WHITING PETROLEUM CORP
Form 10-Q
April 30, 2009

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2009
or

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

For the transition period from _______________ to _______________

Commission file number: 001-31899

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

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

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

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

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

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

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

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

Number of shares of the registrant's common stock outstanding at April 15, 2009: 50,841,400 shares.

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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.

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

“MBOE” - One thousand BOE.

“MBOE/d” - One thousand BOE per day.

“Mcf” - One thousand cubic feet of natural gas.

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

“MMBOE” - One million BOE.

“MMBtu” - One million British Thermal Units.

“MMcf” - One million cubic feet of natural gas.

“MMcf/d” - One MMcf of natural gas per day.

“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; to share in production, subject to all royalties, overriding royalties and other burdens; and to share in all costs of exploration, development, 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)

	March 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 7,013	$ 9,624
Accounts receivable trade, net	94,225	123,386
Derivative assets	44,647	46,780
Deposits on oil field equipment	11,317	17,170
Prepaid expenses and other	17,035	20,114
Total current assets	174,237	217,074
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	4,604,617	4,423,197
Unproved properties	104,109	106,436
Other property and equipment	106,813	91,099
Total property and equipment	4,815,539	4,620,732
Less accumulated depreciation, depletion and amortization	(984,652)	(886,065)
Total property and equipment, net	3,830,887	3,734,667
DEBT ISSUANCE COSTS	9,741	10,779
DERIVATIVE ASSETS	39,214	38,104
OTHER LONG-TERM ASSETS	26,116	28,457
TOTAL	$ 4,080,195	$ 4,029,081

See notes to consolidated financial statements. (Continued)

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

	March 31, 2009	December 31, 2008
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 46,752	$ 64,610
Accrued capital expenditures	47,592	84,960
Accrued liabilities	47,107	45,359
Accrued interest	19,919	9,673
Oil and gas sales payable	23,045	35,106
Accrued employee compensation and benefits	4,958	41,911
Production taxes payable	14,487	20,038
Deferred gain on sale	14,017	14,650
Derivative liabilities	13,456	17,354
Deferred income taxes	15,835	15,395
Tax sharing liability	2,112	2,112
Total current liabilities	249,280	351,168
NON-CURRENT LIABILITIES:		
Long-term debt	1,189,556	1,239,751
Deferred income taxes	376,625	390,902
Deferred gain on sale	69,834	73,216
Production Participation Plan liability	66,562	66,166
Asset retirement obligations	59,838	47,892
Tax sharing liability	21,984	21,575
Derivative liabilities	23,884	28,131
Other long-term liabilities	3,411	1,489
Total non-current liabilities	1,811,694	1,869,122
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $0.001 par value; 75,000,000 shares authorized, 51,352,981 and 42,582,100 shares issued as of March 31, 2009 and December 31, 2008, respectively	51	43
Additional paid-in capital	1,206,227	971,310
Accumulated other comprehensive income	36,535	17,271
Retained earnings	776,408	820,167
Total stockholders' equity	2,019,221	1,808,791
TOTAL	$ 4,080,195	$ 4,029,081

See notes to consolidated financial statements. (Concluded)

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
REVENUES AND OTHER INCOME:		
Oil and natural gas sales	$ 146,175	$ 286,731
Gain (loss) on oil and natural gas hedging activities	13,450	(22,912)
Amortization of deferred gain on sale	4,099	-
Interest income and other	115	231
Total revenues and other income	163,839	264,050
COSTS AND EXPENSES:		
Lease operating	60,954	55,706
Production taxes	9,519	17,686
Depreciation, depletion and amortization	100,034	50,511
Exploration and impairment	17,314	10,984
General and administrative	8,980	11,615
Interest expense	14,680	15,546
Change in Production Participation Plan liability	396	6,157
(Gain) loss on mark-to-market derivatives	21,765	(2,937)
Total costs and expenses	233,642	165,268
INCOME (LOSS) BEFORE INCOME TAXES	(69,803)	98,782
INCOME TAX EXPENSE (BENEFIT):		
Current	(539)	1,709
Deferred	(25,505)	34,759
Total income tax expense (benefit)	(26,044)	36,468
NET INCOME (LOSS)	$ (43,759)	$ 62,314
NET INCOME (LOSS) PER COMMON SHARE, BASIC AND DILUTED	$ (0.92)	$ 1.47
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	47,600	42,272
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	47,600	42,406

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, 2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (43,759)	$ 62,314
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	100,034	50,511
Deferred income tax (benefit) expense	(25,505)	34,759
Amortization of debt issuance costs and debt discount	1,173	1,217
Accretion of tax sharing liability	409	311
Stock-based compensation	1,142	1,432
Amortization of deferred gain on sale	(4,099)	-
Unproved leasehold and oil and gas property impairments	4,681	2,572
Change in Production Participation Plan liability	396	6,157
Unrealized (gain) loss on mark-to-market derivatives	23,295	(2,937)
Other non-current	1,496	(3,316)
Changes in current assets and liabilities:		
Accounts receivable trade	30,521	(28,687)
Prepaid expenses and other	8,932	(10,287)
Accounts payable and accrued liabilities	(19,507)	8,771
Accrued interest	10,246	8,857
Other current liabilities	(55,208)	(9,221)
Net cash provided by operating activities	34,247	122,453
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(20,733)	(9,747)
Drilling and development capital expenditures	(201,151)	(160,988)
Proceeds from sale of oil and gas properties	-	234
Other	84	-
Net cash used in investing activities	(221,800)	(170,501)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock	234,942	-
Long-term borrowings under credit agreement	150,000	130,000
Repayments of long-term borrowings under credit agreement	(200,000)	(90,000)
Net cash provided by financing activities	184,942	40,000
NET CHANGE IN CASH AND CASH EQUIVALENTS	(2,611)	(8,048)
CASH AND CASH EQUIVALENTS:		
Beginning of period	9,624	14,778
End of period	$ 7,013	$ 6,730
SUPPLEMENTAL CASH FLOW DISCLOSURES:		
Cash paid (refunded) for income taxes	$ 94	$ (3)
Cash paid for interest	$ 2,852	$ 5,161

NONCASH INVESTING ACTIVITIES:		
Accrued capital expenditures during the period	$ 47,592	$ 74,556

See notes to consolidated financial statements.

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

	Common Stock						
	Shares	Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity	Comprehensive Income (Loss)
BALANCES-January 1, 2008	42,480	$ 42	$ 968,876	$ (46,116)	$ 568,024	$ 1,490,826	
Net income	-	-	-	-	252,143	252,143	$ 252,143
Change in derivative fair values, net of taxes of $1,812	-	-	-	(3,072)	-	(3,072)	(3,072)
Realized loss on settled derivative contracts, net of taxes of $39,903	-	-	-	67,652	-	67,652	67,652
Ineffectiveness gain on hedging activities, net of taxes of $703	-	-	-	(1,193)	-	(1,193)	(1,193)
Restricted stock issued	139	1	-	-	-	1	-
Restricted stock forfeited	(7)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(30)	-	(1,743)	-	-	(1,743)	-
Stock-based compensation	-	-	4,177	-	-	4,177	-
BALANCES-December 31, 2008	42,582	43	971,310	17,271	820,167	1,808,791	$ 315,530
Net loss	-	-	-	-	(43,759)	(43,759)	(43,759)
Change in derivative fair values, net of taxes of $7,706	-	-	-	13,302	-	13,302	13,302
Realized gain on settled derivative contracts, net of taxes of $4,933	-	-	-	(8,517)	-	(8,517)	(8,517)
Ineffectiveness loss on hedging activities, net of taxes of $8,387	-	-	-	14,479	-	14,479	14,479
Issuance of stock, secondary offering	8,450	8	234,934	-	-	234,942	-
Restricted stock issued	351	-	-	-	-	-	-
Restricted stock forfeited	(3)	-	-	-	-	-	-
Restricted stock used for tax withholdings	(27)	-	(644)	-	-	(644)	-

Tax effect from restricted stock vesting	-	-	(515)	-	-	(515)	-
Stock-based compensation	-	-	1,142	-	-	1,142	-
BALANCES-March 31, 2009	51,353	$ 51	$ 1,206,227	$ 36,535	$ 776,408	$ 2,019,221	$ (24,495)
BALANCE-March 31, 2008							$ 63,337

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, all of which are wholly owned, 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 U.S. generally accepted accounting principles 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. Whiting’s 2008 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 has been no material change to the information disclosed in the notes to the consolidated financial statements included in Whiting’s 2008 Annual Report on Form 10-K. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

Earnings Per Share—Basic net income per common share is calculated by dividing net income by the weighted average number of common shares outstanding during each year. Diluted net income per common share is calculated by dividing adjusted net income 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 in-the-money outstanding options to purchase the Company’s common stock. All potentially dilutive securities are anti-dilutive when a loss from continuing operations exists and are excluded from the computation of diluted earnings per share accordingly.

2. ACQUISITIONS AND DIVESTITURES

2009 Activity

There were no significant acquisitions or divestitures during the first quarter of 2009.

2008 Acquisition

Flat Rock Natural Gas Field—On May 30, 2008, Whiting acquired interests in 31 producing gas wells, development acreage and gas gathering and processing facilities on 22,000 gross (11,500 net) acres in the Flat Rock field in Uintah County, Utah for an aggregate acquisition price of $365.0 million.

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This acquisition was recorded using the purchase method of accounting. The table below summarizes the allocation of the $359.4 adjusted purchase price, based on the acquisition date fair value of the assets acquired and the liabilities assumed (in thousands).

	Flat Rock
Purchase price	$ 359,380
Allocation of purchase price:	
Proved properties	$ 251,895
Unproved properties	79,498
Gas gathering and processing facilities	35,736
Liabilities assumed	(7,749)
Total	$ 359,380

Acquisition Pro Forma—In the Company's consolidated statements of income for the year ended December 31, 2008, Flat Rock's results of operations are included with the Company's results beginning May 31, 2008. The following table, however, reflects the unaudited pro forma results of operations for the three months ended March 31, 2008, as though the Flat Rock acquisition had occurred on the first day of the period. The pro forma information below includes numerous assumptions and is not necessarily indicative of what historical results would have been or what future results of operations will be.

	Whiting (As reported)	Pro Forma	
		Flat Rock	Consolidated
Three months ended March 31, 2008:			
Total revenues	$ 264,050	$ 9,882	$ 273,932
Net income	62,314	294	62,608
Net income per common share – basic and diluted	$ 1.47	$ 0.01	$ 1.48

2008 Divestiture

Whiting USA Trust I—On April 30, 2008, the Company completed an initial public offering of units of beneficial interest in Whiting USA Trust I (the "Trust"), selling 11,677,500 Trust units at $20.00 per Trust unit, providing net proceeds of $193.8 million after underwriters' fees, offering expenses, and post-close adjustments. The Company used the net offering proceeds to reduce a portion of the debt outstanding under its credit agreement. The net proceeds from the sale of Trust units to the public resulted in a deferred gain on sale of $100.1 million. Immediately prior to the closing of the offering, Whiting conveyed a term net profits interest in certain of its oil and gas properties to the Trust in exchange for 13,863,889 Trust units. The Company has retained 15.8%, or 2,186,389 Trust units, of the total Trust units issued and outstanding.

The net profits interest entitles the Trust to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate at the time when 9.11 MMBOE have been produced and sold from the underlying properties. This is the equivalent of 8.2 MMBOE in respect of the Trust's right to receive 90% of the net proceeds from such production pursuant to the net profits interest, and these reserve quantities are projected to be produced by December 31, 2021, based on the reserve report for the underlying properties as of December 31, 2008.

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3. LONG-TERM DEBT

Long-term debt consisted of the following at March 31, 2009 and December 31, 2008 (in thousands):

	March 31, 2009	December 31, 2008
Credit Agreement	$ 570,000	$ 620,000
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,440 and $1,541, respectively	218,560	218,459
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $364 and $397, respectively	150,996	151,292
Total debt	$ 1,189,556	$ 1,239,751

Credit Agreement—As of March 31, 2009, the Company's wholly-owned subsidiary, Whiting Oil and Gas Corporation ("Whiting Oil and Gas") had a $1.2 billion credit agreement with a syndicate of banks that had a borrowing base of $900.0 million with $327.2 million of available borrowing capacity, which is net of $570.0 million in borrowings and $2.8 million in letters of credit outstanding. The credit agreement provides for interest only payments until August 2010, when the entire amount borrowed is due. In April 2009, Whiting Oil and Gas entered into a Fourth Amended and Restated Credit Agreement with its bank syndicate, which replaced the existing credit facility. This amended credit agreement increased the Company's borrowing base under the facility to $1.1 billion and extended the principal repayment date to April 2012. Further information on the terms of the new credit agreement is discussed in the note on Subsequent Events.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the 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. Whiting Oil and Gas may, throughout the term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect at any given time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company in an aggregate amount not to exceed $50.0 million. As of March 31, 2009, $47.2 million was available for additional letters of credit under the agreement.

Interest accrues, at Whiting Oil and Gas' option, at either (i) the base rate plus a margin, where the base rate is defined as the higher of the prime rate or the federal funds rate plus 0.5% and the margin varies from 0% to 0.5% depending on the utilization percentage of the borrowing base, or (ii) at the LIBOR rate plus a margin, where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. Commitment fees of 0.25% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage, and are included as a component of interest expense. At March 31, 2009, the weighted average interest rate on the outstanding principal balance under the credit agreement was 1.8%.

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The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material agreements, incur liens and engage in certain other transactions without the prior consent of the lenders. The credit agreement requires the Company to maintain a debt to EBITDAX ratio (as defined in the agreement) of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit facility) of greater than 1 to 1. Except for limited exceptions, including the payment of interest on the senior notes, the credit agreement restricts the ability of Whiting Oil and Gas and Whiting Petroleum Corporation's wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions, principal payments on senior notes, or other payments to Whiting Petroleum Corporation. The restrictions apply to all of the net assets of these subsidiaries. The Company was in compliance with its covenants under the credit agreement as of March 31, 2009. The credit agreement is secured by a first lien on all of Whiting Oil and Gas' properties included in the borrowing base for the agreement. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for its guarantee, and Equity Oil Company has mortgaged all of its properties, that are included in the borrowing base for the credit agreement, 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 2014. The estimated fair value of these notes was $187.5 million as of March 31, 2009, based on quoted market prices for these same debt securities.

In April 2005, the Company issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount of $3.3 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.4%. The estimated fair value of these notes was $174.9 million as of March 31, 2009, based on quoted market prices for these same debt securities.

In May 2004, the Company issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount of $1.1 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.3%. The estimated fair value of these notes was $123.0 million as of March 31, 2009, based on quoted market prices for these same debt securities.

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 indentures governing the notes restrict the Company from incurring additional indebtedness, subject to certain exceptions, unless its fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If the Company were in violation of this covenant, then it 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 various restrictive covenants that are substantially identical and may limit the Company's ability to, among other things, pay cash dividends, redeem or repurchase the Company's capital stock or the Company's subordinated debt, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of the Company's management in certain respects. The Company was in compliance with these covenants as of March 31, 2009. The Company's obligations under the notes are fully, unconditionally, jointly and severally guaranteed by all of the Company's wholly-owned operating subsidiaries, Whiting Oil and Gas, Whiting Programs, Inc. and Equity Oil Company (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.

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Interest Rate Swap—In August 2004, the Company entered into an interest rate swap contract to hedge the fair value of $75.0 million of its 7.25% Senior Subordinated Notes due 2012. The interest rate swap is a fixed for floating swap in that the Company receives the fixed rate of 7.25% and pays the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus the Company's margin of 2.345% is less than 7.25%, the Company receives a payment from the counterparty equal to the difference in rate times $75.0 million for the six month period. When LIBOR plus the Company's margin of 2.345% is greater than 7.25%, the Company pays the counterparty an amount equal to the difference in rate times $75.0 million for the six month period.

The Company designated this swap contract as a fair value hedge, and because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

In March 2009, the counterparty exercised its option to cancel the swap contract effective May 1, 2009, resulting in a cancellation fee of $1.4 million due to the Company. Accordingly, the Company has recorded a current asset of $1.4 million related to the interest rate swap as of March 31, 2009, with an offsetting increase to the fair value of the 7.25% Senior Subordinated Notes due 2012.

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 determines asset retirement obligations by calculating the present value of estimated cash flows related to plug and abandonment obligations. The current portions at March 31, 2009 and December 31, 2008 were $9.9 million and $6.5 million, respectively, and were recorded in accrued liabilities. The following table provides a reconciliation of the Company's asset retirement obligations for the three months ended March 31, 2009 (in thousands):

Asset retirement obligation, January 1, 2009	$	54,348
Additional liability incurred		99
Revisions in estimated cash flows		14,121
Accretion expense		2,198
Liabilities settled		(1,075)
Asset retirement obligation, March 31, 2009	$	69,691

5. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

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 also used to ensure adequate cash flow to fund our capital programs and manage price risks and 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.

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Whiting derivatives—The table below details the Company's costless collar derivatives, including its proportionate share of Trust hedges, entered into to hedge forecasted crude oil and natural gas production revenues, as of April 1, 2009.

	Whiting Petroleum Corporation			
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Apr – Dec 2009	4,579,487	420,763	$59.28 - $75.73	$6.32 - $15.10
Jan – Dec 2010	5,046,289	495,390	$62.34 - $83.00	$6.50 - $15.06
Jan – Dec 2011	4,435,039	436,510	$61.68 - $86.26	$6.50 - $14.62
Jan – Dec 2012	4,065,091	384,002	$61.70 - $87.63	$6.50 - $14.27
Jan – Nov 2013	3,090,000	-	$60.33 - $81.46	n/a
Total	21,215,906	1,736,665		

Derivatives conveyed to Whiting USA Trust I—In connection with the Company's conveyance on April 30, 2008 of a term net profits interest to the Trust and related sale of 11,677,500 Trust units to the public (as further explained in the note on Acquisitions and Divestitures), 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			
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Apr – Dec 2009	103,487	420,763	$76.00 - $136.57	$6.32 - $15.10
Jan – Dec 2010	126,289	495,390	$76.00 - $134.98	$6.50 - $15.06
Jan – Dec 2011	115,039	436,510	$74.00 - $140.15	$6.50 - $14.62
Jan – Dec 2012	105,091	384,002	$74.00 - $141.72	$6.50 - $14.27
Total	449,906	1,736,665		

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The 75.8% portion of Trust derivative contracts for 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			
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Apr – Dec 2009	324,145	1,317,926	$76.00 - $136.57	$6.32 - $15.10
Jan – Dec 2010	395,567	1,551,678	$76.00 - $134.98	$6.50 - $15.06
Jan – Dec 2011	360,329	1,367,249	$74.00 - $140.15	$6.50 - $14.62
Jan – Dec 2012	329,171	1,202,785	$74.00 - $141.72	$6.50 - $14.27
Total	1,409,212	5,439,638		

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, while the Company's remaining commodity derivative contracts were not designated as hedges, with gains and losses from changes in fair value recognized immediately in earnings. Effective April 1, 2009, however, the Company has elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges as of March 31, 2009 and has elected to discontinue hedge accounting prospectively. As a result, the Company will recognize all future gains and losses from prospective changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income.

At March 31 2009, accumulated other comprehensive income consisted of $59.8 million ($36.5 million after tax) of unrealized gains, representing the mark-to-market value of the Company's open commodity contracts designated as cash flow hedges as of the balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on April 1, 2009, such mark-to-market values at March 31, 2009 are frozen in accumulated other comprehensive income as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions affect earnings. The Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax gains of $20.6 million related to de-designated commodity hedges during the next twelve months.

Interest rate derivative contract—The Company has entered into an interest rate swap agreement to manage its exposure to interest rate risk on a portion of its fixed-rate borrowings. The interest rate swap effectively modifies the Company's exposure to interest rate risk by converting the fixed rate on $75.0 million of the Company's Senior Subordinated Notes due 2012 to a floating rate. This agreement involves the receipt of fixed rate amounts in exchange for floating rate interest payments over the life of the agreement without an exchange of the underlying notional amount. The interest rate swap is designated as a fair value hedge. Further information on the terms of the swap is discussed in the note above on Long-Term Debt.

SFAS 161—Effective January 1, 2009, the Company adopted Financial Accounting Standard Board ("FASB") Statement No. 161, Disclosure about Derivative Instruments and Hedging Activities – an amendment to FASB Statement No. 133 ("SFAS 161"). SFAS 161 expands interim and annual disclosures about derivative and hedging activities that are intended to better convey the purpose of derivative use and the risks managed. The adoption of SFAS 161 did not have an impact on the Company's consolidated financial statements, other than additional disclosures which are set forth below.

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All derivative instruments are recorded on the consolidated balance sheet at fair value. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets (in thousands).

	Asset Derivatives			Liability Derivatives		
Derivatives designated as SFAS 133 hedges:	Balance Sheet Location	Fair Value March 31, 2009	Fair Value December 31, 2008	Balance Sheet Location	Fair Value March 31, 2009	Fair Value December 31, 2008
Commodity contracts	Current derivative assets	$ 27,911	$ 30,198	Current derivative liabilities	$ 769	$ 4,784
Commodity contracts	Non-current derivative assets	16,199	13,163	Non-current derivative liabilities	6,437	9,224
Interest rate swap contract	Accounts receivable trade, net (1)	1,360	1,690			
Total derivatives designated as SFAS 133 hedges		$ 45,470	$ 45,051		$ 7,206	$ 14,008

(1) Amount was recorded in other long-term assets at December 31, 2008.

	Asset Derivatives			Liability Derivatives		
Derivatives not designated as SFAS 133 hedges:	Balance Sheet Location	Fair Value March 31, 2009	Fair Value December 31, 2008	Balance Sheet Location	Fair Value March 31, 2009	Fair Value December 31, 2008
Commodity contracts	Current derivative assets	$ 16,736	$ 16,582	Current derivative liabilities	$ 12,687	$ 12,570
Commodity contracts	Non-current derivative assets	23,015	24,941	Non-current derivative liabilities	17,447	18,907
Total derivatives not designated as SFAS 133 hedges		39,751	41,523		$ 30,134	$ 31,477
Total derivatives		$ 85,221	$ 86,574		$ 37,340	$ 45,485

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Commodity derivative contracts—The following tables summarize the effects of commodity derivatives instruments on the consolidated statements of income for the three months ended March 31, 2009 and 2008 (in thousands).

Derivatives in SFAS 133 Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion)		Location of Gain or (Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain or (Loss) Reclassified from AOCI into Income (Effective Portion)	
	March 31, 2009	March 31, 2008		March 31, 2009	March 31, 2008
Commodity contracts	$ 21,008	$ (21,377)	Gain (loss) on oil and natural gas hedging activities	$ 13,450	$ (22,912)

Derivatives in SFAS 133 Cash Flow Hedging Relationships	Location of (Gain) or Loss Recognized in Income on Derivative (Ineffective Portion)	Amount of (Gain) or Loss Recognized in Income on Derivative (Ineffective Portion)	
		March 31, 2009	March 31, 2008
Commodity contracts	(Gain) loss on mark-to-market derivatives	$ 22,866	$ -

Derivatives Not Designated as SFAS 133 Hedges	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative	
		March 31, 2009	March 31, 2008
Realized cash settlements on commodity contracts	(Gain) loss on mark-to-market derivatives	$ (1,530)	$ -
Unrealized (gains) losses on commodity contracts	(Gain) loss on mark-to-market derivatives	429	(2,937)
Total		$ (1,101)	$ (2,937)

Fair value hedge—The gain or loss on the hedged item ($75.0 million of fixed-rate borrowings under the Company's Senior Subordinated Notes due 2012) attributable to the hedged benchmark interest rate risk (risk of changes in the LIBOR swap rate) and the offsetting gain or loss on the related interest rate swap for the three months ended March 31, 2009 and 2008 are as follows (in thousands):

Income Statement Classification	Gain (Loss) on Swap		Gain (Loss) on Borrowing	
	March 31, 2009	March 31, 2008	March 31, 2009	March 31, 2008
Interest expense	$ (330)	$ 1,605	$ 330	$ (1,605)

There is no difference, or therefore ineffectiveness, between the gain (loss) on swap and gain (loss) on borrowing amounts in the above table because this swap meets the criteria to qualify for the "short cut" method of assessing effectiveness. Accordingly, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. In addition, the net swap settlements that accrue each period are also reported in interest expense.

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As of March 31, 2009, the total notional amount of the Company's receive-fixed/pay-variable interest rate swap was $75.0 million.

Contingent features in derivative instruments—None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's derivative contracts are high credit quality financial institutions that are lenders under Whiting's credit agreement. 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 the counterparty to secure contract performance obligations.

6. FAIR VALUE DISCLOSURES

Effective January 1, 2008, the Company adopted FASB Statement No. 157, Fair Value Measurements ("SFAS 157") which established 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 following table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of March 31, 2009, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

Fair Value of Financial Assets and Liabilities

	Level 1	Level 2	Level 3	March 31, 2009
Assets				
Accounts receivable, net (1)	$ -	$ 1,360	$ -	$ 1,360
Current portion of commodity derivative assets	-	44,647	-	44,647
Non-current commodity derivative assets	-	39,214	-	39,214
Total	$ -	$ 85,221	$ -	$ 85,221
Liabilities				
Current portion of derivative liabilities	$ -	$ 13,456	$ -	$ 13,456

Non-current commodity derivative liabilities		-		23,884		-	23,884
Long-term debt (1)		-		1,360		-	1,360
Total	$	-	$	38,700	$	-	$ 38,700

(1) Amount represents interest rate swap (see note on Long-Term Debt).

Fair Value of Financial Assets and Liabilities

	Level 1	Level 2	Level 3	December 31, 2008
Assets				
Current portion of commodity derivative assets	$ -	$ 46,780	$ -	$ 46,780
Non-current commodity derivative assets	-	38,104	-	38,104
Other long-term assets (1)	-	1,690	-	1,690
Total	$ -	$ 86,574	$ -	$ 86,574
Liabilities				
Current portion of commodity derivative liabilities	$ -	$ 17,354	$ -	$ 17,354
Non-current commodity derivative liabilities	-	28,131	-	28,131
Long-term debt (1)	-	1,690	-	1,690
Total	$ -	$ 47,175	$ -	$ 47,175

(1) Amount represents interest rate swap (see note on Long-Term Debt).

FSP 157-2—The Company elected to implement SFAS 157 with the one-year deferral permitted by FASB Staff Position No. FAS 157-2, Effective Date of FASB Statement No. 157 ("FSP 157-2"), issued February 2008, which defers the effective date of SFAS 157 for one year for certain nonfinancial assets and nonfinancial liabilities measured at fair value. Accordingly, the Company adopted SFAS 157 on January 1, 2009 for its nonfinancial assets and nonfinancial liabilities measured at fair value on a non-recurring basis. As it relates to the Company, this delayed adoption applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value; impaired oil and gas property assessments; and the initial recognition of asset retirement obligations for which fair value is used. This deferred adoption of SFAS 157, however, did not have an impact on the Company's consolidated financial statements or its disclosures.

7. STOCKHOLDERS' EQUITY

Common Stock Offering—In February 2009, the Company completed a public offering of its common stock under its existing shelf registration statement, selling 8,450,000 shares of common stock at a price of $29.00 per share and providing net proceeds of $234.9 million after underwriters' fees and offering expenses. The Company used the net offering proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement. Whiting plans to use the increased credit availability to fund a portion of the planned capital expenditures in its 2009 capital budget.

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Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the "Equity Plan"), pursuant to which two million shares of the Company's common stock have been reserved for issuance. No employee or officer participant may be granted options for more than 300,000 shares of common stock, stock appreciation rights relating to more than 300,000 shares of common stock, or more than 150,000 shares of restricted stock during any calendar year. As of March 31, 2009, 1,070,452 shares of common stock remained available for grant under the Plan.

Restricted Shares—Restricted stock awards for executive officers, directors and employees generally vest ratably over three years. 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 February 2007, 79,227 shares of restricted stock, subject to certain internal performance metrics in addition to the standard three-year service condition, were granted to executive officers under the Equity Plan. These internal performance conditions must be met in order for the stock awards to vest. It is therefore possible that no shares could vest in one or more of the three-year vesting periods. The Company recognizes compensation expense for awards subject to performance conditions when it becomes probable that these conditions will be achieved. However, any such compensation expense recognized is reversed if vesting does not actually occur.

In February 2009 and 2008, 209,649 shares and 74,542 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. The market-based conditions must be met in order for the stock awards to vest, and it is therefore possible that no shares could vest in one or more of the three-year vesting periods. However, the Company recognizes compensation expense for awards subject to market conditions regardless of whether it becomes probable that these conditions will be achieved or not, and compensation expense is not reversed if vesting does not actually occur.

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:

	2009	2008
Number of simulations	100,000	100,000
Expected volatility	70.0%	36.3%
Risk-free interest rate	1.33%	2.24%

The total grant date fair value of the market-based restricted stock as determined by the Monte Carlo valuation model was $1.4 million in February 2009 and $1.8 million in February 2008 and is recognized ratably over the three-year vesting period.

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The following table shows a summary of the Company's nonvested restricted stock as of March 31, 2009 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, 2009	258,764	$ 42.41
Granted	350,824	$ 14.39
Vested	(94,874)	$ 40.99
Forfeited	(3,133)	$ 42.90
Restricted stock awards nonvested, March 31, 2009	511,581	$ 21.16

As of March 31, 2009, there was $6.8 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 2.5 years.

Stock Options—In February 2009, 120,607 stock options 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 has not previously granted stock options, 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 using the U.S. Treasury yield curve rates with maturities similar to those of the expected term of the stock options. The following table summarizes the assumptions used in the estimate the grant date fair value of stock options awarded in February 2009:

	Stock Options 2009
Risk-free interest rate	2.0%
Expected volatility	58.1%
Expected term	6.0 yrs.
Dividend yield	-

The grant date fair value of the stock options awarded, as determined by the Black-Scholes valuation model, was $1.4 million and will be recognized ratably over the three-year vesting period.

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The following table shows a summary of the Company's stock options outstanding as of March 31, 2009 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
Options outstanding at January 1, 2009	-	-
Granted	120,607	$ 25.51
Exercised	-	-
Forfeited or expired	-	-
Options outstanding at March 31, 2009	120,607	$ 25.51

At March 31, 2009, no options were eligible for exercise. The weighted average grant-date fair value of options granted during 2009 was $11.85 per share. The 120,607 options outstanding in the table above have a remaining contractual term of 9.9 years and an aggregate intrinsic value of $0.04 million. Unrecognized compensation cost as of March 31, 2009 related to unvested stock option awards was $1.4 million, which is expected to be recognized over a period of 2.9 years.

Rights Agreement—In 2006, the Board of Directors of the Company declared a dividend of one preferred share purchase right (a "Right") for each outstanding share of common stock of the Company payable to the stockholders of record as of March 2, 2006. Each Right entitles the registered holder to purchase from the Company one one-hundredth of a share of Series A Junior Participating Preferred Stock, par value $0.001 per share ("Preferred Shares"), of the Company at a price of $180.00 per one one-hundredth of a Preferred Share, subject to adjustment. If any person becomes a 15% or more stockholder of the Company, then each Right (subject to certain limitations) will entitle its holder to purchase, at the Right's then current exercise price, a number of shares of common stock of the Company or of the acquirer having a market value at the time of twice the Right's per share exercise price. The Company's Board of Directors may redeem the Rights for $0.001 per Right at any time prior to the time when the Rights become exercisable. Unless the Rights are redeemed, exchanged or terminated earlier, they will expire on February 23, 2016.

8. EMPLOYEE BENEFIT PLANS

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. 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, 2009 and 2008 amounted to $2.0 million and $5.5 million, respectively, charged to general and administrative expense and $0.3 million and $0.9 million, respectively, charged to exploration expense.

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

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The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At March 31, 2009, the Company used three-year average historical NYMEX prices of $78.62 for crude oil and $7.56 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control (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 prices at March 31, 2009, 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 $80.1 million. This amount includes $12.9 million attributable to proved undeveloped oil and gas properties and $2.3 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2010. 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 for the three months ended March 31, 2009 (in thousands):

Production Participation Plan liability, January 1, 2009	$	66,166
Change in liability for accretion, vesting and changes in estimates		2,672
Reduction in liability for cash payments accrued and recognized as compensation expense		(2,276)
Production Participation Plan liability, March 31, 2009	$	66,562

The Company records the expense associated with changes in the present value of estimated future payments under the Plan as a separate line item in the consolidated statements of income. The amount recorded is not allocated to general and administrative expense or exploration expense because the adjustment of the liability is associated with the future net cash flows from the oil and gas properties rather than current period performance. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items (in thousands).

	Three Months Ended March 31,			
		2009		2008
General and administrative expense	$	345	$	5,277
Exploration expense		51		880
Total	$	396	$	6,157

401(k) Plan—The Company has a defined contribution retirement plan for all employees. The plan is funded by employee contributions and discretionary Company contributions. Employees vest in employer contributions at 20% per year of completed service.

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, 2009 and 2008 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% to income before income taxes primarily related to state income taxes and estimated permanent differences.

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The following table summarizes the components of the provision for income taxes (in thousands):

	Three Months Ended March 31, 2009	2008
Current portion of income tax expense:		
Federal	$ -	$ 1,642
State	(539)	67
Deferred portion of income tax expense	(25,505)	34,759
Total income tax expense	$ (26,044)	$ 36,468
Effective tax rates	37.3%	36.9%

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 acquired, additional information is obtained or as the tax environment changes.

10. RELATED PARTY TRANSACTIONS

Whiting USA Trust I—As a result of Whiting's retained ownership of 15.8%, or 2,186,389 units in Whiting USA Trust I, the Trust is a related party of the Company. The following table summarizes the related party receivable and payable balances between the Company and the Trust as of March 31, 2009 and December 31, 2008 (in thousands):

	March 31, 2009	December 31, 2008
Assets		
Unit distributions due from Trust (1)	$ 1,323	$ 1,596
Total	$ 1,323	$ 1,596
Liabilities		
Unit distributions payable to Trust (2)	$ 8,388	$ 10,120
Current portion of derivative liability	12,687	12,570
Non-current derivative liability	17,447	18,907
Total	$ 38,522	$ 41,597

(1) This amount represents Whiting's 15.8% interest in the net proceeds due from the Trust and is included within accounts receivable trade, net in the Company's consolidated balance sheets.

(2) This amount represents net proceeds from the Trust's underlying properties as well as realized cash settlements on Trust derivatives, that the Company has received between the last Trust distribution date and period end, but which the Company has not yet distributed to the Trust as of period end. Due to ongoing processing of Trust revenues and expenses after the respective period ends, the amount of Whiting's next scheduled distribution to the Trust, and the related distribution by the Trust to its unit holders, will differ from this amount. This amount is included within accounts payable in the Company's consolidated balance sheet.

For the three months ended March 31, 2009 and year ended December 31, 2008, Whiting paid $11.1 million and $57.8 million, respectively, net of state tax withholdings, in distributions to the Trust under the net profits interest and received $1.7 million and $9.0 million, respectively, in distributions back from the Trust pursuant to its retained ownership in 2,186,389 Trust units.

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Tax Sharing Liability—Prior to Whiting's initial public offering in November 2003, it was a wholly-owned indirect subsidiary of Alliant Energy Corporation ("Alliant Energy"), a holding company whose primary businesses are utility companies. When the transactions discussed below were entered into, Alliant Energy was a related party of the Company. As of December 31, 2004 and thereafter, Alliant Energy was no longer a related party.

In connection with Whiting's initial public offering in November 2003, the Company entered into a Tax Separation and Indemnification Agreement with Alliant Energy. Pursuant to this agreement, the Company and Alliant Energy made a tax election with the effect that the tax bases of Whiting's assets were increased to the deemed purchase price immediately prior to such initial public offering. Whiting has adjusted deferred taxes on its balance sheet to reflect the new tax bases of its assets. The additional bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by Whiting.

Under this agreement, the Company has agreed to pay to Alliant Energy 90% of the future tax benefits the Company realizes annually as a result of this step-up in tax basis for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing the Company's actual taxes to the taxes that would have been owed by the Company had the increase in basis not occurred. In 2014, Whiting 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. The Company has estimated total payments to Alliant will approximate $34.5 million on an undiscounted basis.

During the first quarter of 2009, the Company did not make any payments under this agreement but did recognize $0.4 million of interest expense. The Company's estimated payment of $2.1 million to be made in 2009 under this agreement is reflected as a current liability at March 31, 2009 and December 31, 2008.

The Tax Separation and Indemnification Agreement provides that if tax rates were to increase or decrease, the resulting tax benefit or detriment would cause a corresponding adjustment of the tax sharing liability. For purposes of this calculation, management has assumed that no such future changes will occur during the term of this agreement.

The Company periodically evaluates its estimates and assumptions as to future payments to be made under this agreement. If non-substantial changes (less than 10% on a present value basis) are made to the anticipated payments owed to Alliant Energy, a new effective interest rate is determined for this debt based on the carrying amount of the liability as of the modification date and based on the revised payment schedule. However, if there are substantial changes to the estimated payments owed under this agreement, then a gain or loss is recognized in the consolidated statements of income during the period in which the modification has been made.

Alliant Energy Guarantee—The Company holds a 6% working interest in three offshore platforms in California and the related onshore plant and equipment. Alliant Energy has guaranteed the Company's obligation in the abandonment of these assets.

11. COMMITMENTS AND CONTINGENCIES

Non-cancelable Leases—The Company leases 107,400 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through 2013 and an additional 46,700 square feet of office space in Midland, Texas until 2012. Rental expense for the first quarter of 2009 and 2008 was $0.7 million and $0.5 million, respectively.

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Minimum lease payments under the terms of non-cancelable operating leases as of March 31, 2009 are as follows (in thousands):

2009	$	1,893
2010		2,677
2011		3,383
2012		2,931
2013		2,382
Total	$	13,266

Purchase Contracts—The Company has entered into two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement expiring in December 2014, whereby the Company has committed to buy certain volumes of CO_2 for a fixed fee subject to annual escalation. The purchase agreements are with different suppliers, and the CO_2 is for use in the Company's enhanced recovery projects in Oklahoma and Texas. Under the terms of the agreements, the Company is obligated to purchase a minimum daily volume of CO_2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when delivery was to have occurred. The CO_2 volumes planned for use in the Company's enhanced recovery projects currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, the Company expects to avoid any payments for deficiencies. As of March 31, 2009, future commitments under the purchase agreements amounted to $143.6 million through 2014.

Drilling Contracts—The Company currently has seven drilling rigs under long-term contract, of which two drilling rigs expire in 2009, two in 2010, one in 2011, one in 2012 and one in 2013. All of these rigs are operating in the Rocky Mountains region. As of March 31, 2009, these drilling contracts had total commitments of $117.1 million. Included in this total obligation of $117.1 million is $3.7 million of rig termination fees that the Company accrued as a current payable at March 31, 2009 for the cancellation of long-term contracts on three drilling rigs and one workover rig. As of March 31, 2009, early termination of the remaining contracts would require additional termination penalties of $68.3 million, which would be in lieu of paying the remaining drilling commitments of $113.4 million. Other drilling rigs working for the Company are not under long-term contracts but instead are under contracts that can be terminated at the end of the well that is currently being drilled.

Litigation—The Company is subject to litigation, claims and governmental and regulatory proceedings arising in the ordinary course of business. It is the opinion of the Company's management that all claims and litigation involving the Company are not likely to have a material adverse effect on its consolidated financial position, cash flows or results of operations.

12. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. We are currently assessing the impact that the adoption will have on our disclosures, operating results, statement of financial position and statement of cash flows.

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In April 2009, the FASB issued Staff Position ("FSP") No. FAS 157-4, Determining Fair Value When the Volume or Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly ("FSP 157-4"). The adoption of FSP 157-4 is not expected to have an impact on the Company's consolidated financial statements, other than additional disclosures. FSP 157-4 provides additional guidance for estimating fair value in accordance with SFAS No. 157 when the volume and level of activity for the asset or liability have significantly decreased and requires that companies provide interim and annual disclosures of the inputs and valuation technique(s) used to measure fair value. FSP 157-4 is effective for interim and annual reporting periods ending after June 15, 2009 and is to be applied prospectively.

In April 2009, the FASB issued FSP No. 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments ("FSP 107-1"). The adoption of FSP 107-1 is not expected to have an impact on the Company's consolidated financial statements, other than additional disclosures. FSP 107-1 requires disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. FSP 107-1 is effective for interim and annual reporting periods ending after June 15, 2009.

13. SUBSEQUENT EVENT

On April 28, 2009, Whiting Oil and Gas entered into a Fourth Amended and Restated Credit Agreement with its bank syndicate, which replaced the existing credit facility. This amended credit agreement increased the Company's borrowing base under the facility from $900.0 million to $1.1 billion and extended the principal repayment date to April 2012. 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.

The credit agreement provides for interest only payments until April 2012, 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.

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	1.1250%	2.00%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.1375%	2.25%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.6250%	2.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.8750%	2.75%
Greater than or equal to 0.90 to 1.0	2.1250%	3.00%

Under the credit agreement, 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.

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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. The credit agreement requires the Company, as of the last day of any quarter, (i) to not exceed a total debt to EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 4.5 to 1.0 for quarters ending prior to and on September 30, 2010, 4.25 to 1.0 for quarters ending December 31, 2010 to June 30, 2011 and 4.0 to 1.0 for quarters ending September 30, 2011 and thereafter, (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement) of not less than 1.0 to 1.0 and (iii) to not exceed a senior secured debt to EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 2.75 to 1.0 for quarters ending prior to and on December 31, 2009 and 2.5 to 1.0 for quarters ending March 31, 2010 and thereafter. Except for limited exceptions, the credit agreement restricts the Company's ability to make any dividends or distributions on its common stock or principal payments on its senior notes.

The obligations of Whiting Oil and Gas under the credit agreement are secured by a first lien on substantially all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation and its wholly-owned subsidiary, Equity Oil Company, have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for its guarantee, and Equity Oil Company has mortgaged substantially all of its properties included in the borrowing base for the credit agreement as security for its guarantee.

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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 Whiti Petroleum Corporation, together with its consolidated subsidiaries, Whiting Oil and Gas Corporation, Equity Oil Company 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 oil and gas 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 balance between exploration and development programs and 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.

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Oil and natural gas prices have fallen significantly since their third quarter 2008 levels. For example, the daily average NYMEX oil price was $118.13 per Bbl for the third quarter of 2008, $58.75 per Bbl for the fourth quarter of 2008, and $43.21 per Bbl for the first quarter of 2009. Similarly, daily average NYMEX natural gas prices have declined from $10.27 per Mcf for the third quarter of 2008 to $6.96 per Mcf for the fourth quarter of 2008 and $4.92 for the first quarter of 2009. 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.

First Quarter 2009 Highlights and Future Considerations

Common Stock Offering. In February 2009, we completed a public offering of our common stock under our existing shelf registration statement, selling 8,450,000 shares of common stock at a price of $29.00 per share and providing net proceeds of $234.9 million after underwriters' fees and offering expenses. We used the net offering proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement, and we plan to use the increased credit availability to fund a portion of the planned capital expenditures in our 2009 capital budget.

Operational Highlights. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken formation. Production in this area was affected by winter weather during the first quarter of 2009, which caused delays in trucking operations and well completion activity. In the Parshall field, net production averaged 5.4 MBOE/d in the first quarter of 2009, a 27% decrease from 7.3 MBOE/d in the fourth quarter of 2008. Net production in the Parshall field increased 70% from a net 3.0 MBOE/d in March 2008 to a net 5.1 MBOE/d in March 2009. Despite these weather issues, first quarter 2009 net production in the Sanish field averaged 8.9 MBOE/d, an 11% increase from 8.0 MBOE/d in the fourth quarter of 2008. Net production in the Sanish field increased 740% from a net 1.2 MBOE/d in March 2008 to a net 9.9 MBOE/d in March 2009.

We continue to have significant development and related infrastructure activity on the Postle and North Ward Estes fields acquired in 2005, which have resulted in reserve and production increases. Our expansion of the CO_2 flood at both fields continues to generate positive results. During the first quarter of 2009, we incurred $53.0 million of development expenditures on these two projects.

The Postle field is located in Texas County, Oklahoma. Four of our five producing units are currently under active CO_2 enhanced recovery projects. As of April 20, 2009, we were injecting 147 MMcf/d of CO_2 in this field. Production from the field has increased 27% from a net 6.2 MBOE/d in March 2008 to a net 7.9 MBOE/d in March 2009. Operations are under way to expand CO_2 injection into the northern part of the fourth unit, HMU, and to optimize flood patterns in the existing CO_2 floods. These expansion projects include the restoration of shut-in wells and the drilling of new producing and injection wells.

The North Ward Estes field is responding positively to our water and CO_2 floods, which we initiated in Phase I during May 2007. In early March 2009, we began Phase II of the project. As of April 20, 2009, we were injecting 170 MMcf/d of CO_2 in this field. Production from the field has increased 23% from a net 5.2 MBOE/d in March 2008 to a net 6.4 MBOE/d in March 2009. In this field, we are developing new and reactivated wells for water and CO_2 injection and production purposes. Additionally, we plan to install oil, gas and water processing facilities in five phases through 2015, and we estimate that the first three phases will be substantially complete by December 2009.

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2009 Capital Budget and Major Development Areas. Our current 2009 capital budget for exploration and development expenditures is $420.6 million, which we expect to fund with net cash provided by our operating activities and a portion of the proceeds from the common stock offering we completed in February 2009. To the extent net cash provided by operating activities or oil and natural gas prices are lower than currently anticipated, we would adjust our capital budget accordingly. If net cash provided by operating activities is higher than currently anticipated, we plan to reduce debt levels. Our 2009 capital budget currently is allocated among our major development areas as indicated in the chart below.

Development Area	2009 Planned Capital Expenditures (In millions)
Northern Rockies	$ 227.9
Enhanced Oil Recovery Projects (1)	122.9
Central Rockies	26.0
Permian Basin	13.5
Exploration and early rig termination (2)	30.3
Total	$ 420.6

(1) 2009 planned capital expenditures at our CO2 projects include $36.9 million for purchased CO2 at North Ward Estes and $15.3 million for Postle CO2 purchases.

(2) Comprised primarily of exploration salaries, $6.2 million of early rig termination fees, lease delay rentals and seismic surveys.

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Results of Operations

Three Months Ended March 31, 2009 Compared to Three Months Ended March 31, 2008

Selected Operating Data:	Three Months Ended March 31, 2009		Three Months Ended March 31, 2008	
Net production:				
Oil (MMBbls)		3.6		2.6
Natural gas (Bcf)		7.9		6.9
Total production (MMBOE)		4.9		3.7
Net sales (in millions):				
Oil (1)	$	116.3	$	232.4
Natural gas (1)		29.9		54.3
Total oil and natural gas sales	$	146.2	$	286.7
Average sales prices:				
Oil (per Bbl)	$	32.55	$	89.58
Effect of oil hedges on average price (per Bbl)		4.10		(8.83)
Oil net of hedging (per Bbl)	$	36.65	$	80.75
Average NYMEX price	$	43.21	$	97.96
Natural gas (per Mcf)	$	3.78	$	7.89
Effect of natural gas hedges on average price (per Mcf)		0.05		-
Natural gas net of hedging (per Mcf)	$	3.83	$	7.89
Average NYMEX price	$	4.92	$	8.03
Cost and expense (per BOE):				
Lease operating expenses	$	12.47	$	14.89
Production taxes	$	1.95	$	4.73
Depreciation, depletion and amortization expense	$	20.46	$	13.50
General and administrative expenses	$	1.84	$	3.10

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased $140.6 million to $146.2 million in the first quarter of 2009 compared to the first quarter of 2008. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 38% between periods, while our natural gas sales volumes increased 15%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area in addition to increased production at our two large CO2 projects, Postle and North Ward Estes. Oil production from the Bakken increased 940 MBbl compared to the first quarter of 2008, while Postle oil production increased 120 MBbl and North Ward Estes oil production increased 130 MBbl over the same prior year period. These production increases were partially offset by the Whiting USA Trust I (the "Trust") divestiture, which decreased oil production by 205 MBbl, as well as normal field production decline. The gas volume increase between periods was primarily the result of incremental gas production of 1,220 MMcf from the Flat Rock acquisition, which we completed on May 30, 2008, higher production in the Boies Ranch area of 840 MMcf, and new production of 700 MMcf from wells drilled in the Gulf Coast region. These production increases were partially offset by the Trust divestiture, which decreased gas production by 1,015 MMcf, as well as normal field production decline. Offsetting the production increases were decreases in average sales prices. Our average price for oil before effects of hedging decreased 64% between periods, and our average price for natural gas before effects of hedging decreased 52%.

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Gain (Loss) on Oil and Natural Gas Hedging Activities. Realized cash settlements on commodity derivatives that we have designated as cash flow hedges are recognized as gain (loss) on oil and natural gas hedging activities. During the first quarter of 2009, we incurred cash settlement gains of $13.5 million on such crude oil hedges. During the first quarter of 2008, we incurred realized cash settlement losses of $22.9 million on crude oil derivatives designated as cash flow hedges. None of our natural gas derivatives were designated as cash flow hedges during the first quarter of 2009 or 2008. Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges as of March 31, 2009 and have elected to discontinue hedge accounting prospectively. See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas derivatives as of April 1, 2009.

Amortization of Deferred Gain on Sale. In connection with the sale of 11,677,500 Trust units to the public and related oil and gas property conveyance on April 30, 2008, we recognized a deferred gain on sale of $100.1 million. This deferred gain is amortized to income over the life of the Trust on a units-of-production basis. For the three months ended March 31, 2009, we recognized $4.1 million in income as amortization of deferred gain on sale.

Lease Operating Expenses. Our lease operating expenses during the first quarter of 2009 were $61.0 million, a $5.2 million or 9% increase over the same period in 2008. Our lease operating expenses per BOE decreased from $14.89 during the first quarter of 2008 to $12.47 during the first quarter of 2009. The decrease of 16% on a BOE basis was primarily caused by increased production during the first quarter of 2009, partially offset by a high level of workover activity. Workovers amounted to $14.1 million in the first quarter of 2009, as compared to $3.9 million in the first quarter of 2008. The increase in workover activity primarily relates to our two CO_2 projects, which are evolving past the construction and start-up phases and moving into an ongoing maintenance and repair phase that involves a significantly higher number of producing and injection wells.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for the first quarter of 2009 and 2008 were 6.5% and 6.2%, respectively, of oil and natural gas sales. Our production tax rate for the first quarter of 2009 was greater than the rate for same period in 2008 mainly due to successful wells completed in the North Dakota Bakken area during 2008, which carry an 11.5% production tax rate.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $49.5 million as compared to the first quarter of 2008. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended March 31, 2009	2008
Depletion	$ 97,005	$ 49,044
Depreciation	831	751
Accretion of asset retirement obligations	2,198	716
Total	$ 100,034	$ 50,511

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DD&A increased $49.5 million primarily due to $48.0 million in higher depletion expense between periods. Of this $48.0 million increase in depletion, $15.0 million related to higher oil and gas volumes produced during the first quarter of 2009, while $33.0 million related to our higher depletion rate in 2009. On a BOE basis, our DD&A rate increased by 52% from $13.50 for the first quarter of 2008 to $20.46 for the first quarter of 2009. The primary factors causing this rate increase were (i) $902.4 million in drilling expenditures incurred during the past twelve months, (ii) net oil and natural gas reserve reductions of 11.6 MMBOE during 2008, which were primarily attributable to a 39.0 MMBOE downward revision for lower oil and natural gas prices at December 31, 2008, and (iii) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred.

Exploration and Impairment Costs. Our exploration and impairment costs increased $6.3 million, as compared to the first quarter of 2008. The components of exploration and impairment costs were as follows (in thousands):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Exploration	$ 12,633	$ 8,412
Impairment	4,681	2,572
Total	$ 17,314	$ 10,984

Exploration costs increased $4.2 million during the first quarter of 2009 as compared to the same period in 2008 primarily due to rig termination fees recognized in the first quarter of 2009, partially offset by a decrease in geological and geophysical ("G&G") activity. Rig termination fees totaled $6.2 million during the first quarter of 2009, while we did not pay any rig termination fees in the first quarter of 2008. G&G costs amounted to $3.3 million during the first quarter of 2009, as compared to $5.1 million during the first quarter of 2008. We did not drill any exploratory dry holes during the first quarter of 2009 or 2008. The impairment charges in the first quarter of 2009 and 2008 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. As of March 31, 2009, the amount of unproved properties being amortized totaled $81.6 million, as compared to $55.0 million as of March 31, 2008.

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, 2009	Three Months Ended March 31, 2008
General and administrative expenses	$ 20,996	$ 21,112
Reimbursements and allocations	(12,016)	(9,497)
General and administrative expense, net	$ 8,980	$ 11,615

General and administrative expense before reimbursements and allocations decreased $0.1 million to $21.0 million during the first quarter of 2009. The largest component of the decrease related to $4.1 million in lower accrued distributions under our Production Participation Plan ("Plan") between periods due to a lower level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula) resulting from lower oil and natural gas prices during the first quarter of 2009 as compared to the same period of 2008. These lower accrued Plan distributions were partially offset by $2.6 million in additional employee compensation for personnel hired during the past twelve months as well as general pay increases. The increase in reimbursements and allocations in 2009 was caused by higher salary costs. Our general and administrative expenses as a percentage of oil and natural gas sales increased from 4% for the first quarter of 2008 to 6% for the first quarter of 2009. This increase was primarily due to decreased oil and gas sales revenue as a result of lower oil and natural gas prices.

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

	Three Months Ended March 31,	
	2009	2008
Senior Subordinated Notes	$ 10,768	$ 11,080
Credit Agreement	3,213	3,917
Amortization of debt issue costs and debt discount	1,173	1,217
Other	450	353
Capitalized interest	(924)	(1,021)
Total interest expense	$ 14,680	$ 15,546

The decrease in interest expense of $0.9 million between periods was mainly due to lower interest rates on borrowings under our credit facility, partially offset by a higher level of debt outstanding under our credit facility during the first quarter of 2009. Our weighted average effective cash interest rate was 4.6% during the first quarter of 2009 compared to 6.6% during the first quarter of 2008. Our weighted average debt outstanding during the first quarter of 2009 was $1,215.8 million versus $901.8 million for the first quarter of 2008. After inclusion of non-cash interest costs for the amortization of debt issue costs, debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 5.0% during the first quarter of 2009 compared to 7.1% during the first quarter of 2008.

Change in Production Participation Plan Liability. For the three months ended March 31, 2009, this non-cash expense was $0.4 million, a decrease of $5.8 million as compared to the same period in 2008. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2010 under our Plan. Although payments take place over the life of the Plan's oil and gas properties, which for some properties is over 20 years, we expense the present value of estimated future payments over the Plan's five-year vesting period. This expense in 2009 and 2008 primarily reflected (i) changes to future cash flow estimates stemming from the volatile commodity price environment during the past year, (ii) recent drilling activity and property acquisitions, and (iii) employees' continued vesting in the Plan. The average NYMEX prices used to estimate this liability decreased by $0.82 for crude oil and $0.22 for natural gas for the three months ended March 31, 2009, as compared to increases of $3.23 for crude oil and $0.19 for natural gas over the same period in 2008. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

(Gain) Loss on Mark-to-Market Derivatives. During 2008, we entered into commodity derivative contracts that we did not designate as cash flow hedges. Accordingly, these derivative contracts 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 (gain) loss on mark-to-market derivatives. During the first quarter of 2009, we recognized $0.4 million in unrealized mark-to-market derivative losses and $1.5 million in realized cash settlement gains. We also recognized a loss of $22.9 million for the ineffective portion of changes in fair value on our commodity derivatives designated as cash flow hedges. During the first quarter of 2008, we recognized $2.9 million in unrealized mark-to-market derivative gains on contracts not designated as cash flow hedges.

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Income Tax Expense (Benefit). Income tax benefit totaled $26.0 million for the first quarter of 2009, versus $36.5 million of income tax expense for the first quarter of 2008. Our effective income tax rate increased from 36.9% for the first quarter of 2008 to 37.3% for the first quarter of 2009. Our effective income tax rate was higher in 2009 due to tax benefits resulting from changes to state apportionment.

Net Income (Loss). Net income (loss) decreased from $62.3 million in income during the first quarter of 2008 to a $43.8 million loss during the first quarter of 2009. The primary reasons for this decrease include a 55% decrease in oil prices (net of hedging); a 51% decrease in natural gas prices (net of hedging); higher lease operating expenses, DD&A, and exploration and impairment; and unrealized losses on commodity derivatives. These negative factors were partially offset by a 31% increase in equivalent volumes sold; lower production taxes, general and administrative expenses, interest expense, Production Participation Plan expense and income taxes; and amortization of deferred gain on sale during the first quarter of 2009.

Liquidity and Capital Resources

Overview. At March 31, 2009, our debt to total capitalization ratio was 37.1%, we had $7.0 million of cash on hand and $2,019.2 million of stockholders' equity. At December 31, 2008, our debt to total capitalization ratio was 40.7%, we had $9.6 million of cash on hand and $1,808.8 million of stockholders' equity. In the first quarter of 2009, we generated $34.2 million of cash provided by operating activities, a decrease of $88.2 million over the same period in 2008. Cash provided by operating activities decreased primarily due to lower average sales prices for both crude oil and natural gas, partially offset by higher oil and gas volumes produced in the first quarter of 2009. We also generated $184.9 million from financing activities consisting of $234.9 million in net proceeds received from the issuance of our common stock, offset by net repayments under our credit agreement totaling $50.0 million. Cash flows from operating and financing activities were used to finance $201.2 million of drilling and development expenditures paid in the first quarter of 2009 and $20.7 million of cash acquisition capital expenditures. The following chart details our exploration and development expenditures incurred by region during the first quarter of 2009 (in thousands):

	Drilling and Development Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 101,266	$ 7,463	$ 108,729	62%
Permian Basin	48,133	3,584	51,717	29%
Mid-Continent	12,476	266	12,742	7%
Gulf Coast	1,069	1,320	2,389	1%
Michigan	839	-	839	1%
Total incurred	163,783	12,633	176,416	100%
Decrease in accrued capital expenditures	37,368	-	37,368	
Total paid	$ 201,151	$ 12,633	$ 213,784	

We continually evaluate our capital needs and compare them to our capital resources. Our current 2009 capital budget for exploration and development expenditures is $420.6 million, which we expect to fund with net cash provided by our operating activities and a portion of the proceeds from the common stock offering we completed in February 2009. Our 2009 capital budget of $420.6 million, however, represents a significant decrease from the $947.4 million incurred on exploration and development expenditures during 2008. This reduced capital budget is in response to significantly lower oil and natural gas prices experienced during the fourth quarter of 2008 and continuing into 2009. Although we have no specific budget for property acquisitions in 2009, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that should attractive acquisition opportunities arise or exploration and development expenditures exceed $420.6 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 and development 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.

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Credit Agreement. As of March 31, 2009, Whiting Oil and Gas Corporation, ("Whiting Oil and Gas"), our wholly-owned subsidiary, had a $1.2 billion credit agreement with a syndicate of banks that had a borrowing base of $900.0 million with $327.2 million of available borrowing capacity, which is net of $570.0 million in borrowings and $2.8 million in letters of credit outstanding. At March 31, 2009, the effective weighted average interest rate on the outstanding principal balance under the credit facility was 1.8% and we were in compliance with our covenants under the credit agreement.

On April 28, 2009, we entered into a Fourth Amended and Restated Credit Agreement with our bank syndicate, which replaced the existing credit facility. This amended credit agreement increased our borrowing base under the facility from $900.0 million to $1.1 billion and extended the principal repayment date to April 2012. 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 our 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 April 27, 2009, Whiting Oil and Gas had borrowed $610.0 million and had $2.8 million of letters of credit outstanding under the credit agreement.

The credit agreement provides for interest only payments until April 2012, 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.

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	1.1250%	2.00%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.1375%	2.25%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.6250%	2.50%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.8750%	2.75%
Greater than or equal to 0.90 to 1.0	2.1250%	3.00%

Under the credit agreement, we also incur commitment fees of 0.50% on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base.

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. The credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 4.5 to 1.0 for quarters ending prior to and on September 30, 2010, 4.25 to 1.0 for quarters ending December 31, 2010 to June 30, 2011 and 4.0 to 1.0 for quarters ending September 30, 2011 and thereafter, (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement) of not less than 1.0 to 1.0 and (iii) to not exceed a senior secured debt to EBITDAX ratio (as defined in the credit agreement) for the last four quarters of 2.75 to 1.0 for quarters ending prior to and on December 31, 2009 and

2.5 to 1.0 for quarters ending March 31, 2010 and thereafter. Except for limited exceptions, the credit agreement restricts our ability to make any dividends or distributions on our common stock or principal payments on our senior notes.

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The obligations of Whiting Oil and Gas under the credit agreement are secured by a first lien on substantially all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. We and our subsidiary Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. We have pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for our guarantee, and Equity Oil Company has mortgaged substantially all of its properties included in the borrowing base for the credit agreement as security for its guarantee.

Senior Subordinated Notes. In October 2005, we issued at par $250.0 million of 7% Senior Subordinated Notes due 2014. In April 2005, we issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount is being amortized to interest expense over the term of these notes. In May 2004, we issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount is being amortized to interest expense over the term of these notes.

The notes are unsecured obligations of ours and are subordinated to all of our senior debt, which currently consists of Whiting Oil and Gas' credit agreement. 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, 2009. 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. Our wholly-owned operating subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company, have fully, unconditionally, jointly and severally guaranteed our obligations under the notes.

Shelf Registration Statement. We have on file with the SEC a universal shelf registration statement to allow us to offer an indeterminate amount of securities in the future. Under the registration statement, we may periodically offer from time to time debt securities, common stock, preferred stock, warrants and other securities or any combination of such securities in amounts, prices and on terms announced when and if the securities are offered. However, we recognize that the issuance of additional securities in periods of market volatility may be less likely. The specifics of any future offerings, along with the use of proceeds of any securities offered, will be described in detail in a prospectus supplement at the time of any such offering.

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liabilities 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, 2009 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

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Contractual Obligations	Payments due by period Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (a)	$ 1,190,000	$ -	$ 570,000	$ 620,000	$ -
Cash interest expense on debt (b)	198,064	54,786	93,009	50,269	-
Asset retirement obligation (c)	69,691	9,853	2,929	8,812	48,097
Tax sharing liability (d)	24,096	2,112	3,787	3,261	14,936
Derivative contract liability fair value (e)	37,340	13,456	16,214	7,670	-
Purchasing obligations (f)	143,588	27,074	63,536	47,040	5,938
Drilling rig contracts (g)	117,052	48,142	58,479	10,431	-
Operating leases (h)	13,266	2,525	6,245	4,496	-
Total	$ 1,793,097	$ 157,948	$ 814,199	$ 751,979	$ 68,971

(a) Long-term debt consists of the 7.25% Senior Subordinated Notes due 2012 and 2013, the 7% Senior Subordinated Notes due 2014 and the outstanding borrowings under our credit agreement, and assumes no principal repayment until the due date of the instruments. In April 2009, we entered into a Fourth Amended and Restated Credit Agreement, which replaces our existing credit facility and extends the principal repayment due date to April 2012.

(b) Cash interest expense on the 7.25% Senior Subordinated Notes due 2012 and 2013 and the 7% Senior Subordinated Notes due 2014 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 1.8%.

(c) 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.

(d) 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.

(e) The above derivative obligation at March 31, 2009 consists of a $30.1 million payable to Whiting USA Trust I ("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 above derivative obligation at March 31, 2009 also consists of a $7.2 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 and natural gas price fluctuations. With respect to our open derivative contracts at March 31, 2009 with certain counterparties, the forward price curves for crude oil and natural gas generally exceeded the price curves that were 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 and commodity price risk.

(f) We have two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement 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 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. The CO2 volumes planned for use on the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, we expect to avoid any payments for deficiencies.

(g) We currently have seven drilling rigs under long-term contract, of which two drilling rigs expire in 2009, two in 2010, one in 2011, one in 2012 and one in 2013. All of these rigs are operating in the Rocky Mountains region. Included in the above obligation is $3.7 million of rig termination fees that we accrued as a current payable at March 31, 2009 for the cancellation of long-term contracts on three drilling rigs and one workover rig. As of March 31, 2009, early termination of the remaining contracts would require additional termination penalties of $68.3 million, which would be in lieu of paying the remaining drilling commitments of $113.4 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 drilling time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(h) We lease 107,400 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.

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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

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. We are currently assessing the impact that the adoption will have on our disclosures, operating results, statement of financial position and statement of cash flows.

In April 2009, the FASB issued Staff Position (“FSP”) No. FAS 157-4, Determining Fair Value When the Volume or Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly ("FSP 157-4"). The adoption of FSP 157-4 is not expected to have an impact on our consolidated financial statements, other than additional disclosures. FSP 157-4 provides additional guidance for estimating fair value in accordance with SFAS No. 157 when the volume and level of activity for the asset or liability have significantly decreased and requires that companies provide interim and annual disclosures of the inputs and valuation technique(s) used to measure fair value. FSP 157-4 is effective for interim and annual reporting periods ending after June 15, 2009 and is to be applied prospectively.

In April 2009, the FASB issued FSP No. 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments (“FSP 107-1”). The adoption of FSP 107-1 is not expected to have an impact on our consolidated financial statements, other than additional disclosures. FSP 107-1 requires disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. FSP 107-1 is effective for interim and annual reporting periods ending after June 15, 2009.

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, 2008.

Effects of Inflation and Pricing

We experienced increased costs during 2008 due to increased demand for oil field products and services. The oil and gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry 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 have not adjusted downward in proportion. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, 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.

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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 "sho the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

These risks and uncertainties include, but are not limited to: declines in oil or natural gas prices; impacts of the global recession and financial crisis; 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 Whiting Oil and Gas Corporation's 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; 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; 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, 2008. 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

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, 2008 and have not materially changed since that report was filed.

Our outstanding hedges as of April 1, 2009 are summarized below:

Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	04/2009 to 06/2009	518,000	$55.12/$65.68
Crude Oil	07/2009 to 09/2009	496,000	$57.12/$69.55
Crude Oil	10/2009 to 12/2009	478,000	$61.04/$74.89
Crude Oil	01/2010 to 03/2010	430,000	$60.27/$74.81
Crude Oil	04/2010 to 06/2010	415,000	$62.69/$80.09
Crude Oil	07/2010 to 09/2010	405,000	$60.28/$76.98
Crude Oil	10/2010 to 12/2010	390,000	$60.29/$78.23
Crude Oil	01/2011 to 03/2011	360,000	$60.32/$80.33
Crude Oil	04/2011 to 06/2011	360,000	$60.32/$80.33
Crude Oil	07/2011 to 09/2011	360,000	$60.32/$80.33
Crude Oil	10/2011 to 12/2011	360,000	$60.32/$80.33
Crude Oil	01/2012 to 03/2012	330,000	$60.35/$81.70
Crude Oil	04/2012 to 06/2012	330,000	$60.35/$81.70
Crude Oil	07/2012 to 09/2012	330,000	$60.35/$81.70
Crude Oil	10/2012 to 12/2012	330,000	$60.35/$81.70
Crude Oil	01/2013 to 03/2013	290,000	$60.40/$81.66
Crude Oil	04/2013 to 06/2013	290,000	$60.40/$81.66
Crude Oil	07/2013 to 09/2013	290,000	$60.40/$81.66
Crude Oil	10/2013	290,000	$60.40/$81.66
Crude Oil	11/2013	190,000	$59.29/$78.43

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I (as further explained above in the note on Acquisitions and Divestitures), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 1,859 MBbls of crude oil and 7,176 MMcf of natural gas from 2009 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):

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Conveyed to Whiting USA Trust I

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	04/2009 to 06/2009	48,794	$76.00/$137.55
Crude Oil	07/2009 to 09/2009	47,510	$76.00/$136.41
Crude Oil	10/2009 to 12/2009	46,240	$76.00/$135.72
Crude Oil	01/2010 to 03/2010	45,084	$76.00/$135.09
Crude Oil	04/2010 to 06/2010	43,978	$76.00/$134.85
Crude Oil	07/2010 to 09/2010	42,966	$76.00/$134.89
Crude Oil	10/2010 to 12/2010	41,924	$76.00/$135.11
Crude Oil	01/2011 to 03/2011	40,978	$74.00/$139.68
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
Crude Oil	10/2012 to 12/2012	35,028	$74.00/$142.21
Natural Gas	04/2009 to 06/2009	201,263	$6.00/$14.85
Natural Gas	07/2009 to 09/2009	192,870	$6.00/$15.60
Natural Gas	10/2009 to 12/2009	185,430	$7.00/$14.85
Natural Gas	01/2010 to 03/2010	178,903	$7.00/$18.65
Natural Gas	04/2010 to 06/2010	172,873	$6.00/$13.20
Natural Gas	07/2010 to 09/2010	167,583	$6.00/$14.00
Natural Gas	10/2010 to 12/2010	162,997	$7.00/$14.20
Natural Gas	01/2011 to 03/2011	157,600	$7.00/$17.40
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

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 2009 crude oil contracts listed in both tables above, a hypothetical $1.00 change in the NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2009 of $4.6 million. For the 2009 natural gas contracts listed above, a hypothetical $0.10 change in the NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in our gain (loss) on mark-to-market derivatives in 2009 of $0.04 million.

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In a 1997 acquisition of non-operated properties, we became subject to the operator's fixed price gas sales contract with end users for a portion of the natural gas we produce in Michigan. This contract has built-in pricing escalators of 4% per year. Our estimated future production volumes to be sold under the fixed pricing terms of this contract as of April 1, 2009 are summarized below:

Commodity	Remaining Period	Monthly Volume (MMBtu)	2009 Price Per MMBtu
Natural Gas	04/2009 to 05/2011	23,000	$ 5.14
Natural Gas	04/2009 to 09/2012	67,000	$ 4.56

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Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our 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, 2009. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of March 31, 2009 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, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings

Whiting is subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management’s opinion that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 1A. Risk Factors

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2008. No material change to such risk factors has occurred during the three months ended March 31, 2009.

Item 6. Exhibits

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

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on this 30th day of April, 2009.

WHITING PETROLEUM CORPORATION

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

By /s/ Michael J. Stevens
Michael J. Stevens
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)	Fourth Amended and Restated Credit Agreement, dated as of April 28, 2009, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and the various other agents party thereto [Incorporated by reference to Exhibit 4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated April 28, 2009 (File No. 001-31899)].
(31.1)	Certification by the Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.