

WHITING PETROLEUM CORP
Form 10-Q
April 29, 2011

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

FORM 10-Q

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

For the quarterly period ended March 31, 2011

or

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

For the transition period from _____ to _____

Commission file number: 001-31899
WHITING PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction
of incorporation or organization)

20-0098515
(I.R.S. Employer
Identification No.)

1700 Broadway, Suite 2300
Denver, Colorado
(Address of principal executive offices)

80290-2300
(Zip code)

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting

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company” in Rule 12b-2 of the Exchange Act. (Check one):

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

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

Number of shares of the registrant’s common stock outstanding at April 15, 2011: 117,368,706 shares.

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GLOSSARY OF CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms “we,” “us,” “our” or “ours” when used in this report 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 and other liquid hydrocarbons.

“Bcf” One billion cubic feet of natural gas.

“BOE” One stock tank barrel equivalent of oil, calculated by converting natural gas volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

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

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

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

“MBOE” - One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet of natural gas.

“MMBbl” One million Bbl.

“MMBOE” One million BOE.

“MMBtu” One million British Thermal Units.

“MMcf” One million cubic feet of natural gas.

“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.

“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.

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PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

WHITING PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS (Unaudited)
(In thousands, except share and per share data)

ASSETS	March 31, 2011	December 31, 2010
Current assets:		
Cash and cash equivalents	\$ 5,026	\$ 18,952
Accounts receivable trade, net	244,016	199,713
Prepaid expenses and other	21,242	14,878
Total current assets	270,284	233,543
Property and equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	5,955,020	5,661,619
Unproved properties	296,908	226,336
Other property and equipment	108,526	98,092
Total property and equipment	6,360,454	5,986,047
Less accumulated depreciation, depletion and amortization	(1,737,216)	(1,630,824)
Total property and equipment, net	4,623,238	4,355,223
Debt issuance costs	32,623	34,226
Other long-term assets	52,413	25,785
TOTAL ASSETS	\$ 4,978,558	\$ 4,648,777
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	\$ 70,161	\$ 35,016
Accrued capital expenditures	97,274	84,789
Accrued liabilities and other	113,770	153,062
Revenues and royalties payable	75,590	82,124
Taxes payable	26,683	30,291
Derivative liabilities	140,803	69,375
Deferred income taxes	4,001	4,548
Total current liabilities	528,282	459,205
Long-term debt	980,000	800,000
Deferred income taxes	549,248	539,071
Derivative liabilities	146,557	95,256
Production Participation Plan liability	81,081	81,524
Asset retirement obligations	77,967	76,994
Deferred gain on sale	39,679	41,460
Other long-term liabilities	24,666	23,952
Total liabilities	2,427,480	2,117,462
Commitments and contingencies		
Equity:	-	-

Preferred stock, \$0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 172,400 shares issued and outstanding as of March 31, 2011 and 172,500 shares issued and outstanding as of December 31, 2010, aggregate liquidation preference of \$17,240,000 at March 31, 2011

Common stock, \$0.001 par value, 175,000,000 shares authorized; 118,112,568 issued and 117,368,706 outstanding as of March 31, 2011, 117,967,876 issued and 117,098,506 outstanding as of December 31, 2010 (1)	118	59
Additional paid-in capital	1,543,983	1,549,822
Accumulated other comprehensive income	3,834	5,768
Retained earnings	994,810	975,666
Total Whiting shareholders' equity	2,542,745	2,531,315
Noncontrolling interest	8,333	-
Total equity	2,551,078	2,531,315
TOTAL LIABILITIES AND EQUITY	\$ 4,978,558	\$ 4,648,777

(1) All common share amounts (except par value and par value per share amounts) have been retroactively restated as of December 31, 2010 to reflect the Company's two-for-one stock split in February 2011, as described in Note 8 to these consolidated financial statements.

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME (Unaudited)
(In thousands, except per share data)

	Three Months Ended March 31,	
	2011	2010
REVENUES AND OTHER INCOME:		
Oil and natural gas sales	\$ 425,683	\$ 340,694
Gain on hedging activities	3,063	6,733
Amortization of deferred gain on sale	3,367	3,737
Interest income and other	108	106
Total revenues and other income	432,221	351,270
COSTS AND EXPENSES:		
Lease operating	71,522	60,855
Production taxes	31,644	25,098
Depreciation, depletion and amortization	107,728	97,549
Exploration and impairment	22,237	12,906
General and administrative	18,413	13,634
Interest expense	14,458	15,692
Change in Production Participation Plan liability	(443)	945
Commodity derivative (gain) loss, net	134,438	(14,923)
Total costs and expenses	399,997	211,756
INCOME BEFORE INCOME TAXES	32,224	139,514
INCOME TAX EXPENSE:		
Current	2,050	1,330
Deferred	10,760	51,573
Total income tax expense	12,810	52,903
NET INCOME	19,414	86,611
Preferred stock dividends	(270)	(5,391)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	\$ 19,144	\$ 81,220
EARNINGS PER COMMON SHARE (1):		
Basic	\$ 0.16	\$ 0.80
Diluted	\$ 0.16	\$ 0.73
WEIGHTED AVERAGE SHARES OUTSTANDING (1):		
Basic	117,243	101,822
Diluted	117,834	118,306

(1) All share and per share amounts have been retroactively restated for the 2010 period to reflect the Company's two-for-one stock split in February 2011, as described in Note 8 to these consolidated financial statements.

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(In thousands)

	Three Months Ended March 31,	
	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	\$ 19,414	\$ 86,611
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	107,728	97,549
Deferred income tax expense	10,760	51,573
Amortization of debt issuance costs and debt discount	2,127	2,866
Stock-based compensation	3,164	2,244
Amortization of deferred gain on sale	(3,367)	(3,737)
Undeveloped leasehold and oil and gas property impairments	7,638	3,843
Exploratory dry hole costs	2,902	2,010
Change in Production Participation Plan liability	(443)	945
Unrealized (gain) loss on derivative contracts	123,545	(30,220)
Other non-current	(815)	(792)
Changes in current assets and liabilities:		
Accounts receivable trade	(44,303)	(16,965)
Prepaid expenses and other	(7,861)	(4,431)
Accounts payable trade and accrued liabilities	3,708	(3,028)
Revenues and royalties payable	(6,534)	7,636
Taxes payable	(3,608)	443
Net cash provided by operating activities	214,055	196,547
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(91,525)	(15,527)
Drilling and development capital expenditures	(284,752)	(109,185)
Proceeds from sale of oil and gas properties	21	207
Issuance of note receivable	(25,000)	-
Net cash used in investing activities	(401,256)	(124,505)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Contributions from noncontrolling interest	2,500	-
Preferred stock dividends paid	(270)	(5,391)
Long-term borrowings under credit agreement	470,000	130,000
Repayments of long-term borrowings under credit agreement	(290,000)	(190,000)
Debt issuance costs	(11)	-
Restricted stock used for tax withholdings	(8,944)	(5,558)
Net cash provided by (used in) financing activities	173,275	(70,949)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(13,926)	1,093
CASH AND CASH EQUIVALENTS:		
Beginning of period	18,952	11,960
End of period	\$ 5,026	\$ 13,053

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
 CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
 (In thousands)

	Three Months Ended March 31,	
	2011	2010
NONCASH INVESTING ACTIVITIES:		
Accrued capital expenditures	\$ 97,274	\$ 38,685
NONCASH FINANCING ACTIVITIES:		
Contributions from noncontrolling interest	\$ 5,833	\$ -
See notes to consolidated financial statements.		(Concluded)

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY
AND COMPREHENSIVE INCOME (Unaudited)
(In thousands)

	Preferred Stock Shares	Amount	Common Stock(1) Shares	Amount	Additional Paid- in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Whiting Shareholders' Equity	Noncontrolling Interest	Total Equity	Compre hensive Income (Loss)
BALANCES-January 1, 2010											
	3,450	\$3	102,728	\$51	\$1,546,635	\$20,413	\$702,983	\$2,270,085	\$-	\$2,270,085	
Net income	-	-	-	-	-	-	86,611	86,611	-	86,611	\$86,611
OCI amortization on de-designated wedges, net of taxes of \$2,482	-	-	-	-	-	(4,251)	-	(4,251)	-	(4,251)	(4,251)
Total comprehensive income											\$82,360
Restricted stock issued	-	-	304	-	-	-	-	-	-	-	
Restricted stock forfeited	-	-	(6)	-	-	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(154)	-	(5,558)	-	-	(5,558)	-	(5,558)	
Stock-based compensation	-	-	-	-	2,244	-	-	2,244	-	2,244	
Preferred dividends paid	-	-	-	-	-	-	(5,391)	(5,391)	-	(5,391)	
BALANCES-March 31, 2010											
	3,450	\$3	102,872	\$51	\$1,543,321	\$16,162	\$784,203	\$2,343,740	\$-	\$2,343,740	
BALANCES-January 1, 2011											
	173	\$-	117,968	\$59	\$1,549,822	\$5,768	\$975,666	\$2,531,315	\$-	\$2,531,315	
Net income	-	-	-	-	-	-	19,414	19,414	-	19,414	\$19,414
OCI amortization on de-designated wedges, net of taxes of \$1,130	-	-	-	-	-	(1,934)	-	(1,934)	-	(1,934)	(1,934)
Total comprehensive income											\$17,480
Conversion of preferred stock to common	(1)	-	1	-	-	-	-	-	-	-	
Two-for-one stock split	-	-	-	59	(59)	-	-	-	-	-	
Contributions from noncontrolling interest	-	-	-	-	-	-	-	-	8,333	8,333	

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Restricted stock issued	-	-	293	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(3)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(147)	-	(8,944)	-	-	(8,944)	-	(8,944)
Stock-based compensation	-	-	-	-	3,164	-	-	3,164	-	3,164
Preferred dividends paid	-	-	-	-	-	-	(270)	(270)	-	(270)
BALANCES-March 31, 2011	172	\$-	118,112	\$118	\$1,543,983	\$3,834	\$994,810	\$2,542,745	\$8,333	\$2,551,078

(1) All common share amounts (except par values) have been retroactively restated for all periods presented to reflect the Company's two-for-one stock split in February 2011, as described in Note 8 to these consolidated financial statements.

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS (Unaudited)

1. BASIS OF PRESENTATION

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company that acquires, exploits, develops and explores for crude oil, natural gas and natural gas liquids primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan 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 pursuant to Whiting’s 15.8% ownership interest. 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 2010 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this 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 2010 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.

Reclassifications—In accordance with Regulation S-X Article 10, the Company has condensed certain line items within the current period financial statements, and certain prior period balances were reclassified to conform to the current year presentation accordingly. Such reclassifications had no impact on net income, working capital or equity previously reported.

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2. ACQUISITIONS

2011 Acquisitions

On March 18, 2011, Whiting and an unrelated third party formed Sustainable Water Resources, LLC (“SWR”) to develop a water project in the state of Colorado. The Company contributed \$25.0 million for a 75% interest in SWR, and the 25% noncontrolling interest in SWR was ascribed a fair value of \$8.3 million, which consisted of \$2.5 million in cash contributions, as well as \$5.8 million in tangible and intangible assets contributed to the joint venture.

On February 15, 2011, the Company completed the acquisition of 6,000 net undeveloped acres and additional working interests in the Pronghorn field in Billings and Stark Counties, North Dakota, for an aggregate purchase price of \$40.0 million and an effective date of February 1, 2011.

2010 Acquisitions

In September 2010, Whiting acquired operated interests in 19 producing oil and gas wells, undeveloped acreage, and gathering lines, all of which are located on approximately 20,400 gross (16,100 net) acres in Weld County, Colorado. The aggregate purchase price was \$19.2 million, and substantially all of it was allocated to the properties and acreage acquired.

In August 2010, Whiting acquired oil and gas leasehold interests covering approximately 112,000 gross (90,200 net) acres in the Montana portion of the Williston Basin for \$26.0 million. The undeveloped acreage is located in Roosevelt and Sheridan counties.

3. LONG-TERM DEBT

Long-term debt consisted of the following at March 31, 2011 and December 31, 2010 (in thousands):

	March 31, 2011	December 31, 2010
Credit agreement	\$380,000	\$200,000
6.5% Senior Subordinated Notes due 2018	350,000	350,000
7% Senior Subordinated Notes due 2014	250,000	250,000
Total debt	\$980,000	\$800,000

Credit Agreement—As of March 31, 2011, Whiting Oil and Gas Corporation (“Whiting Oil and Gas”), the Company’s wholly-owned subsidiary, had a credit agreement with a syndicate of banks, and this credit facility had a borrowing base of \$1.1 billion with \$718.5 million of available borrowing capacity, which was net of \$380.0 million in borrowings and \$1.5 million in letters of credit outstanding. The credit agreement provided for interest only payments until October 2015, when the agreement was to expire and all outstanding borrowings were due. In April 2011, Whiting Oil and Gas entered into an amendment to its credit agreement that decreased the interest margins on outstanding borrowings and extended the principal repayment date to April 2016. Further information on the terms of this amendment is discussed in the Subsequent Event footnote. The following is a description of the credit agreement in place as of March 31, 2011.

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 its 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, 2011, \$48.5 million was available for additional letters of credit under the agreement.

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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. The Company also incurs commitment fees of 0.50% on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base, and are included as a component of interest expense. At March 31, 2011, the weighted average interest rate on the outstanding principal balance under the credit agreement was 2.6%.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans
Less than 0.25 to 1.0	0.75%	1.75%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.00%	2.00%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.25%	2.25%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.50%	2.50%
Greater than or equal to 0.90 to 1.0	1.75%	2.75%

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, which include the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement also restricts our ability to make any dividend payments or distributions on its common stock. These restrictions apply to all of the net assets of the subsidiaries. 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 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for quarters ending March 31, 2013 and thereafter 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, 2011.

The obligations of Whiting Oil and Gas under the amended 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 Subordinated Notes—In October 2005, the Company issued at par \$250.0 million of 7% Senior Subordinated Notes due February 2014. The estimated fair value of these notes was \$266.3 million as of March 31, 2011, based on quoted market prices for these same debt securities.

In September 2010, the Company issued at par \$350.0 million of 6.5% Senior Subordinated Notes due October 2018. The estimated fair value of these notes was \$362.3 million as of March 31, 2011, based on quoted market prices for these same debt securities.

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The notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of Whiting Oil and Gas' credit agreement. The Company's obligations under the 2014 notes are fully, unconditionally, jointly and severally guaranteed by the Company's 100%-owned subsidiaries, Whiting Oil and Gas and Whiting Programs, Inc. (the "2014 Guarantors"). Additionally, the Company's obligations under the 2018 notes are fully, unconditionally, jointly and severally guaranteed by the Company's 100%-owned subsidiary, Whiting Oil and Gas (collectively with the 2014 Guarantors, the "Guarantors"). Any subsidiaries other than the Guarantors are minor subsidiaries as defined by Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in guarantor subsidiaries.

4. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the 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, 2011 and December 31, 2010 were \$6.4 million and \$6.1 million, respectively, and are included in accrued liabilities and other. Revisions to the liability could 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, 2011 (in thousands):

Beginning asset retirement obligation at January 1, 2011	\$83,083
Additional liability incurred	720
Revisions in estimated cash flows	127
Accretion expense	1,946
Obligations on sold properties	-
Liabilities settled	(1,469)
Ending asset retirement obligation at March 31, 2011	\$84,407

5. 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, 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 and 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 I (the "Trust") derivatives, entered into to hedge forecasted crude oil and natural gas production revenues, as of April 21, 2011.

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Whiting Petroleum Corporation				
Period	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Apr – Dec 2011	8,140,289	322,092	\$61.01 - \$98.31	\$6.32 - \$13.64
Jan – Dec 2012	7,905,091	384,002	\$59.97 - \$106.27	\$6.50 - \$14.27
Jan – Nov 2013	3,090,000	-	\$47.64 - \$89.90	n/a
Total	19,135,380	706,094		

Derivatives Conveyed to Whiting USA Trust I. In connection with the Company's conveyance in April 2008 of a term net profits interest to the Trust and related sale of 11,677,500 Trust 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 the Trust, and therefore such payments will be included in the Trust's calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties. Whiting's retention of 10% of these net proceeds, combined with its ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, and Whiting retaining 24.2%, of the future economic results of commodity derivative contracts conveyed to the Trust. 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 assets.

The 24.2% portion of Trust derivatives that Whiting has retained the economic rights to (and which are also included in the table above) are as follows:

Whiting Petroleum Corporation				
Period	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Apr – Dec 2011	85,289	322,092	\$74.00 - \$140.32	\$6.32 - \$13.64
Jan – Dec 2012	105,091	384,002	\$74.00 - \$141.72	\$6.50 - \$14.27
Total	190,380	706,094		

The 75.8% portion of Trust derivative contracts of which Whiting has transferred the economic rights to third-party public holders of Trust units (and which have not been reflected in the above tables) are as follows:

Third-party Public Holders of Trust Units				
Period	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Apr – Dec 2011	267,145	1,008,867	\$74.00 - \$140.32	\$6.32 - \$13.64
Jan – Dec 2012	329,171	1,202,785		

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			\$74.00 -	\$6.50 -
			\$141.72	\$14.27
Total	596,316	2,211,652		

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Discontinuance of Cash Flow Hedge Accounting—Prior to April 1, 2009, the Company designated a portion of its commodity derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to other comprehensive income. Effective April 1, 2009, however, 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 accumulated other comprehensive income as of the de-designation date and are being reclassified into earnings as the original hedged transactions affect income. As of March 31, 2011, accumulated other comprehensive income amounted to \$6.1 million (\$3.8 million net of tax), which consisted entirely of unrealized deferred gains and losses on commodity derivative contracts that had been previously designated as cash flow hedges. During the next twelve months, the Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax gains of \$4.3 million related to de-designated commodity hedges. Currently, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income.

Embedded Commodity Contracts—As of March 31, 2011, Whiting had entered into nine contracts with drilling rig companies, whereby the rig day rates included price adjustment clauses that are linked to changes in NYMEX crude oil prices. These drilling rig contracts have various termination dates ranging from June 2011 to May 2014. The price adjustment formulas in the rig contracts stipulate that with every \$10 increase or decrease in the price of NYMEX crude, the cost of drilling rig day rates to the Company will likewise increase or decrease by specific dollar amounts as set forth in each of the individual contracts. The Company has determined that the portions of drilling rig day rates linked to NYMEX oil prices are not clearly and closely related to the host drilling contracts, and the Company has therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in the consolidated financial statements.

As global crude oil prices increase or decrease, the demand for drilling rigs in North America similarly increases and decreases. Because the supply of onshore drilling rigs in North America is fairly inelastic, these changes in rig demand cause drilling rig day rates to increase or decrease in tandem with crude oil price fluctuations. When the Company enters into a long-term drilling rig contract that has a fixed rig day rate which does not increase or decrease with changes in oil prices, the Company is exposed to the risk of paying higher than the market day rate for drilling rigs in a climate of rapidly declining oil prices. This in turn could have a negative impact on the Company's oil and gas well economics. As a result, the Company reduces its exposure to this risk by entering into drilling contracts which have rig day rates that fluctuate in tandem with changes in oil prices.

Derivative Instrument Reporting—All derivative instruments are recorded on the consolidated balance sheet at fair value, other than derivative instruments that meet the “normal purchase normal sales” exclusion. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets (in thousands).

Not Designated as ASC 815 Hedges	Balance Sheet Classification	Fair Value	
		March 31, 2011	December 31, 2010
Derivative assets:			
Commodity contracts	Prepaid expenses and other	\$ 2,734	\$ 4,231
Commodity contracts	Other long-term assets	1,579	3,961
Total derivative assets		\$ 4,313	\$ 8,192
Derivative liabilities:			
Commodity contracts	Current derivative liabilities	\$ 138,232	\$ 69,375

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Embedded commodity contracts	Current derivative liabilities	2,571	-
Commodity contracts	Non-current derivative liabilities	146,047	95,256
Embedded commodity contracts	Non-current derivative liabilities	510	-
Total derivative liabilities		\$ 287,360	\$ 164,631

The following tables summarize the effects of commodity derivatives instruments on the consolidated statements of income for the three months ended March 31, 2011 and 2010 (in thousands).

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		Gain (Loss) Reclassified from OCI into Income (Effective Portion) Three Months Ended March 31,	
ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	2011	2010
Commodity contracts	Gain on hedging activities	\$ 3,063	\$ 6,733

		(Gain) Loss Recognized in Income Three Months Ended March 31,	
Not Designated as ASC 815 Hedges	Income Statement Classification	2011	2010
Commodity contracts	Commodity derivative (gain) loss, net	\$ 131,357	\$ (14,923)
Embedded commodity contracts	Commodity derivative (gain) loss, net	3,081	-
Total		\$ 134,438	\$ (14,923)

Contingent Features in Derivative Instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's commodity contracts are high credit-quality financial institutions that are lenders under Whiting's credit agreement. Whiting 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 large 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.

6. FAIR VALUE MEASUREMENTS

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

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

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company reflects transfers between the three levels at the end 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, 2011 and December 31, 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

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	Level 1	Level 2	Level 3	Total Fair Value March 31, 2011
Financial Assets				
Commodity derivatives - current	\$-	\$2,734	\$-	\$2,734
Commodity derivatives - non-current	-	1,579	-	1,579
Total financial assets	\$-	\$4,313	\$-	\$4,313
Financial Liabilities				
Commodity derivatives - current	\$-	\$138,232	\$-	\$138,232
Embedded commodity derivatives - current	-	2,571	-	2,571
Commodity derivatives - non-current	-	146,047	-	146,047
Embedded commodity derivatives - non-current	-	510	-	510
Total financial liabilities	\$-	\$287,360	\$-	\$287,360

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2010
Financial Assets				
Commodity derivatives - current	\$-	\$4,231	\$-	\$4,231
Commodity derivatives - non-current	-	3,961	-	3,961
Total financial assets	\$-	\$8,192	\$-	\$8,192
Financial Liabilities				
Commodity derivatives - current	\$-	\$69,375	\$-	\$69,375
Commodity derivatives - non-current	-	95,256	-	95,256
Total financial liabilities	\$-	\$164,631	\$-	\$164,631

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

Commodity Derivatives. Commodity derivative instruments consist primarily of costless collars for crude oil and natural gas. The Company's costless collars are valued using industry-standard models, which are based on a market approach. These models consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of 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 counterparties' valuations to assess the reasonableness of its own valuations.

Embedded Commodity Derivatives. Embedded commodity derivatives relate to long and short-term contracts that Whiting has entered into with drilling rig companies, whereby the rig day rates include price adjustment clauses that are linked to changes in NYMEX crude oil prices. Whiting has determined that the portion of drilling rig day rates linked to NYMEX oil prices are not clearly and closely related to the host drilling contracts, and the Company has

therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in its consolidated financial statements. These embedded commodity derivatives are valued using industry-standard models, which are based on a market approach. These models consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of 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.

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Non-Recurring Fair Value Measurements. The Company applies the provisions of the fair value measurement standard to its non-recurring, non-financial measurements including business combinations, proved oil and gas property impairments and asset retirement obligations. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The following table presents information about the Company's non-financial assets and liabilities measured at fair value on a non-recurring basis as of March 31, 2011, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Net Carrying Value as of March 31, 2011	Fair Value Measurements Using			Pre-tax (Gain) Loss Three Months Ended March 31, 2011
		Level 1	Level 2	Level 3	
Noncontrolling interest	\$ 8,333	\$ -	\$ -	\$ 8,333	\$ -
Asset retirement obligations	720	-	-	720	-
Total non-recurring assets at fair value	\$ 9,053	\$ -	\$ -	\$ 9,053	\$ -

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

Noncontrolling Interest. In connection with the Company's formation of Sustainable Water Resources, LLC in March 2011, the noncontrolling interest was ascribed a fair value of \$8.3 million in accordance with the provisions of the Identifiable Assets and Liabilities, and Any Noncontrolling Interest Subsections of FASB ASC Subtopic 805-20. Given the unobservable nature of the fair value inputs, these valuations are deemed to use Level 3 inputs.

Asset Retirement Obligations. The Company estimates the fair value of asset retirement obligations at the point they are incurred by calculating the present value of estimated future plug and abandonment costs. Such present value calculations use internally developed cash flow models, which are based on an income approach, and include various assumptions such as estimated amounts and timing of abandonment cash flows, the Company's credit-adjusted risk-free rate and future inflation rates. Given the unobservable nature of most of these inputs, the initial measurement of asset retirement obligation liabilities is deemed to use Level 3 inputs.

7. 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 2%-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, 2011 and 2010 amounted to \$8.0 million and \$6.7 million, respectively, charged to

general and administrative expense and \$0.9 million and \$1.0 million, respectively, charged to exploration expense.

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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, 2011, the Company used three-year average historical NYMEX prices of \$80.74 for crude oil and \$5.30 for natural gas to estimate this liability. 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, 2011, 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 \$163.8 million. This amount includes \$18.9 million attributable to proved undeveloped oil and gas properties and \$8.9 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2012. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control. However, the Company has no intention to terminate the Plan.

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

Beginning long-term Production Participation Plan liability	\$81,524
Change in liability for accretion, vesting, change in estimates and new Plan year activity	8,504
Cash payments accrued as compensation expense and reflected as a current payable	(8,947)
Ending long-term Production Participation Plan liability	\$81,081

8. SHAREHOLDERS' EQUITY

Common Stock—In May 2010, Whiting's stockholders approved an amendment to the Company's Amended and Restated Certificate of Incorporation to increase the number of authorized shares of common stock from 75,000,000 shares to 175,000,000 shares.

Stock Split. On January 26, 2011, the Company's Board of Directors approved a two-for-one split of the Company's shares of common stock to be effected in the form of a stock dividend. As a result of the stock split, stockholders of record on February 7, 2011 received one additional share of common stock for each share of common stock held. The additional shares of common stock were distributed on February 22, 2011. Concurrently with the payment of such stock dividend in February 2011, there was a transfer from additional paid-in capital to common stock of \$0.1 million, which amount represents \$0.001 per share (being the par value thereof) for each share of common stock so issued. All common share and per share amounts in these consolidated financial statements and related notes for periods prior to February 2011 have been retroactively adjusted to reflect the stock split. The common stock dividend resulted in the conversion price for Whiting's 6.25% Convertible Perpetual Preferred Stock being adjusted from \$43.4163 to \$21.70815.

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.

Each holder of the preferred stock is 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, when and if such dividend has been declared by Whiting's board of directors. Each share of preferred stock has a liquidation preference of \$100.00 per share plus accumulated and unpaid dividends and is convertible, at a holder's option, into shares of

Whiting's common stock based on an initial conversion price of \$21.70815, subject to adjustment upon the occurrence of certain events. The preferred stock is not redeemable by the Company. At any time on or after June 15, 2013, the Company may cause all outstanding shares of this preferred stock to be converted into shares of common stock if the closing price of our common stock equals or exceeds 120% of the then-prevailing conversion price for at least 20 trading days in a period of 30 consecutive trading days. The holders of preferred stock have no voting rights unless dividends payable on the preferred stock are in arrears for six or more quarterly periods.

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Induced Conversion of 6.25% Convertible Perpetual Preferred Stock. In August 2010, Whiting commenced an offer to exchange up to 3,277,500, or 95%, of its preferred stock for the following consideration per share of preferred stock: 4.6066 shares of its common stock and a cash premium of \$14.50. The exchange offer expired in September 2010 and resulted in the Company accepting 3,277,500 shares of preferred stock in exchange for the issuance of 15,098,020 shares of common stock and a cash premium payment of \$47.5 million. Following the exchange offer, the 3,277,500 shares of preferred stock accepted in the exchange were cancelled, and a total of 172,500 shares of preferred stock remained outstanding.

Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the “Equity Plan”), pursuant to which 2,978,323 shares of the Company’s common stock have been reserved for issuance. 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, 2011, 1,564,641 shares of common stock remained available for grant under the Plan.

For the three months ended March 31, 2011 and 2010, total stock compensation expense recognized for restricted share awards and stock options was \$3.2 million and \$2.2 million, respectively.

Restricted Shares. Restricted stock awards for executive officers, directors and employees generally vest ratably over a 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 2011 and 2010, 201,420 shares and 180,898 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. These 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.

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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:

	2011	2010
Number of simulations	65,000	65,000
Expected volatility	75.8%	75.9%
Risk-free rate	1.00%	1.40%

The grant date fair value of the market-based restricted stock as determined by the Monte Carlo valuation model was \$42.20 per share in January 2011 and \$22.99 per share in January 2010.

The following table shows a summary of the Company's nonvested restricted stock as of March 31, 2011 as well as activity during the three months then ended (share and per share data, not presented in thousands):

	Number of Shares	Weighted Average Grant Date Fair Value
Restricted stock awards nonvested, January 1, 2011	869,370	\$16.27
Granted	292,888	\$47.84
Vested	(415,382)	\$14.65
Forfeited	(3,014)	\$32.11
Restricted stock awards nonvested, March 31, 2011	743,862	\$29.54

As of March 31, 2011, there was \$15.7 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 2.6 years.

Stock Options. In January 2011 and 2010, 80,820 stock options and 55,302 stock options, respectively, were granted under the Equity Plan 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. These 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 Company uses a Black-Scholes option-pricing model to estimate the fair value of stock option awards. Because the Company first granted stock options in 2009, it does not have historical exercise data upon which to estimate the expected term of the options. As such, the Company has elected to estimate the expected term of the stock options granted using the "simplified" method for "plain vanilla" options. The expected volatility at the grant date is based on the historical volatility of Whiting's common stock, and the risk-free interest rate is determined based on the yield on U.S. Treasury strips with maturities similar to those of the expected term of the stock options. The following table summarizes the assumptions used to estimate the grant date fair value of stock options awarded in each respective period:

	2011	2010
Risk-free interest rate	2.47%	2.75%

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Expected volatility	59.3%	58.8%
Expected term	6.0 yrs.	6.0 yrs.
Dividend yield	-	-

The grant date fair value of the stock options awarded, as determined by the Black-Scholes valuation model, was \$34.15 per share in January 2011 and \$19.44 per share in January 2010.

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The following table shows a summary of the Company's stock options outstanding as of March 31, 2011 as well as activity during the three months then ended (share and per share data, not presented in thousands):

	Number of Options	Weighted Average Exercise Price per Share	Aggregate Intrinsic Value	Weighted Average Remaining Contractual Term (in Years)
Options outstanding at January 1, 2011	296,516	\$ 16.78		
Granted	80,820	60.28		
Exercised	-	-	\$ -	
Forfeited or expired	-	-		
Options outstanding at March 31, 2011	377,336	\$ 26.09	\$ 17,869	8.4
Options vested and expected to vest at March 31, 2011	377,336	\$ 26.09	\$ 17,869	8.4
Options exercisable at March 31, 2011	179,243	\$ 14.97	\$ 10,482	8.0

Unrecognized compensation cost as of March 31, 2011 related to unvested stock option awards was \$3.0 million, which is expected to be recognized over a period of 2.6 years.

9. INCOME TAXES

Income tax expense during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income, plus any significant unusual or infrequently occurring items which are recorded in the interim period. The provision for income taxes for the three months ended March 31, 2011 and 2010 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.

10. EARNINGS PER SHARE

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

	Three Months Ended March 31,	
	2011	2010
Basic Earnings Per Share(1)		
Numerator:		
Net income	\$19,414	\$86,611
Preferred stock dividends	(270)	(5,391)

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Net income available to common shareholders, basic	\$ 19,144	\$ 81,220
Denominator:		
Weighted average shares outstanding, basic	117,243	101,822
Diluted Earnings Per Share(1)		
Numerator:		
Net income available to common shareholders, basic	\$ 19,144	\$ 81,220
Preferred stock dividends	-	5,391
Adjusted net income available to common shareholders, diluted	\$ 19,144	\$ 86,611
Denominator:		
Weighted average shares outstanding, basic	117,243	101,822
Restricted stock and stock options	591	592
Convertible perpetual preferred stock	-	15,892
Weighted average shares outstanding, diluted	117,834	118,306
Earnings per common share, basic	\$0.16	\$0.80
Earnings per common share, diluted	\$0.16	\$0.73

(1) All share and per share amounts have been retroactively restated for the three months ended March 31, 2010 to reflect the Company's February 2011 two-for-one stock split described in Note 8 to these consolidated financial statements.

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For the three months ended March 31, 2011, the diluted earnings per share calculation excludes the effect of 794,330 incremental common shares, which were issuable upon the assumed conversion of perpetual preferred stock because their effect was anti-dilutive.

11. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In December 2010, the FASB issued Accounting Standards Update No. 2010-29, Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations (“ASU 2010-29”), which provides amendments to FASB ASC Topic 805, Business Combinations. The objective of ASU 2010-29 is to clarify and expand the pro forma revenue and earnings disclosure requirements for business combinations. ASU 2010-29 is effective for fiscal years beginning after December 15, 2010. The Company adopted ASU 2010-29 effective January 1, 2011, which did not have an impact on the Company’s consolidated financial statements.

12. SUBSEQUENT EVENT

In April 2011, Whiting Oil and Gas entered into an amendment to its credit agreement that decreased the interest margins on outstanding borrowings and extended the principal repayment date to April 2016.

The amended credit agreement provides for interest only payments until April 2016, when the entire amount borrowed is due. 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.

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Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans	Commitment Fee
Less than 0.25 to 1.0	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%

All other terms of the credit agreement remain unchanged.

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

Unless the context otherwise requires, the terms "Whiting," "we," "us," "our" or "ours" when used in this Item refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation, Sustainable Water Resources, LLC 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 acquisition, development, exploitation, production and exploration activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan 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 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;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows;
- seeking property acquisitions that complement our core areas; and
- allocating a portion of our capital budget to leasing and exploring prospect areas.

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation 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 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 factors 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 since the first quarter of 2010:

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	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Q1 2011
Crude Oil	\$78.79	\$77.99	\$76.21	\$85.18	\$94.25
Natural Gas	\$5.30	\$4.09	\$4.39	\$3.81	\$4.10

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 reserve bookings. 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 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 non-cash mark-to-market losses being recognized on our commodity derivatives, which may in turn cause us to experience net losses.

First Quarter 2011 Highlights and Future Considerations

Operational Highlights. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations. Net production in the Sanish field increased 43% from 15.2 MBOE/d in the first quarter of 2010 to 21.7 MBOE/d in the first quarter of 2011. From January 1 through April 15, 2011, we completed 15 operated Bakken wells and seven operated Three Forks wells in the Sanish field, bringing to 158 the total number of operated wells in the field. As of April 15, 2011, 17 operated wells were being completed or awaiting completion and nine operated wells were being drilled in the Sanish field. In 2011, we intend to drill a total of 95 gross (54 net) operated wells in the Sanish field, of which 70 are planned Three Forks wells. We plan to continue with our current nine operated drilling rig count in the Sanish field through 2013.

At our Robinson Lake gas plant in North Dakota, we recently completed Phase II of the expansion plan, which brought the plant's inlet capacity to 60 MMcf/d, and we expect to continue expanding the plant's capacity during the third quarter of 2011. As of April 15, 2011, the plant was processing 34.8 MMcf/d.

Our Lewis & Clark prospect area is located primarily in Stark County, North Dakota and runs 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 Three Forks formation. We hold a working interest in 250 1,280-acre spacing units in Lewis & Clark, and we estimate two to four wells per 1,280-acre spacing unit to fully develop this area. From January 28 to April 18, 2011, we completed eight wells at Lewis & Clark. Due to mechanical difficulties experienced at two of these eight wells, we believe that not all of the wells' total number of frac stages are contributing to the current production from these two wells. The remaining six wells exhibited variations in initial production rates reflecting rock quality and pressure differences which vary across Lewis & Clark. We continue to refine our completion procedures in this area in an effort to improve production rates. We currently have five drilling rigs operating in this prospect, and we plan to increase this rig count to nine by the third quarter of 2011. We recently broke ground on the construction of a gas processing plant at Lewis & Clark, which is expected to be completed by November 2011.

We continue to have significant development and related infrastructure activity in the Postle and North Ward Estes fields acquired in 2005, which have resulted in reserve additions and production increases at both fields. Our expansion of the CO₂ floods at these fields continues to generate positive results.

The North Ward Estes field is located in Ward and Winkler Counties, Texas and is responding positively to our water and CO₂ floods, which we initiated in May 2007. In the first quarter of 2011, production from North Ward Estes averaged 8.1 MBOE/d representing an 8% increase from first quarter 2010 levels. As a result of additional

compression and increased CO₂ injection, production from the field has increased. Whiting is currently injecting approximately 260 MMcf/d of CO₂ into the field, of which about half is recycled. In this field, we plan to install oil, gas and water processing facilities in eight phases. The first two phases were largely completed by December 2009, and Phase III began in December 2010. We plan to have all eight phases implemented by 2016.

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Net production from the Postle field, which is located in Texas County, Oklahoma and produces from the Morrow sandstone, averaged 8.5 MBOE/d in the first quarter of 2011, representing a 5% decrease from the 8.9 MBOE/d rate in the fourth quarter of 2010, which decline was primarily the result of normal CO₂ injection variations. We recently increased CO₂ injection in the Postle field and expect moderate production increases over the next several months.

Acquisition Highlights. On February 15, 2011, we completed the acquisition of 6,000 net undeveloped acres and additional working interests in the Pronghorn field in Billings and Stark Counties, North Dakota, for an aggregate purchase price of \$40.0 million and an effective date of February 1, 2011.

Financing Highlights. On January 26, 2011, our Board of Directors approved a two-for-one split of the Company's shares of common stock to be effected in the form of a stock dividend. As a result of the stock split, stockholders of record on February 7, 2011 received one additional share of common stock for each share of common stock held. The additional shares of common stock were distributed on February 22, 2011. All common share and per share amounts in this Quarterly Report on Form 10-Q for periods prior to February 2011 have been retroactively adjusted to reflect the stock split.

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Results of Operations

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010

Selected Operating Data:	Three Months Ended March 31,	
	2011	2010
Net production:		
Oil (MMBbls)	4.8	4.3
Natural gas (Bcf)	7.0	6.6
Total production (MMBOE)	5.9	5.4
Net sales (in millions):		
Oil (1)	\$390.7	\$303.7
Natural gas (1)	35.0	37.0
Total oil and natural gas sales	\$425.7	\$340.7
Average sales prices:		
Oil (per Bbl)	\$81.84	\$70.72
Effect of oil hedges on average price (per Bbl)	(1.70) (2.04
Oil net of hedging (per Bbl)	\$80.14	\$68.68
Average NYMEX price (per Bbl)	\$94.25	\$78.79
Natural gas (per Mcf)	\$5.00	\$5.63
Effect of natural gas hedges on average price (per Mcf)	0.04	0.04
Natural gas net of hedging (per Mcf)	\$5.04	\$5.67
Average NYMEX price (per Mcf)	\$4.10	\$5.30
Cost and expense (per BOE):		
Lease operating expenses	\$12.04	\$11.30
Production taxes	\$5.33	\$4.66
Depreciation, depletion and amortization expense	\$18.14	\$18.11
General and administrative expenses	\$3.10	\$2.53

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased \$85.0 million to \$425.7 million in the first quarter of 2011 compared to the same period in 2010. Sales are a function of oil and gas volumes sold and average sales prices. Our oil sales volumes increased 11% between periods, while our natural gas sales volumes increased 7%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area and at our Lewis & Clark field. Oil production from the Bakken in the first quarter of 2011 increased 400 MBbl compared to the first quarter of 2010, while Lewis & Clark oil production increased 95 MBbl over the same prior year period. The gas volume increase between periods was primarily the result of gas production increases of 1,220 MMcf at our Flat Rock area. This production increase was partially offset by normal field production decline, which led to production volume decreases of 155 MMcf at our Southwest Wyoming area, 115 MMcf at each of our Western Texas and North Dakota areas and 105 MMcf at our Boies Ranch area compared to the first quarter of 2010. These increases in oil and gas production were partially offset by the negative impact of weather conditions on production volumes. Inclement weather caused well completion delays in North Dakota, and weather issues in the Postle field and North Ward Estes field resulted in temporary oil and gas production down time. Also contributing to the increase in oil sales revenue in

2011 was an increase in average sales price for oil. Our average price for oil before the effects of hedging increased 16% between periods. This increase was partially offset by an 11% decrease in our average price for natural gas before the effects of hedging.

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Gain on Hedging Activities. Our gain on hedging activities decreased \$3.7 million in 2011 as compared to the first quarter of 2010, and it consisted of the following (in thousands):

	Three Months Ended March 31,	
	2011	2010
Gains reclassified from AOCI on de-designated hedges	\$3,063	\$6,733

Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges, and we elected to discontinue all hedge accounting prospectively. Accordingly, each period we reclassify from accumulated other comprehensive income (“AOCI”) into earnings unrealized gains (which were frozen in AOCI on the April 1, 2009 de-designation date) upon the expiration of these de-designated crude oil hedges, and we report such non-cash unrealized gains as gain on hedging activities.

See Item 3, “Qualitative and Quantitative Disclosures About Market Risk” for a list of our outstanding oil and natural gas derivatives as of April 21, 2011.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during the first quarter of 2011 were \$71.5 million, a \$10.7 million increase over the same period in 2010. Our lease operating expenses on a BOE basis also increased from \$11.30 during the first quarter of 2010 to \$12.04 during the first quarter of 2011. This rise in LOE in 2011 was related to a higher level of workover activity, as well as increases of \$0.9 million in transportation charges and \$0.9 million in gathering costs between periods. Workovers increased to \$22.0 million in the first quarter of 2011, as compared to \$12.6 million in the first quarter of 2010, primarily due to a higher number of well workovers being conducted on our two CO2 projects. The increase in transportation charges was primarily due to higher transportation fees on non-operated properties in the Bakken.

Production Taxes. Our production taxes during the first quarter of 2011 were \$31.6 million, a \$6.5 million increase over the same period in 2010, which increase was primarily due to higher oil and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging, and we take advantage of credits and exemptions allowed in our various taxing jurisdictions. As a percentage of oil and gas sales before the effects of hedging, our company-wide production tax rates for the first quarter of 2011 and 2010 remained constant at 7.4%.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization (“DD&A”) expense increased \$10.2 million in 2011 as compared to the first quarter of 2010. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended March 31,	
	2011	2010
Depletion	\$105,211	\$95,324
Depreciation	571	492
Accretion of asset retirement obligations	1,946	1,733
Total	\$107,728	\$97,549

DD&A increased in the first quarter of 2011 primarily due to \$9.9 million in higher depletion expense between periods. This increase was the result of \$9.8 million in higher depletion due to a rise in overall production volumes during the first quarter of 2011 and \$0.1 million in higher depletion due to an increase in our depletion rate between periods. On a BOE basis, our DD&A rate of \$18.14 for the first quarter of 2011 was up from the rate of \$18.11 for

the same period in 2010. The higher DD&A rate was mainly due to \$909.9 million in drilling and development expenditures incurred during the past twelve months, which was partially offset by a net increase in our estimated proved reserves of 29.8 MMBOE as of December 31, 2010.

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Exploration and Impairment Costs. Our exploration and impairment costs increased \$9.3 million in the first quarter of 2011, as compared to the first quarter of 2010. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended March 31,	
	2011	2010
Exploration	\$ 14,599	\$ 9,063
Impairment	7,638	3,843
Total	\$ 22,237	\$ 12,906

Exploration costs increased \$5.5 million during the first quarter of 2011 as compared to the same period in 2010 primarily due to an increase in geological and geophysical (“G&G”) activity and higher exploratory dry hole costs. G&G costs, such as seismic studies, amounted to \$6.6 million during the first quarter of 2011 as compared to \$3.3 million during the same period in 2010. During the three months ended March 31, 2011, we drilled three exploratory dry holes in the Rocky Mountains, Permian Basin and Gulf Coast regions totaling \$2.9 million, while we drilled one exploratory dry hole in the Gulf Coast region totaling \$2.0 million during the first three months of 2010. Impairment expense in the first quarter of 2011 and 2010 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties, and a higher number of insignificant undeveloped leaseholds that were subject to amortization as of March 31, 2011 compared to March 31, 2010.

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,	
	2011	2010
General and administrative expenses	\$ 33,988	\$ 26,952
Reimbursements and allocations	(15,575)	(13,318)
General and administrative expense, net	\$ 18,413	\$ 13,634

General and administrative expenses before reimbursements and allocations increased \$7.0 million during the first quarter of 2011 as compared to the same period in 2010 primarily due to higher employee compensation and an increase in accrued Production Participation Plan (“Plan”) distributions. Employee compensation increased \$5.3 million in the first quarter of 2011 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. Accrued distributions under the Plan increased \$1.3 million between periods. The increase in reimbursements and allocations in the first quarter of 2011 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales remained constant at 4% for the first quarters of 2010 and 2011.

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

	Three Months Ended March 31,	
	2011	2010
Senior Subordinated Notes	\$ 10,062	\$ 11,081
Credit agreement	3,193	2,144
Amortization of debt issue costs and debt discount	2,127	2,516
Other	18	376
Capitalized interest	(942)	(425)
Total	\$ 14,458	\$ 15,692

The decrease in interest expense of \$1.2 million between periods was mainly due to lower interest of \$1.0 million on our Senior Subordinated Notes due to the redemption of \$150.0 million of 7.25% notes due 2012 and \$220.0 million of 7.25% notes due 2013 in early September 2010. Also in September 2010, we subsequently issued \$350.0 million of 6.5% notes due 2018. In addition, we incurred higher amounts of capitalized interest between periods due to an increase in costs capitalized on projects requiring longer than six months to be substantially complete and ready for use. These decreases in interest were partially offset by higher borrowings outstanding under our credit agreement during the first quarter of 2011, which increased the interest on our credit agreement by \$1.0 million. Our weighted average debt outstanding during the first quarter of 2011 was \$931.2 million versus \$771.2 million for the first quarter of 2010. Our weighted average effective cash interest rate was 5.7% during the first quarter of 2011 compared to 6.9% during the first quarter of 2010.

Commodity Derivative (Gain) 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. Cash flow is only impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded immediately to earnings as commodity derivative (gain) loss, net. The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Three Months Ended March 31,	
	2011	2010
Change in unrealized (gains) losses on derivative contracts	\$ 126,607	\$ (23,487)
Realized cash settlement losses	7,831	8,564
Total	\$ 134,438	\$ (14,923)

With respect to our open derivative contracts at March 31, 2011 and 2010, the futures curve of forecasted commodity prices ("forward price curve") for crude oil generally exceeded the forward price curves that were in effect when these contracts were entered into, resulting in a net fair value liability position at the end of each respective period. The change in unrealized (gains) losses on derivative contracts in the first quarter of 2011 resulted in a \$126.6 million loss in such net liability position due to the significant upward shift in the forward price curve for NYMEX crude oil from January 1 to March 31, 2011. The change in unrealized (gains) losses on derivative contracts in the first quarter of 2010, on the other hand, resulted in a \$23.5 million gain due to the downward shift in the same forward price curve from January 1 to March 31, 2010.

Income Tax Expense. Income tax expense totaled \$12.8 million for the first quarter of 2011, as compared to \$52.9 million of income tax for the first quarter of 2010. However, our effective income tax rate increased to 39.8% for the first quarter of 2011 as compared to a rate of 37.9% for the same period in 2010. This change in our effective income

tax rate was primarily due to current state income tax expense in certain states staying relatively constant, while pre-tax book income decreased significantly between periods.

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Our effective tax rates for the periods ended March 31, 2011 and 2010 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences.

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Liquidity and Capital Resources

Overview. At March 31, 2011, our debt to total capitalization ratio was 27.8%, we had \$5.0 million in cash on hand and \$2,551.1 million of equity. At December 31, 2010, our debt to total capitalization ratio was 24.0%, we had \$19.0 million of cash on hand and \$2,531.3 million of equity. In the first quarter of 2011, we generated \$214.1 million of cash provided by operating activities, an increase of \$17.5 million over the same period in 2010. Cash provided by operating activities increased primarily due to higher crude oil and natural gas production volumes and higher average sales price for crude oil. These positive factors were partially offset by lower average sales price for natural gas in the first quarter of 2011, as well as increased lease operating expenses, production taxes, G&G costs and general and administrative expenses during the first quarter of 2011 as compared to the same period in 2010. Cash flows from operating activities and net borrowings under our credit agreement totaling \$180.0 million were used to finance \$284.8 million of drilling and development expenditures, \$91.5 million of cash acquisition capital expenditures paid in the first quarter of 2011 and the issuance of a \$25.0 million note receivable. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region during the first quarter of 2011 (in thousands):

	Drilling and Development Expenditures (1)	Undeveloped Leasehold Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	\$ 200,558	\$ 70,609	\$ 9,274	\$ 280,441	72%
Permian Basin	57,082	11,044	3,796	71,922	18%
Mid-Continent	28,733	-	600	29,333	8%
Gulf Coast	3,806	(23)	897	4,680	1%
Michigan	4,156	22	32	4,210	1%
Total incurred	294,335	81,652	14,599	390,586	100%
Increase in accrued capital expenditures	(12,485)	-	-	(12,485)	
Total paid	\$ 281,850	\$ 81,652	\$ 14,599	\$ 378,101	

(1) For purposes of this schedule, exploratory dry hole costs of \$2.9 million are excluded from drilling and development expenditures as reported on the statement of cash flows and instead have been included in exploration expenditures above.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2011 capital budget is \$1,350.0 million. This represents a 38% increase from the \$978.3 million incurred on exploration, development and acreage expenditures during 2010. We expect to fund substantially all of our 2011 capital budget with net cash provided by our operating activities. We have increased our 2011 capital budget from our actual level of 2010 expenditures in response to higher oil prices experienced throughout 2010 and continuing into the first part of 2011, as well as in response to higher crude oil production volumes. Although we have only budgeted \$110.0 million for property acquisitions in 2011, 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 \$1,350.0 million, 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, or agreements with industry partners. 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.

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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, 2011 had a borrowing base of \$1.1 billion with \$718.5 million of available borrowing capacity, which was net of \$380.0 million in borrowings and \$1.5 million in letters of credit outstanding. In April 2011, Whiting Oil and Gas entered into an amendment to its credit agreement that decreased the interest margins on outstanding borrowings and extended the principal repayment date to April 2016.

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 the 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, 2011, \$48.5 million was available for additional letters of credit under the agreement.

The amended credit agreement provides for interest only payments until April 2016, when the entire amount borrowed is 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, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, the credit agreement also restricts our ability to make any dividend payments or distributions on our common stock. These restrictions apply to all of the net assets of the subsidiaries. The credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters’ EBITDAX ratio (as defined in the credit agreement) of 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for quarters ending March 31, 2013 and thereafter 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 its covenants under the credit agreement as of March 31, 2011.

For further information on the interest rates and loan security related to our existing credit agreement at March 31, 2011, refer to the Long-Term Debt footnote in the Notes to Consolidated Financial Statements.

Senior Subordinated Notes. In September 2010, we issued at par \$350.0 million of 6.5% Senior Subordinated Notes due October 2018. In October 2005, we issued at par \$250.0 million of 7% Senior Subordinated Notes due February 2014.

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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, 2011. However, a substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liability of \$90.0 million (which amount comprises both the long and short-term portions of this obligation) as of March 31, 2011, since we cannot determine with accuracy the timing or amounts of future payments. The following table summarizes our obligations and commitments as of March 31, 2011 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

Contractual Obligations	Total	Payments due by period			
		Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (a)	\$ 980,000	\$ -	\$ 250,000	\$ 380,000	\$ 350,000
Cash interest expense on debt (b)	264,642	50,032	97,147	60,588	56,875
Derivative contract liability fair value (c)	287,360	140,803	146,557	-	-
Asset retirement obligation (d)	84,407	6,440	6,454	6,465	65,048
Tax sharing liability (e)	23,003	1,786	3,187	18,030	-
Purchasing obligations (f)	241,681	53,048	125,959	62,674	-
Drilling rig contracts (g)	162,011	60,515	92,370	9,126	-
Operating leases (h)	8,418	3,574	4,844	-	-
Total	\$ 2,051,522	\$ 316,198	\$ 726,518	\$ 536,883	\$ 471,923

(a) Long-term debt consists of the 7% Senior Subordinated Notes due 2014, the 6.5% Senior Subordinated Notes due 2018 and the outstanding borrowings under our credit agreement, and assumes no principal repayment until the due date of the instruments.

(b) Cash interest expense on the 7% Senior Subordinated Notes due 2014 and the 6.5% Senior Subordinated Notes due 2018 is estimated assuming no principal repayment until the due date of the instruments. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the instrument due date and is estimated at a fixed interest rate of 2.6%.

- (c) The above derivative obligation at March 31, 2011 consists of a \$281.0 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. With respect to our open derivative contracts at March 31, 2011 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. The above derivative obligation at March 31, 2011 also consists of a \$3.3 million payable to Whiting USA Trust I (the "Trust") for derivative contracts that we have entered into but have in turn conveyed to the Trust. Although these derivatives are in a fair value asset position at quarter end, 75.8% of such derivative assets are due to the Trust under the terms of the conveyance. The remaining \$3.1 million derivative fair value liability relates to embedded commodity-based derivatives.
- (d) 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 facilities.
- (e) Amounts shown represent the present value of estimated payments due to Alliant Energy based on projected future income tax benefits attributable to an increase in our tax bases. As a result of the Tax Separation and Indemnification Agreement signed with Alliant Energy, the increased tax bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay Alliant Energy 90% of the future tax benefits we realize annually as a result of this step up in tax basis for the years ending on or prior to December 31, 2013. In 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years.
- (f) We have three take-or-pay purchase agreements, all expiring in December 2014, whereby we have committed to buy certain volumes of CO₂ for use in enhanced recovery projects in our Postle field in Oklahoma and our North Ward Estes field 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 a ship-or-pay agreement expiring in June 2013, whereby we have committed to transport a minimum daily volume of CO₂ via the Transpetco pipeline or else pay for any deficiencies at a price stipulated in the contract. The CO₂ volumes planned for use in the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes specified in 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.

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- (g) We currently have nine drilling rigs under long-term contract, of which one drilling rig expires in 2011, three in 2012, two in 2013 and three in 2014. All of these rigs are operating in the Rocky Mountains region. As of March 31, 2011, early termination of the remaining contracts would require termination penalties of \$103.3 million, which would be in lieu of paying the remaining drilling commitments of \$162.0 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.
- (h) We lease 116,100 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, and an additional 46,700 square feet of office space in Midland, Texas expiring in 2012.

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, 2010.

Effects of Inflation and Pricing

During the first quarter of 2010, we began to experience moderate cost increases, as the demand for oil field products and services had begun to rise from 2009 levels. These price increases continued through the remainder of 2010 and in the first quarter of 2011. 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 put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Forward-Looking Statements

This report contains statements that we believe to be “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. 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 “show” or the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

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These risks and uncertainties include, but are not limited to: declines in oil or natural gas prices; impacts of the global recession and tight credit markets; our level of success in exploitation, exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures, including our ability to obtain CO₂; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; 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; 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; 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 fiscal year ended December 31, 2010. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2010 and have not materially changed since that report was filed.

Our outstanding hedges as of April 21, 2011 are summarized below:

Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	04/2011 to 06/2011	895,000	\$60.87 / \$97.87
Crude Oil	07/2011 to 09/2011	895,000	\$60.87 / \$97.87
Crude Oil	10/2011 to 12/2011	895,000	\$60.87 / \$97.87
Crude Oil	01/2012 to 03/2012	650,000	\$59.74 / \$105.79
Crude Oil	04/2012 to 06/2012	650,000	\$59.74 / \$105.79
Crude Oil	07/2012 to 09/2012	650,000	\$59.74 / \$105.79
Crude Oil	10/2012 to 12/2012	650,000	\$59.74 / \$105.79
Crude Oil	01/2013 to 03/2013	290,000	\$47.67 / \$90.21
Crude Oil	04/2013 to 06/2013	290,000	\$47.67 / \$90.21
Crude Oil	07/2013 to 09/2013	290,000	\$47.67 / \$90.21
Crude Oil	10/2013	290,000	\$47.67 / \$90.21
Crude Oil	11/2013	190,000	\$47.22 / \$85.06

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I (the "Trust"), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 787 MBbls of crude oil and 2,918 MMcf of natural gas from 2011 through 2012, have been conveyed to the Trust, and therefore such payments will be included in the Trust's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. Our retention of 10% of these net proceeds combined with our ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, while we retain 24.2%, of future economic results of such hedges. No additional hedges are allowed to be placed on Trust assets.

The table below summarizes all of the costless collars that we entered into and then in turn conveyed, as described in the preceding paragraph, to Whiting USA Trust I (of which we retain 24.2% of the future economic results and third-party public holders of Trust units receive 75.8% of the future economic results):

Conveyed to Whiting USA Trust I

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	04/2011 to 06/2011	40,066	\$74.00 / \$140.08
Crude Oil	07/2011 to 09/2011	39,170	\$74.00 / \$140.15
Crude Oil	10/2011 to 12/2011	38,242	\$74.00 / \$140.75
Crude Oil	01/2012 to 03/2012	37,412	\$74.00 / \$141.27
Crude Oil	04/2012 to 06/2012	36,572	\$74.00 / \$141.73
Crude Oil	07/2012 to 09/2012	35,742	\$74.00 / \$141.70

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Crude Oil	10/2012 to 12/2012	35,028	\$74.00 / \$142.21
Natural Gas	04/2011 to 06/2011	152,703	\$6.00 / \$13.05
Natural Gas	07/2011 to 09/2011	148,163	\$6.00 / \$13.65
Natural Gas	10/2011 to 12/2011	142,787	\$7.00 / \$14.25
Natural Gas	01/2012 to 03/2012	137,940	\$7.00 / \$15.55
Natural Gas	04/2012 to 06/2012	134,203	\$6.00 / \$13.60
Natural Gas	07/2012 to 09/2012	130,173	\$6.00 / \$14.45
Natural Gas	10/2012 to 12/2012	126,613	\$7.00 / \$13.40

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The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the crude oil contracts listed in both tables above, a hypothetical \$10.00 per Bbl change in the NYMEX forward curve as of March 31, 2011 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of \$142.9 million. For the natural gas contracts listed above, a hypothetical \$1.00 per Mcf change in the NYMEX forward curve as of March 31, 2011 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of \$0.5 million.

We have various fixed price gas sales contracts with end users for a portion of the natural gas we produce in Colorado, Michigan and Utah. Our estimated future production volumes to be sold under these fixed price contracts as of April 21, 2011 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	04/2011 to 06/2011	778,914	\$5.31
Natural Gas	07/2011 to 09/2011	772,460	\$5.30
Natural Gas	10/2011 to 12/2011	772,460	\$5.30
Natural Gas	01/2012 to 03/2012	577,127	\$5.30
Natural Gas	04/2012 to 06/2012	461,460	\$5.41
Natural Gas	07/2012 to 09/2012	465,794	\$5.41
Natural Gas	10/2012 to 12/2012	398,667	\$5.46
Natural Gas	01/2013 to 03/2013	360,000	\$5.47
Natural Gas	04/2013 to 06/2013	364,000	\$5.47
Natural Gas	07/2013 to 09/2013	368,000	\$5.47
Natural Gas	10/2013 to 12/2013	368,000	\$5.47
Natural Gas	01/2014 to 03/2014	330,000	\$5.49
Natural Gas	04/2014 to 06/2014	333,667	\$5.49
Natural Gas	07/2014 to 09/2014	337,333	\$5.49
Natural Gas	10/2014 to 12/2014	337,333	\$5.49

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our management evaluated, with the participation of our Chairman 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, 2011. 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, 2011 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended March 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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

In November 2010, Whiting previously disclosed a well incident at the Roggenbuck 14-25H well in North Dakota in which a valve near the wellhead failed resulting in water, oil and natural gas flowing from the well, with Whiting containing and hauling from the well site the liquids being produced. Whiting received a complaint, dated February 15, 2011, in an administrative action by the North Dakota Industrial Commission (the “NDIC”) alleging that in connection with such incident Whiting violated certain sections of the North Dakota Administrative Code governing the oil and gas industry, including by not controlling subsurface pressure on a well, by allowing oil and brine to flow over and pool on the surface of the land and by not properly maintaining a dike on the well site. The complaint requests that Whiting pay aggregate fines of \$162,500 and costs and expenses of \$4,357. The incident described above was of relatively short duration, was fully and promptly remediated and there were no injuries. Whiting is currently negotiating a resolution of the complaint with the NDIC and expects to complete the process in May 2011.

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, 2010. No material change to such risk factors has occurred during the three months ended March 31, 2011.

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

On February 1, 2011, Whiting issued 460 shares of its common stock upon conversion of 100 shares of its 6.25% convertible perpetual preferred stock (the “Preferred Stock”). Pursuant to its terms, each share of Preferred Stock is convertible, at the holder’s option at any time, into shares of Whiting’s common stock based on a conversion price that is \$21.70815, subject to adjustment (the “Conversion Price”). The issuance of such shares qualified for the exemption provided by Section 3(a)(9) of the Securities Act of 1933, as amended. Whiting received no additional consideration for the issuance of its shares of common stock. The common share amount and the Conversion Price included herein have been retroactively adjusted to reflect the two-for-one split of Whiting’s shares of common stock effected on February 22, 2011.

Item 6. Exhibits

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

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on this 29th day of April, 2011.

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

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(4.1)	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 15, 2011, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, the various other agents party thereto and the lenders party thereto.
(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, 2011 are furnished herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of March 31, 2011 and December 31, 2010, (ii) the Consolidated Statements of Income for the Three Months Ended March 31, 2011 and 2010, (iii) the Consolidated Statements of Cash Flow for the Three Months Ended March 31, 2011 and 2010, (iv) the Consolidated Statements of Equity and Comprehensive Income for the Three Months Ended March 31, 2011 and 2010, and (v) Notes to Consolidated Financial Statements.