequently, 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 March 31, 2014, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of March 31, 2014 would cause a decrease or increase, respectively, of $71.3 million in our commodity derivative loss.

Our outstanding hedges as of April 1, 2014 are summarized below:

Whiting Petroleum Corporation

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Three-way collars (1)	Crude Oil	04/2014 to 06/2014	1,380,000	$71.23/$85.36/$103.54
	Crude Oil	07/2014 to 09/2014	1,380,000	$71.23/$85.36/$103.54
	Crude Oil	10/2014 to 12/2014	1,380,000	$71.23/$85.36/$103.54

(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.

Fixed-differential Crude Oil Contract. We have entered into a fixed-differential crude oil sales and delivery contract for oil volumes we plan to produce from the Niobrara in Colorado. The table below summarizes the future production volumes to be sold under this contract as of April 1, 2014 at a price equal to NYMEX less a fixed-differential of $4.75 per Bbl:

Commodity	Period	Average Daily Volume (Bbl per day)
Crude Oil	01/2015 to 12/2015	25,000
Crude Oil	01/2016 to 12/2016	30,000
Crude Oil	01/2017 to 12/2017	35,000
Crude Oil	01/2018 to 12/2018	40,000
Crude Oil	01/2019 to 12/2019	45,000

Table of Contents

Fixed-price Natural Gas Contracts. We have various fixed-price gas sales contracts with end users for a portion of the natural gas we produce in Colorado and Utah. Our future production volumes projected to be sold under these fixed-price contracts as of April 1, 2014 are summarized below:

Commodity	Period	Average Daily Volume (MMBtu per day)	Weighted Average Price Per MMBtu
Natural Gas	04/2014 to 06/2014	11,000	$5.49
Natural Gas	07/2014 to 09/2014	11,000	$5.49
Natural Gas	10/2014 to 12/2014	11,000	$5.49

Commodity Derivatives Conveyed to Whiting USA Trust II. In connection with our conveyance in March 2012 of a term net profits interest to Whiting USA Trust II ("Trust II"), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 365 MBbl of crude oil in 2014, have been conveyed to Trust II, and therefore such payments will be included in Trust II's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. This results in third-party public holders of Trust II units receiving 90%, while we retain 10%, of the future economic results of such hedges. No additional hedges are allowed to be placed on Trust II assets.

The table below summarizes all of the outstanding costless collars that we entered into and then in turn conveyed, as described in the preceding paragraph, to Trust II (of which we retain 10% of the future economic results and third-party public holders of Trust II units receive 90% of the future economic results):

Conveyed to Whiting USA Trust II

Derivative Instrument	Commodity	Period	Monthly Volume (Bbl)	NYMEX Floor/Ceiling
Collars	Crude Oil	04/2014 to 06/2014	41,500	$80.00/$122.50
	Crude Oil	07/2014 to 09/2014	40,600	$80.00/$122.50
	Crude Oil	10/2014 to 12/2014	39,700	$80.00/$122.50

Embedded Commodity Derivative Contracts—The price we pay for oil field products and services significantly impacts our profitability, reserve estimates, access to capital and future growth rate. Typically, as prices for oil and natural gas increase, so do all associated costs. In May 2011, we entered into a long-term contract to purchase CO_2 from 2015 through 2029 for use in our EOR project at the North Ward Estes field in Texas. This contract contains a price adjustment clause that is linked to changes in NYMEX crude oil prices, in order to reduce our exposure to paying higher than the market rates for CO_2 in a climate of declining oil prices. We have determined that the portion of this contract linked to NYMEX oil prices is not clearly and closely related to the host contract, and we have therefore bifurcated this embedded pricing feature from its host contract and reflected it at fair value in the consolidated financial statements. This embedded commodity derivative contract has not been designated as a hedge, and therefore all changes in fair value since inception have been recorded immediately to earnings. The price per Mcf of CO_2 purchased under this agreement increases or decreases as the average price of NYMEX crude oil likewise increases or decreases. For this embedded commodity derivative contract, a hypothetical upward or downward shift of 10% per Bbl in the NYMEX forward curve as of March 31, 2014 would cause a decrease or increase, respectively, of $8.8 million in our commodity derivative loss.

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 and Chief Executive Officer and our 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 March 31, 2014. Based upon their evaluation of these disclosures controls and procedures, the Chairman and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of March 31, 2014 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.

Table of Contents

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended March 31, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") issued an updated version of its Internal Control – Integrated Framework (the "2013 Framework"). Originally issued in 1992 (the "1992 Framework"), the framework helps organizations design, implement and evaluate the effectiveness of internal control concepts and simplify their use and application. The 1992 Framework remains available during the transition period, which extends to December 15, 2014, after which time COSO will consider it as superseded by the 2013 Framework. As of March 31, 2014, the Company continues to utilize the 1992 Framework during its transition to the 2013 Framework by the end of 2014.

Table of Contents

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, 2013. No material change to such risk factors has occurred during the three months ended March 31, 2014.

Item 6. Exhibits

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

Table of Contents

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 1st day of May, 2014.

WHITING PETROLEUM CORPORATION

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

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

By /s/ Brent P. Jensen
Brent P. Jensen
Controller and Treasurer

EXHIBIT INDEX

Exhibit Number	Exhibit Description
(4.1)	Sixth Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 2, 2014, among Whiting Petroleum Corporation, its subsidiary Whiting Oil and Gas Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other agents and lenders party thereto [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated April 2, 2014 (File No. 001-31899)].
(31.1)	Certification by the Chairman and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the 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 March 31, 2014 are filed herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of March 31, 2014 and December 31, 2013, (ii) the Consolidated Statements of Income for the Three Months Ended March 31, 2014 and 2013, (iii) the Consolidated Statements of Comprehensive Income for the Three Months Ended March 31, 2014 and 2013, (iv) the Consolidated Statements of Cash Flows for the Three Months Ended March 31, 2014 and 2013, (v) the Consolidated Statements of Equity for the Three Months Ended March 31, 2014 and 2013 and (vi) Notes to Consolidated Financial Statements.