WHITING PETROLEUM CORP
Form 10-Q
October 29, 2010

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 September 30, 2010

or

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

For the transition period from _______________ to _______________

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

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

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

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

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

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

Large accelerated 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 October 15, 2010: 58,548,894 shares.

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GLOSSARY OF CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms “we,” “us,” “our” or “ours” when used in this report refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this report:

“Bbl” - One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil and other liquid hydrocarbons.

“Bcf” - One billion cubic feet of natural gas.

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

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

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

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

“MBOE/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.

“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, except share and per share data)

	September 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,211	$ 11,960
Accounts receivable trade, net	182,355	152,082
Prepaid expenses and other	14,535	11,983
Total current assets	200,101	176,025
Property and equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	5,392,276	4,870,688
Unproved properties	177,638	100,706
Other property and equipment	89,695	100,833
Total property and equipment	5,659,609	5,072,227
Less accumulated depreciation, depletion and amortization	(1,546,476)	(1,274,121)
Total property and equipment, net	4,113,133	3,798,106
Debt issuance costs	22,935	24,672
Other long-term assets	30,361	30,739
TOTAL ASSETS	$ 4,366,530	$ 4,029,542
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable trade	$ 55,121	$ 14,023
Accrued capital expenditures	73,682	29,998
Accrued liabilities and other	113,452	110,320
Revenues and royalties payable	75,548	46,327
Taxes payable	28,403	21,188
Derivative liabilities	33,432	49,551
Deferred income taxes	4,500	11,325
Total current liabilities	384,138	282,732
Long-term debt	700,000	779,585
Deferred income taxes	500,095	341,037
Derivative liabilities	91,250	137,621
Production Participation Plan liability	78,983	69,433
Asset retirement obligations	73,922	66,846
Deferred gain on sale	47,477	58,462
Other long-term liabilities	25,314	23,741
Total liabilities	1,901,179	1,759,457
Commitments and contingencies		
Stockholders' equity:		

Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 172,500 shares issued and outstanding as of September 30, 2010 and 3,450,000 shares issued and outstanding as of December 31, 2009, aggregate liquidation preference of $17,250,000		-		3
Common stock, $0.001 par value, 175,000,000 shares authorized; 58,986,415 issued and 58,548,894 outstanding as of September 30, 2010, 51,363,638 issued and 50,845,374 outstanding as of December 31, 2009		59		51
Additional paid-in capital		1,547,536		1,546,635
Accumulated other comprehensive income		8,014		20,413
Retained earnings		909,742		702,983
Total stockholders' equity		2,465,351		2,270,085
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$	4,366,530	$	4,029,542

See notes to consolidated financial statements.

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

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 365,239	$ 256,074	$ 1,068,961	$ 616,552
Gain on hedging activities	4,383	7,774	19,641	28,072
Amortization of deferred gain on sale	3,854	4,222	11,613	12,595
Gain on sale of properties	-	1,101	1,918	5,709
Interest income and other	258	156	498	396
Total revenues and other income	373,734	269,327	1,102,631	663,324
COSTS AND EXPENSES:				
Lease operating	69,001	58,807	197,586	177,343
Production taxes	26,193	18,792	77,341	43,225
Depreciation, depletion and amortization	97,704	101,273	289,836	301,622
Exploration and impairment	10,500	12,422	37,915	39,528
General and administrative	19,480	11,314	48,516	30,576
Interest expense	14,579	15,647	45,903	49,020
Loss on early extinguishment of debt	6,235	-	6,235	-
Change in Production Participation Plan liability	3,858	(678)	9,550	3,002
Commodity derivative (gain) loss, net	31,765	(10,391)	(46,654)	171,906
Total costs and expenses	279,315	207,186	666,228	816,222
INCOME (LOSS) BEFORE INCOME TAXES	94,419	62,141	436,403	(152,898)
INCOME TAX EXPENSE (BENEFIT):				
Current	(170)	(507)	6,468	(1,046)
Deferred	36,057	26,793	159,475	(50,785)
Total income tax expense (benefit)	35,887	26,286	165,943	(51,831)
NET INCOME (LOSS)	58,532	35,855	270,460	(101,067)
Preferred stock dividends	(52,920)	(4,911)	(63,701)	(4,911)
NET INCOME (LOSS) AVAILABLE TO COMMON	$ 5,612	$ 30,944	$ 206,759	$ (105,978)

SHAREHOLDERS									
EARNINGS (LOSS) PER COMMON SHARE:									
Basic	$	0.12	$	0.59	$	4.04	$	(2.15	)
Diluted	$	0.12	$	0.59	$	4.00	$	(2.15	)
WEIGHTED AVERAGE SHARES OUTSTANDING:									
Basic		52,148		50,845		51,356		49,774	
Diluted		52,453		51,174		52,096		49,774	

See notes to consolidated financial statements.

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

	Nine Months Ended September 30, 2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 270,460	$ (101,067)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	289,836	301,622
Deferred income tax expense (benefit)	159,475	(50,785)
Amortization of debt issuance costs and debt discount	8,525	8,143
Stock-based compensation	6,585	4,047
Amortization of deferred gain on sale	(11,613)	(12,595)
Gain on sale of properties	(1,918)	(5,709)
Undeveloped leasehold and oil and gas property impairments	12,054	14,743
Exploratory dry hole costs	2,796	2,344
Loss on early extinguishment of debt	6,235	-
Change in Production Participation Plan liability	9,550	3,002
Unrealized (gain) loss on derivative contracts	(82,213)	145,650
Other non-current	(4,495)	646
Changes in current assets and liabilities:		
Accounts receivable trade	(30,273)	(2,317)
Prepaid expenses and other	(637)	30,062
Accounts payable trade and accrued liabilities	49,464	(49,380)
Revenues and royalties payable	29,221	884
Taxes payable	7,215	1,530
Net cash provided by operating activities	720,267	290,820
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(102,256)	(31,475)
Drilling and development capital expenditures	(473,697)	(403,571)
Proceeds from sale of oil and gas properties	7,875	80,308
Net cash used in investing activities	(568,078)	(354,738)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of 6.5% Senior Subordinated Notes due 2018	350,000	-
Redemption of 7.25% Senior Subordinated Notes due 2012	(150,000)	-
Redemption of 7.25% Senior Subordinated Notes due 2013	(223,988)	-
Issuance of 6.25% convertible perpetual preferred stock	-	334,112
Issuance of common stock	-	234,753
Premium on induced conversion of 6.25% convertible perpetual preferred stock	(47,529)	-
Preferred stock dividends paid	(16,172)	(4,911)
Long-term borrowings under credit agreement	850,000	310,000
Repayments of long-term borrowings under credit agreement	(910,000)	(780,000)
Debt issuance costs	(7,570)	(23,141)
Restricted stock used for tax withholdings	(5,679)	(659)

Net cash (used in) provided by financing activities		(160,938)		70,154
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		(8,749)		6,236
CASH AND CASH EQUIVALENTS:				
Beginning of period		11,960		9,624
End of period	$	3,211	$	15,860
NONCASH INVESTING ACTIVITIES:				
Accrued capital expenditures during the period	$	73,682	$	23,372
NONCASH FINANCING ACTIVITIES:				
Issuance of common stock related to the induced conversion of preferred stock	$	317,406	$	-
Preferred stock cancelled in connection with its induced conversion	$	(317,406)	$	-

See notes to consolidated financial statements.

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

	Preferred Stock Shares	Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity	Comprehensive Income (Loss)
BALANCES-January 1, 2009	-	$-	42,582	$43	$971,310	$17,271	$820,167	$1,808,791	
Net loss	-	-	-	-	-	-	(101,067)	(101,067)	$(101,067)
Change in derivative fair values, net of taxes of $7,799	-	-	-	-	-	13,348	-	13,348	13,348
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 $8,355	-	-	-	-	-	14,300	-	14,300	14,300
OCI amortization on de-designated hedges, net of taxes of $5,390	-	-	-	-	-	(9,232)	-	(9,232)	(9,232)
Total comprehensive income									$(91,168)
Issuance of 6.25% convertible perpetual preferred stock	3,450	3	-	-	334,109	-	-	334,112	
Issuance of stock, secondary offering	-	-	8,450	8	234,745	-	-	234,753	
Restricted stock issued			364	-	-	-	-	-	
Restricted stock forfeited	-	-	(5)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(27)	-	(659)	-	-	(659)	
Tax effect from restricted stock vesting	-	-	-	-	(515)	-	-	(515)	
Stock-based compensation	-	-	-	-	4,047	-	-	4,047	
Preferred dividends paid	-	-	-	-	-	-	(4,911)	(4,911)	
BALANCES-September 30, 2009	3,450	$3	51,364	$51	$1,543,037	$27,170	$714,189	$2,284,450	
BALANCES-January 1, 2010	3,450	$3	51,364	$51	$1,546,635	$20,413	$702,983	$2,270,085	
Net income	-	-	-	-	-	-	270,460	270,460	$270,460

OCI amortization on de-designated hedges, net of taxes of $7,242	-	-	-	-	-	(12,399)	-	(12,399)	(12,399)
Total comprehensive income									$258,061
Induced conversion of convertible perpetual preferred stock	(3,277)	(3)	7,549	8	(5)	-	(47,529)	(47,529)	
Restricted stock issued	-	-	162	-	-	-	-	-	
Restricted stock forfeited	-	-	(11)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(78)	-	(5,679)	-	-	(5,679)	
Stock-based compensation	-	-	-	-	6,585	-	-	6,585	
Preferred dividends paid	-	-	-	-	-	-	(16,172)	(16,172)	
BALANCES-September 30, 2010	173	$-	58,986	$59	$1,547,536	$8,014	$909,742	$2,465,351	

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 GAAP for interim financial reporting. In the opinion of management, the accompanying financial statements include all adjustments (consisting of normal recurring accruals and adjustments) necessary to present fairly, in all material respects, the Company's interim results. However, operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year. Whiting's 2009 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. Except as disclosed herein, there have been no material changes to the information disclosed in the notes to the consolidated financial statements included in Whiting's 2009 Annual Report on Form 10-K.

Earnings Per Share—Basic earnings per common share is calculated by dividing net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted earnings per common share is calculated by dividing adjusted net income available to common shareholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method, as well as convertible perpetual preferred stock using the if-converted method. In the computation of diluted earnings per share, excess tax benefits that would be created upon the assumed vesting of unvested restricted shares or the assumed exercise of stock options (i.e. hypothetical excess tax benefits) are included in the assumed proceeds component of the treasury share method to the extent that such excess tax benefits are more likely than not to be realized. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

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

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2. ACQUISITIONS AND DIVESTITURES

2010 Activity

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

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

There were no significant divestitures during the first nine months of 2010.

2009 Acquisitions

During 2009, Whiting acquired additional royalty and overriding royalty interests in the North Ward Estes field and various other fields in the Permian Basin in two separate transactions with private owners. Also included in these transactions were contractual rights, including an option to participate for an aggregate 10% working interest and right to back in after payout for an additional aggregate 15% working interest in the development of deeper pay zones on acreage under and adjoining the North Ward Estes field.

Whiting completed the first acquisition of additional royalty and overriding royalty interests in November 2009, with a purchase price of $38.7 million and an effective date of October 1, 2009. The Company completed the second acquisition of additional royalty and overriding royalty interests in December 2009, with a purchase price of $27.4 million and an effective date of November 1, 2009. Reserves attributable to royalty and overriding royalty interests are not burdened by operating expenses or any additional capital costs, including CO2 costs, which are paid by the working interest owners. These two acquisitions were funded primarily from net cash provided by operating activities. Substantially all of the purchase price was allocated to the properties acquired.

2009 Participation Agreement

In June 2009, Whiting entered into a participation agreement with a privately held independent oil company covering twenty-five 1,280-acre units and one 640-acre unit located primarily in the western portion of the Sanish field in Mountrail County, North Dakota. Under the terms of the agreement, the private company agreed to pay 65% of Whiting’s net drilling and well completion costs to receive 50% of Whiting’s working interest and net revenue interest in the first and second wells planned for each of the units. Pursuant to the agreement, Whiting will remain the operator for each unit.

At the closing of the agreement, the private company paid Whiting $107.3 million, representing $6.4 million for acreage costs, $65.8 million for 65% of Whiting’s cost in 18 wells drilled or drilling and $35.1 million for a 50% interest in Whiting’s Robinson Lake gas plant and oil and gas gathering system. Whiting used these proceeds to repay a portion of the debt outstanding under its credit agreement.

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3. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2010 and December 31, 2009 (in thousands):

	September 30, 2010	December 31, 2009
Credit Agreement	$100,000	$160,000
6.5% Senior Subordinated Notes due 2018	350,000	-
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,147	-	218,853
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $268	-	150,732
Total debt	$700,000	$779,585

Credit Agreement—As of September 30, 2010, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), the Company's wholly-owned subsidiary, had a credit agreement with a syndicate of banks, and this credit facility had a borrowing base of $1.1 billion with $999.6 million of available borrowing capacity, which was net of $100.0 million in borrowings and $0.4 million in letters of credit outstanding. The credit agreement provided for interest only payments until April 2012, when the agreement expired and all outstanding borrowings were due. In October 2010, Whiting Oil and Gas entered into a Fifth Amended and Restated Credit Agreement with its bank syndicate, which replaced the existing credit agreement. This amended credit agreement extended the principal repayment date from April 2012 to October 2015. Further information on the terms of the new credit agreement is discussed in the note on Subsequent Events. The following is a description of the credit agreement in place as of September 30, 2010.

The borrowing base under the credit agreement was determined at the discretion of the lenders, based on the collateral value of the proved reserves that had been mortgaged to the lenders, and was 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 have reduced the amount of the borrowing base. Whiting Oil and Gas could have, throughout the term of the credit agreement, borrowed, repaid and reborrowed up to the borrowing base in effect at any given time. A portion of the revolving credit agreement in an aggregate amount not to exceed $50.0 million could have been used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of September 30, 2010, $49.6 million was available for additional letters of credit under the agreement.

Interest accrued at the Company's option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. The Company also incurred commitment fees of 0.50% on the unused portion of the lesser of the aggregate commitments of the lenders or the borrowing base, which were included as a component of interest expense. At September 30, 2010, the weighted average interest rate on the outstanding principal balance borrowed under the credit agreement was 2.3%.

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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%

The credit agreement contained restrictive covenants that may have limited 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 required the Company, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.5 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 and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0, and (iii) to not exceed a senior secured debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 2.5 to 1.0. Except for limited exceptions, which included the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement restricted its ability to make any dividend payments or distributions on its common stock or principal payments on its senior notes. The Company was in compliance with its covenants under the credit agreement as of September 30, 2010.

The obligations of Whiting Oil and Gas under the credit agreement were 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 had guaranteed the obligations of Whiting Oil and Gas under the credit agreement and pledged the stock of Whiting Oil and Gas as security for its guarantee.

Senior Subordinated Notes—In October 2005, the Company issued at par $250.0 million of 7% Senior Subordinated Notes due February 2014. The estimated fair value of these notes was $263.8 million as of September 30, 2010, based on quoted market prices for these same debt securities.

Redemption of 7.25% Senior Subordinated Notes Due 2012 and 2013—In September 2010, the Company paid $383.5 million to redeem all of its $150.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2012 and all of its $220.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2013, which consisted of a redemption price of 100.00% for the 2012 notes and 101.8125% for the 2013 notes and included the payment of accrued and unpaid interest on such notes. The Company financed the redemption of the 2012 and 2013 notes with borrowings under its credit agreement. As a result of the redemption, Whiting recognized a $6.2 million loss on early extinguishment of debt, which consisted of a cash charge of $4.0 million related to the redemption premium on the 2013 notes and a non-cash charge of $2.2 million related to the acceleration of debt discounts and unamortized debt issuance costs.

Issuance of 6.5% Senior Subordinated Notes Due 2018—In September 2010, the Company issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. The Company used the net proceeds from this issuance to repay a portion of the debt, which was borrowed to redeem its 2012 and 2013 notes, outstanding under its credit agreement. The estimated fair value of these notes was $357.4 million as of September 30, 2010, based on quoted market prices for these same debt securities.

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

4. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration (including removal of certain onshore and offshore facilities in California) in accordance with applicable local, state and federal laws. The Company follows FASB ASC Topic 410, Asset Retirement and Environmental Obligations, to determine its asset retirement obligation amounts by calculating the present value of the estimated future cash outflows associated with its plug and abandonment obligations. The current portions at September 30, 2010 and December 31, 2009 were $5.7 million and $10.3 million, respectively, and are included in accrued liabilities and other. The following table provides a reconciliation of the Company's asset retirement obligations for the nine months ended September 30, 2010 (in thousands):

Asset retirement obligation, January 1, 2010	$77,186
Additional liability incurred	2,277
Revisions in estimated cash flows	1,331
Accretion expense	5,421
Obligations on sold properties	(2,942)
Liabilities settled	(3,611)
Asset retirement obligation, September 30, 2010	$79,662

5. DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to certain risks relating to its ongoing business operations, and Whiting uses derivative instruments to manage its commodity price risk. Whiting follows FASB ASC Topic 815, Derivatives and Hedging, to account for its derivative financial instruments.

Commodity derivative contracts—Historically, prices received for crude oil and natural gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Whiting enters into derivative contracts, primarily costless collars, to achieve a more predictable cash flow by reducing its exposure to commodity price volatility. Commodity derivative contracts are also used to ensure adequate cash flow to fund the Company's capital programs and to manage returns on acquisitions and drilling programs. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The Company does not enter into derivative contracts for speculative or trading purposes.

Whiting derivatives. The table below details the Company's costless collar derivatives, including its proportionate share of Whiting USA Trust I (the "Trust") derivatives, entered into to hedge forecasted crude oil and natural gas production revenues, as of October 15, 2010.

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	Whiting Petroleum Corporation			
			Weighted Average	
	Contracted Volumes		NYMEX Price Collar Ranges	
	Crude Oil	Natural Gas	Crude Oil	Natural Gas
Period	(Bbl)	(Mcf)	(per Bbl)	(per Mcf)
Oct – Dec 2010	2,415,437	118,336	$64.43 - $91.26	$7.00 - $14.20
Jan – Dec 2011	9,655,039	436,510	$60.40 - $96.90	$6.50 - $14.62
Jan – Dec 2012	4,065,091	384,002	$50.08 - $95.28	$6.50 - $14.27
Jan – Nov 2013	3,090,000	-	$47.64 - $89.90	n/a
Total	19,225,567	938,848		

Derivatives conveyed to Whiting USA Trust I. In connection with the Company's conveyance in April 2008 of a term net profits interest to the Trust and related sale of 11,677,500 Trust units to the public, the right to any future hedge payments made or received by Whiting on certain of its derivative contracts have been conveyed to the Trust, and therefore such payments will be included in the Trust's calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties. Whiting's retention of 10% of these net proceeds, combined with its ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, and Whiting retaining 24.2%, of the future economic results of commodity derivative contracts conveyed to the Trust. The relative ownership of the future economic results of such commodity derivatives is reflected in the tables below. No additional hedges are allowed to be placed on Trust assets.

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

	Whiting Petroleum Corporation			
			Weighted Average	
	Contracted Volumes		NYMEX Price Collar Ranges	
	Crude Oil	Natural Gas	Crude Oil	Natural Gas
Period	(Bbl)	(Mcf)	(per Bbl)	(per Mcf)
Oct – Dec 2010	30,437	118,336	$76.00 - $135.11	$7.00 - $14.20
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	250,567	938,848		

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

	Third-party Public Holders of Trust Units			
			Weighted Average	
	Contracted Volumes		NYMEX Price Collar Ranges	
	Crude Oil	Natural Gas	Crude Oil	Natural Gas
Period	(Bbl)	(Mcf)	(per Bbl)	(per Mcf)

Oct – Dec 2010	95,335	370,655	$76.00 - $135.11	$7.00 - $14.20
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	784,835	2,940,689		

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Discontinuance of cash flow hedge accounting—Prior to April 1, 2009, the Company designated a portion of its commodity derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to other comprehensive income, 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 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 elected to discontinue hedge accounting prospectively. As a result, subsequent to March 31, 2009 the Company recognizes all 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 net of tax) of unrealized gains, representing the mark-to-market value of the Company's open commodity contracts designated as cash flow hedges as of that 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 reclassified into earnings as the original hedged transactions affect income. During the three and nine months ended September 30, 2010, $4.4 million ($2.8 million net of tax) and $19.6 million ($12.4 million net of tax), respectively, of derivative gains relating to de-designated commodity hedges were reclassified from accumulated other comprehensive income into earnings.

As of September 30, 2010, accumulated other comprehensive income amounted to $12.7 million ($8.0 million net of tax), which consisted entirely of unrealized deferred gains on commodity derivative contracts that had been previously designated as cash flow hedges. During the next twelve months, the Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax gains of $6.9 million related to de-designated commodity hedges.

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

		Fair Value	
Not Designated as ASC 815 Hedges	Balance Sheet Classification	September 30, 2010	December 31, 2009
Derivative assets:			
Commodity contracts	Prepaid expenses and other	$ 6,638	$ 4,723
Commodity contracts	Other long-term assets	6,639	8,473
Total derivative assets		$ 13,277	$ 13,196
Derivative liabilities:			
Commodity contracts	Current derivative liabilities	$ 33,432	$ 49,551
Commodity contracts	Non-current derivative liabilities	91,250	137,621
Total derivative liabilities		$ 124,682	$ 187,172

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The following tables summarize the effects of commodity derivatives instruments on the consolidated statements of income for the three and nine months ended September 30, 2010 and 2009 (in thousands).

ASC 815 Cash Flow Hedging Relationships	Location of Gain (Loss) Not Recognized in Income	Gain Recognized in OCI (Effective Portion) Nine Months Ended September 30, 2010	2009
Commodity contracts	Other comprehensive income	$ -	$ 21,147
		Three Months Ended September 30, 2010	2009
Commodity contracts	Other comprehensive income	$ -	$ -

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Gain (Loss) Reclassified from OCI into Income (Effective Portion) Nine Months Ended September 30, 2010	2009
Commodity contracts	Gain on hedging activities	$ 19,641	$ 28,072
		Three Months Ended September 30, 2010	2009
Commodity contracts	Gain on hedging activities	$ 4,383	$ 7,774

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Loss Recognized in Income (Ineffective Portion) Nine Months Ended September 30, 2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$ -	$ 22,655
		Three Months Ended September 30, 2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$ -	$ -

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Nine Months Ended September 30, 2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$ (46,654)	$ 149,251
		Three Months Ended September 30, 2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$ 31,765	$ (10,391)

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 its derivative counterparties in order to secure contract performance obligations.

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6. FAIR VALUE MEASURMENTS

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

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

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

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

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

The following table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value September 30, 2010
Financial Assets				
Commodity derivatives - current	$-	$6,638	$-	$6,638
Commodity derivatives - non-current	-	6,639	-	6,639
Total financial assets	$-	$13,277	$-	$13,277
Financial Liabilities				
Commodity derivatives - current	$-	$33,432	$-	$33,432
Commodity derivatives - non-current	-	91,250	-	91,250
Total financial liabilities	$-	$124,682	$-	$124,682

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

Commodity Derivative Instruments. Commodity derivative instruments consist primarily of costless collars for crude oil and natural gas. The Company's costless collars are valued using industry-standard models, which are based on a market approach. These models consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy. The discount rates used in the fair values of these instruments include a measure of either the Company's or the counterparty's nonperformance risk, as appropriate. The Company utilizes counterparties' valuations to assess the reasonableness of its own valuations.

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Non-Recurring Fair Value Measurements. The Company applies the provisions of the fair value measurement standard to its non-recurring, non-financial measurements including business combinations, proved oil and gas property impairments and asset retirement obligations. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The following table presents information about the Company's non-financial assets and liabilities measured at fair value on a non-recurring basis as of September 30, 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Net Carrying Value as of September 30, 2010	Fair Value Measurements Using			Pre-tax (Gain) Loss Nine Months Ended September 30, 2010
		Level 1	Level 2	Level 3	
Asset retirement obligations	$2,298	$-	$-	$2,277	$-
Total non-recurring assets at fair value	$2,298	$-	$-	$2,277	$-

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

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

7. DEFERRED COMPENSATION

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

Payments of 100% of the year's Plan interests to employees and the vested percentages of former employees in the year's Plan interests are made annually in cash after year-end. Accrued compensation expense under the Plan for the nine months ended September 30, 2010 and 2009 amounted to $21.2 million and $10.4 million, respectively, charged to general and administrative expense and $2.9 million and $1.5 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 September 30, 2010, the Company used three-year average historical NYMEX prices of $79.48 for crude oil and $5.81 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control of the Company (as defined in the Plan), all employees fully vest, and the Company would distribute to each Plan participant an amount based upon the valuation method set forth in the Plan in a lump sum payment twelve months after the date of termination or within one month after a change in control event. Based on current strip prices at September 30, 2010, 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 $146.3 million. This amount includes $15.3 million attributable to proved undeveloped oil and gas properties and $24.1 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2011. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control. However, the Company has no intention to terminate the Plan.

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

Long-term Production Participation Plan liability, January 1, 2010	$69,433
Change in liability for accretion, vesting, change in estimates and new Plan year activity	33,601
Cash payments accrued as compensation expense and reflected as a current payable	(24,051)
Long-term Production Participation Plan liability, September 30, 2010	$78,983

8. STOCKHOLDERS' EQUITY

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

Common Stock Offering. In February 2009, the Company completed a public offering of its common stock, selling 8,450,000 shares of common stock at a price of $29.00 per share and providing net proceeds of $234.8 million after underwriters' fees and offering expenses. The Company used the net proceeds to repay a portion of the debt outstanding under its credit agreement.

6.25% Convertible Perpetual Preferred Stock—In June 2009, the Company completed a public offering of 6.25% convertible perpetual preferred stock ("preferred stock"), selling 3,450,000 shares at a price of $100.00 per share and providing net proceeds of $334.1 million after underwriters' fees and offering expenses. The Company used the net proceeds to repay a portion of the debt outstanding under its credit agreement.

Each holder of the preferred stock is entitled to an annual dividend of $6.25 per share to be paid quarterly in cash, common stock or a combination thereof on March 15, June 15, September 15 and December 15, when and if such dividend has been declared by Whiting's board of directors. Each share of preferred stock has a liquidation preference of $100.00 per share plus accumulated and unpaid dividends and is convertible, at a holder's option, into shares of Whiting's common stock based on an initial conversion price of $43.4163, subject to adjustment upon the occurrence of certain events. The preferred stock is not redeemable by the Company. At any time on or after June 15, 2013, the Company may cause all outstanding shares of this preferred stock to be converted into shares of common stock if the closing price of our common stock equals or exceeds 120% of the then-prevailing conversion price for at least 20 trading days in a period of 30 consecutive trading days. The holders of preferred stock have no voting rights unless dividends payable on the preferred stock are in arrears for six or more quarterly periods.

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Induced Conversion of 6.25% Convertible Perpetual Preferred Stock. In August 2010, Whiting commenced an offer to exchange up to 3,277,500, or 95%, of its preferred stock for the following consideration per share of preferred stock: 2.3033 shares of its common stock and a cash premium of $14.50. The exchange offer expired in September 2010 and resulted in the Company accepting 3,277,500 shares of preferred stock in exchange for the issuance of 7,549,010 shares of common stock and a cash premium payment of $47.5 million. Following the exchange offer, the 3,277,500 shares of preferred stock accepted in the exchange were cancelled, and a total of 172,500 shares of preferred stock remained outstanding.

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 nine months ended September 30, 2010 and 2009 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% to pre-tax income primarily because of state income taxes and estimated permanent differences.

The computation of the annual estimated effective tax rate at each interim period requires certain estimates and significant judgment including, but not limited to, the expected operating income for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent and temporary differences, and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained, additional information becomes known or as the tax environment changes.

10. EARNINGS PER SHARE

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

	Three Months Ended September 30,	
	2010	2009
Basic Earnings Per Share		
Numerator:		
Net income	$58,532	$35,855
Preferred stock dividends (1)	(52,077)	(5,797)
Net income available to common shareholders, basic	$6,455	$30,058
Denominator:		
Weighted average shares outstanding, basic	52,148	50,845

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	Three Months Ended September 30, 2010	2009
Diluted Earnings Per Share		
Numerator:		
Net income available to common shareholders, basic	$6,455	$30,058
Preferred stock dividends	-	-
Adjusted net income available to common shareholders, diluted	$6,455	$30,058
Denominator:		
Weighted average shares outstanding, basic	52,148	50,845
Restricted stock and stock options	305	329
Convertible perpetual preferred stock	-	-
Weighted average shares outstanding, diluted	52,453	51,174
Earnings per common share, basic	$0.12	$0.59
Earnings per common share, diluted	$0.12	$0.59

(1) For the three months ended September 30, 2010, amount includes a decrease of $0.8 million in preferred stock dividends for preferred stock dividends accumulated. For the three months ended September 30, 2009, amount includes an increase of $0.9 million in preferred stock dividends for preferred stock dividends accumulated.

For the three months ended September 30, 2010, the diluted earnings per share calculation excludes the effect of 6,797,564 incremental common shares (which were issuable upon the conversion of perpetual preferred stock as of a July 1, 2010 assumed conversion date) because their effect was anti-dilutive. For the three months ended September 30, 2009, the diluted earnings per share calculation excludes the effect of 7,946,324 common shares, which were issuable upon the assumed conversion of perpetual preferred stock, because their effect was anti-dilutive.

	Nine Months Ended September 30, 2010	2009
Basic Earnings Per Share		
Numerator:		
Net income (loss)	$270,460	$(101,067)
Preferred stock dividends (1)	(62,859)	(5,797)
Net income (loss) available to common shareholders, basic	$207,601	$(106,864)
Denominator:		
Weighted average shares outstanding, basic	51,356	49,774

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	Nine Months Ended September 30, 2010	2009
Diluted Earnings Per Share		
Numerator:		
Net income (loss) available to common shareholders, basic	$207,601	$(106,864)
Preferred stock dividends	809	-
Adjusted net income (loss) available to common shareholders, diluted	$208,410	$(106,864)
Denominator:		
Weighted average shares outstanding, basic	51,356	49,774
Restricted stock and stock options	343	-
Convertible perpetual preferred stock	397	-
Weighted average shares outstanding, diluted	52,096	49,774
Earnings (loss) per common share, basic	$4.04	$(2.15)
Earnings (loss) per common share, diluted	$4.00	$(2.15)

(1) For the nine months ended September 30, 2010, amount includes a decrease of $0.8 million in preferred stock dividends for preferred stock dividends accumulated. For the nine months ended September 30, 2009, amount includes an increase of $0.9 million in preferred stock dividends for preferred stock dividends accumulated.

For the nine months ended September 30, 2010, the diluted earnings per share calculation excludes the effect of 7,161,881 incremental common shares (which were issuable upon the conversion of perpetual preferred stock as of a January 1, 2010 assumed conversion date) because their effect was anti-dilutive. For the nine months ended September 30, 2009, the Company had a net loss. Therefore, the diluted earnings per share calculation for that period excludes the effect of 292,675 shares of restricted stock and stock options, as well as 2,881,634 weighted average shares of convertible preferred stock outstanding because their effect was anti-dilutive.

11. ADOPTED AND RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, Improving Disclosures about Fair Value Measurements ("ASU 2010-06"), which provides amendments to FASB ASC Topic 820, Fair Value Measurements and Disclosures. The objective of ASU 2010-06 is to provide more robust disclosures about (i) the different classes of assets and liabilities measured at fair value, (ii) the valuation techniques and inputs used, (iii) the activity in Level 3 fair value measurements, and (iv) significant transfers between Levels 1, 2 and 3. ASU 2010-06 became effective for fiscal years and interim periods beginning after December 15, 2009. The Company adopted ASU 2010-06 effective January 1, 2010, which did not have an impact on its consolidated financial statements, other than additional disclosures.

12. SUBSEQUENT EVENT

In October 2010, Whiting Oil and Gas entered into a Fifth Amended and Restated Credit Agreement with its bank syndicate, which replaced the existing credit facility. This amended credit agreement maintained the borrowing base of $1.1 billion and extended the principal repayment date to October 2015. 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.

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The amended credit agreement provides for interest only payments until October 2015, 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	0.75%	1.75%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.00%	2.00%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.25%	2.25%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.50%	2.50%
Greater than or equal to 0.90 to 1.0	1.75%	2.75%

Under the amended 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.

The amended 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 the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for quarters ending March 31, 2013 and thereafter and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. Except for limited exceptions, which include the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement restricts the Company's ability to make any dividend payments or distributions on its common stock.

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

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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 and Whiting Programs, Inc. When the context requires, we refer to these entities separately. This document contains forward-looking statements, which give our current expectations or forecasts of future events. Please refer to “Forward-Looking Statements” at the end of this Item for an explanation of these types of statements.

Overview

We are an independent oil and gas company engaged in acquisition, development, exploitation, production and exploration activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan regions of the United States. Prior to 2006, we generally emphasized the acquisition of properties that increased our production levels and provided upside potential through further development. Since 2006, we have focused primarily on organic drilling activity and on the development of previously acquired properties, specifically on projects that we believe provide the opportunity for repeatable successes and production growth. We believe the combination of acquisitions, subsequent development and organic drilling provides us a broad set of growth alternatives and allows us to direct our capital resources to what we believe to be the most advantageous investments.

As demonstrated by our recent capital expenditure programs, we are increasingly focused on a balanced exploration and development program, while continuing to selectively pursue acquisitions that complement our existing core properties. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. Our growth plan is centered on the following activities:

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

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that established a presence in a new area of interest or that have complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. In addition, our willingness to acquire non-operated properties in new geographic regions provides us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis. We sell properties when we believe that the sales price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

Although oil prices fell significantly after reaching a high in the third quarter of 2008 with a daily average NYMEX of $118.13 per Bbl, they have experienced a rebound in the second half of 2009 and first nine months of 2010. For example, the daily average NYMEX oil price was $43.21, $59.62, $68.29 and $76.17 per Bbl for the first, second, third and fourth quarters of 2009, respectively, and $78.79, $77.99 and $76.21 per Bbl for the first, second and third quarters of 2010, respectively. Additionally, natural gas prices have fallen significantly since their third quarter 2008 daily average NYMEX of $10.27 per Mcf and remained low throughout 2009, but have slightly increased during the first nine months of 2010. For example, daily average NYMEX natural gas prices declined to $3.99 per Mcf for 2009, but rose to $4.59 per Mcf for the first nine months of 2010. Lower oil and natural gas prices may not only decrease our revenues, but may also reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve bookings. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. Lower oil and gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders. Alternatively, higher oil and natural gas prices may result in significant non-cash mark-to-market losses being recognized on our commodity derivatives, which may in turn cause us to experience net losses.

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2010 Highlights and Future Considerations

Operational Highlights. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations. Net production in the Sanish field increased 113% from 10.5 MBOE/d in the third quarter of 2009 to 22.3 MBOE/d in the third quarter of 2010. Based on results of our microseismic studies and reservoir pressure monitoring in both the Bakken and Three Forks formations, it appears that additional infill drilling is necessary to maximize primary recovery in the Sanish field. As a result, we have increased by 156 the total number of gross operated wells that we expect to drill in the Sanish field to 469 gross wells from 313 gross wells. We have also elected to drill three Three Forks wells per 1,280-acre unit as compared to its previous plan of two Three Forks wells per unit. This decision adds 80 potential gross well locations in the Sanish field. Including non-operated wells, we estimate that 323 gross wells remain to be drilled in the Sanish field as of October 15, 2010, for a total of 534 gross wells.

From January 1 through October 15, 2010, we completed 57 operated wells in the Sanish field, bringing to 121 the total number of operated wells in the field. As of October 15, 2010, 17 operated wells were being completed or awaiting completion and nine operated wells were being drilled in the Sanish field. In 2010, we intend to drill or participate in the drilling of a total of 98 gross (52 net) wells in the Sanish field, of which 88 will target the Bakken formation and ten will target the Three Forks formation.

Net production in the Parshall field decreased 25% from 6.8 MBOE/d in the third quarter of 2009 to 5.1 MBOE/d in the third quarter of 2010. This production decrease was primarily due to normal field production decline and reduced drilling in the area as the operator of the Parshall field has drilled almost all of its Bakken locations and is currently pursuing a moderate pace of development of the Three Forks formation with a one-rig program.

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

Production continued to increase from the Postle field, which is located in Texas County, Oklahoma and produces from the Morrow sandstone. In the third quarter of 2010, the field produced at an average net rate of 9.3 MBOE/d, representing a 7% increase from the 8.7 MBOE/d rate in the third quarter of 2009. We manage our CO2 flood at Postle on a pattern-by-pattern basis in order to optimize utilization of CO2, production and ultimate recovery. A pattern typically consists of a producing well surrounded by four water/CO2 injectors. As a pattern matures, increasing volumes of water are alternated with CO2 injection to control gas break through and sweep efficiency. This process, referred to as “WAG” (Water Alternating Gas), typically results in the highest possible oil recovery; however, the production response can have a cyclical behavior during periods of high water injection. A number of patterns were cycled to water injection during the third quarter of 2010, which caused a normal slowing of oil response. During the same period, a failure of the hot oil system at the gas processing facility resulted in a sudden decrease of CO2 injection. The combined effect of the increased water injection and loss of CO2 injection resulted in the production decrease during the third quarter of 2010 as compared with the same period in 2009.

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The North Ward Estes field is located in Ward and Winkler Counties, Texas and is responding positively to our water and CO2 floods, which we initiated in May 2007. In early March 2009, we expanded the area of our CO2 injection project. Net production from the field increased 17% from 6.4 MBOE/d in the third quarter of 2009 to 7.5 MBOE/d in the third quarter of 2010. In this field, we are developing new and reactivated wells for water and CO2 injection and production purposes. Additionally, we plan to install oil, gas and water processing facilities in eight phases. The first two phases were largely completed by December 2009, and we estimate that Phase III-A will be substantially complete in the fourth quarter of 2010.

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

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

Financing Highlights. In September 2010, we paid $383.5 million to redeem all of our $150.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2012 and all of our $220.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2013, which consisted of a redemption price of 100.00% for the 2012 notes and 101.8125% for the 2013 notes and included the payment of accrued and unpaid interest on such notes. We financed the redemption of the 2012 and 2013 notes with borrowings under our credit agreement. As a result of the redemption, we recognized a $6.2 million loss on early extinguishment of debt, which consisted of a cash charge of $4.0 million related to the redemption premium on the 2013 notes and a non-cash charge of $2.2 million related to the acceleration of debt discounts and unamortized debt issuance costs.

In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. We used the net proceeds from this issuance to repay a portion of the debt, which was borrowed to redeem our 2012 and 2013 notes, outstanding under our credit agreement.

In August 2010, we commenced an offer to exchange up to 3,277,500, or 95%, of our outstanding 6.25% convertible perpetual preferred stock (“preferred stock”) for the following consideration per share of preferred stock: 2.3033 shares of our common stock and a cash premium of $14.50. The exchange offer expired in September 2010 and resulted in 3,277,500 shares of preferred stock being exchanged for the issuance of 7,549,010 shares of our common stock and a cash premium payment of $47.5 million. Following the exchange offer, the 3,277,500 shares of preferred stock accepted in the exchange were cancelled, and a total of 172,500 shares of preferred stock remained outstanding.

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Results of Operations

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Selected Operating Data:	Nine Months Ended September 30, 2010	2009
Net production:		
Oil (MMBbls)	14.0	11.3
Natural gas (Bcf)	20.1	22.6
Total production (MMBOE)	17.3	15.1
Net sales (in millions):		
Oil (1)	$967.7	$539.6
Natural gas (1)	101.3	77.0
Total oil and natural gas sales	$1,069.0	$616.6
Average sales prices:		
Oil (per Bbl)	$69.10	$47.79
Effect of oil hedges on average price (per Bbl)	(1.19)	0.07
Oil net of hedging (per Bbl)	$67.91	$47.86
Average NYMEX price (per Bbl)	$77.65	$57.13
Natural gas (per Mcf)	$5.05	$3.41
Effect of natural gas hedges on average price (per Mcf)	0.03	0.05
Natural gas net of hedging (per Mcf)	$5.08	$3.46
Average NYMEX price (per Mcf)	$4.59	$3.93
Cost and expense (per BOE):		
Lease operating expenses	$11.39	$11.78
Production taxes	$4.46	$2.87
Depreciation, depletion and amortization expense	$16.71	$20.04
General and administrative expenses	$2.80	$2.03

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $452.4 million to $1,069.0 million in the first nine months of 2010 compared to the same period in 2009. Sales are a function of oil and gas volumes sold and average sales prices. Our oil sales volumes increased 24% between periods, while our natural gas sales volumes decreased 11%. 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, partially offset by production decreases due to pipeline maintenance on the Enbridge system. Oil production from the Bakken in the first nine months of 2010 increased 2,225 MBbl compared to the first nine months of 2009, while North Ward Estes oil production increased 410 MBbl and Postle oil production increased 375 MBbl over the same prior year period. The gas volume decrease between periods was primarily the result of normal field production decline, which led to gas production decreases of 1,225 MMcf and 1,185 MMcf at our Boies Ranch and Kawitt areas, respectively, compared to the first nine months of 2009. These production decreases were partially offset by increased gas production of 1,100 MMcf in our North Dakota Bakken area. Also contributing to the increase in oil and natural gas sales revenue in 2010 were increases in average sales prices. Our average price for oil before the effects of hedging increased 45% between periods, and our average price for natural gas before the effects of hedging increased 48%. In addition to higher average NYMEX pricing during the first nine months of 2010 as compared to the same period in 2009, natural gas sales price increases were also due to fixed-price gas contracts entered into at our Flat Rock and Boies Ranch areas that carried a weighted-average price of $5.35 per Mcf for the first nine months of 2010. These contracts were in effect starting in the latter portion of the fourth quarter of 2009.

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Gain on Hedging Activities. Our gain on hedging activities decreased $8.4 million in 2010 as compared to the first nine months of 2009. The components of our gain on hedging activities were as follows (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Gains reclassified from AOCI on de-designated hedges	$19,641	$14,622
Realized cash settlement gains on crude oil derivatives	-	13,450
Total	$19,641	$28,072

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

See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas derivatives as of October 15, 2010.

Lease Operating Expenses. Our lease operating expenses ("LOE") during the first nine months of 2010 were $197.6 million, a $20.2 million increase over the same period in 2009. This higher amount of LOE in 2010 was related to increases of $5.3 million in transportation charges, $4.9 million in ad valorem taxes and $3.8 million in electricity costs between periods, as well as a higher level of workover activity. The increase in transportation charges was primarily due to higher transportation fees on non-operated properties in the Bakken. Workovers amounted to $48.4 million in the first nine months of 2010, as compared to $37.8 million in the first nine months of 2009, and this increase in workover activity primarily related to our two CO_2 projects. Our lease operating expenses on a BOE basis, however, decreased from $11.78 during the first nine months of 2009 to $11.39 during the first nine months of 2010. This decrease of 3% on a BOE basis was primarily the result of the increase in overall production volumes between periods.

Production Taxes. Our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of credits and exemptions allowed in our various taxing jurisdictions. Our production taxes during the first nine months of 2010 were $77.3 million, a $34.1 million increase over the same period in 2009, primarily due to higher oil and natural gas sales between periods. Our company-wide production tax rates for the first nine months of 2010 and 2009 were 7.2% and 7.0%, respectively, of oil and natural gas sales. Our production tax rate for the first nine months of 2010 was greater than the rate for same period in 2009 mainly due to successful wells completed during the fourth quarter of 2009 and the first nine months of 2010 in the North Dakota Bakken area, which has an 11.5% production tax rate.

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Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense decreased $11.8 million in 2010 as compared to the first nine months of 2009. The components of our DD&A expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Depletion	$282,844	$293,869
Depreciation	1,571	2,370
Accretion of asset retirement obligations	5,421	5,383
Total	$289,836	$301,622

DD&A decreased in the first nine months of 2010 primarily due to $11.0 million in lower depletion expense between periods. This net decrease in depletion of $11.0 million was the result of $55.9 million in lower depletion expense due to a decline in our depletion rate between periods, which effect was largely offset by $44.9 million of additional depletion expense due to higher overall production volumes during the first nine months of 2010. On a BOE basis, our DD&A rate of $16.71 for the first nine months of 2010 was 17% lower than the rate of $20.04 for the same period in 2009. The primary factors causing this lower DD&A rate was a net increase in our estimated proved reserves of 35.9 MMBOE as of December 31, 2009, as well as proved developed and total proved reserves added during the first nine months of 2010. This factor was partially offset by (i) $607.9 million in drilling and development expenditures incurred during the past twelve months and (ii) 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 decreased $1.6 million in the first nine months of 2010, as compared to the first nine months of 2009. The components of our exploration and impairment costs were as follows (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Exploration	$25,861	$24,785
Impairment	12,054	14,743
Total	$37,915	$39,528

Exploration costs increased $1.1 million during the first nine months of 2010 as compared to the same period in 2009 primarily due to an increase in geological and geophysical ("G&G") activity, increased accrued Production Participation Plan ("the Plan") payments for G&G personnel and higher exploratory dry hole costs, partially offset by reduced rig termination fees. G&G costs amounted to $12.0 million during the first nine months of 2010 as compared to $6.2 million during the same period in 2009. Accrued Plan distributions for exploration personnel were $1.3 million higher during the first nine months of 2010 as compared to the same prior year period primarily due to a higher level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula) resulting from higher overall production and higher oil and natural gas prices during the first nine months of 2010 as compared to the same period in 2009. These increases were partially offset by reduced rig termination fees recognized in the first nine months of 2010. No rig termination fees were paid during the first nine months of 2010, while rig termination fees totaled $6.5 million during the first nine months of 2009.

The impairment charges in the first nine months of 2010 and 2009 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. The decrease of $2.7 million in impairment expense between periods, however, was mainly due to $3.1 million in non-cash impairment charges in the first nine months of 2009 for the partial write-down of certain proved properties whose net book values exceeded their undiscounted future cash flows. There were no proved property impairment charges during the first nine months of 2010.

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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):

	Nine Months Ended September 30,	
	2010	2009
General and administrative expenses	$88,372	$68,100
Reimbursements and allocations	(39,856)	(37,524)
General and administrative expense, net	$48,516	$30,576

General and administrative expenses before reimbursements and allocations increased $20.3 million during the first nine months of 2010 as compared to the same period in 2009 primarily due to an increase in accrued Plan distributions, higher employee compensation and 2010 offering costs related to the 6.25% convertible perpetual preferred stock exchange offer. The largest component of the increase related to $12.2 million in higher accrued distributions under the Plan between periods. Employee compensation increased $7.6 million in the first nine months of 2010 due to higher stock compensation between periods, personnel hired during the past twelve months and general pay increases. In addition, we incurred $2.2 million of offering costs in 2010 related to the preferred stock exchange offer completed in September. The increase in reimbursements and allocations in the first nine months of 2010 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales remained constant at 5% for the first nine months of 2010 and 2009.

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

	Nine Months Ended September 30,	
	2010	2009
Senior Subordinated Notes	$31,972	$32,826
Credit agreement	6,704	10,589
Amortization of debt issue costs and debt discount	8,525	8,143
Other	142	139
Capitalized interest	(1,440)	(2,677)
Total	$45,903	$49,020

The decrease in interest expense of $3.1 million between periods was mainly due to lower borrowings outstanding under our credit agreement during the first nine months of 2010, which reduced the interest on our credit agreement by $3.9 million. In addition, we incurred lower interest on our Senior Subordinated Notes due to the redemption of $150.0 million of 7.25% notes due 2012 and $220.0 million of 7.25% notes due 2013 in early September 2010, and then at the end of September 2010, we subsequently issued $350.0 million of 6.5% notes due 2018. These decreases in interest were partially offset by lower amounts of capitalized interest between periods. Our weighted average debt outstanding during the first nine months of 2010 was $721.4 million versus $1,080.8 million for the first nine months of 2009. Our weighted average effective cash interest rate was 7.2% during the first nine months of 2010 compared to 5.4% during the first nine months of 2009.

Commodity Derivative (Gain) Loss, Net. During the past three years, we entered into commodity derivative contracts that we did not designate as cash flow hedges. In addition, effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges, and we elected to discontinue all hedge accounting prospectively. Accordingly, beginning April 1, 2009 all of our 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 commodity derivative (gain) loss, net.

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The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Change in unrealized (gains) losses on derivative contracts	$(62,571)	$137,616
Realized cash settlement losses	15,917	11,635
Loss on hedging ineffectiveness	-	22,655
Total	$(46,654)	$171,906

The change in unrealized (gains) losses on derivative contracts increased by $200.2 million between periods due to the fact that (i) there was a significant downward shift in the forward price curve for NYMEX crude oil during the nine months ended September 30, 2010 as compared to the upward shift in the same forward price curve during the nine months ended September 30, 2009, and (ii) we averaged 18.3 MMBbls of crude oil hedged during the nine months ended September 30, 2010, while we averaged 20.5 MMBbls of crude oil hedged during the nine months ended September 30, 2009. During the first quarter of 2009, we recognized a loss of $22.7 million for the ineffective portion of changes in fair value on our commodity derivatives then designated as cash flow hedges.

Income Tax Expense (Benefit). Income tax expense totaled $165.9 million for the first nine months of 2010, as compared to a $51.8 million income tax benefit for the first nine months of 2009. Our effective income tax rate increased from 33.9% for the first nine months of 2009 to 38.0% for the first nine months of 2010. The change in the effective income tax rate between periods was primarily due to the change from net loss in 2009 to net income in 2010.

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Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009

Selected Operating Data:	Three Months Ended September 30, 2010	2009
Net production:		
Oil (MMBbls)	4.9	3.9
Natural gas (Bcf)	6.9	7.1
Total production (MMBOE)	6.1	5.1
Net sales (in millions):		
Oil (1)	$330.8	$232.3
Natural gas (1)	34.4	23.8
Total oil and natural gas sales	$365.2	$256.1
Average sales prices:		
Oil (per Bbl)	$67.02	$58.86
Effect of oil hedges on average price (per Bbl)	(0.92)	(2.42)
Oil net of hedging (per Bbl)	$66.10	$56.44
Average NYMEX price (per Bbl)	$76.21	$68.29
Natural gas (per Mcf)	$5.00	$3.35
Effect of natural gas hedges on average price (per Mcf)	0.02	0.05
Natural gas net of hedging (per Mcf)	$5.02	$3.40
Average NYMEX price (per Mcf)	$4.39	$3.40
Cost and expense (per BOE):		
Lease operating expenses	$11.34	$11.46
Production taxes	$4.31	$3.66
Depreciation, depletion and amortization expense	$16.06	$19.74
General and administrative expenses	$3.20	$2.21

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $109.2 million to $365.2 million in the third quarter of 2010 compared to the same period in 2009. Sales are a function of oil and gas volumes sold and average sales prices. Our oil sales volumes increased 25% between periods, while our natural gas sales volumes decreased 3%. 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, partially offset by production decreases due to pipeline maintenance on the Enbridge system. Oil production from the Bakken increased 880 MBbl compared to the third quarter of 2009, while North Ward Estes oil production increased 115 MBbl and Postle oil production increased 60 MBbl in the third quarter of 2010 over the same prior year period. The gas volume decrease between periods was primarily the result of normal field production decline, which led to gas production decreases of 280 MMcf and 260 MMcf at our Kawitt and Boies Ranch areas, respectively, for the third quarter of 2010 when compared to the third quarter of 2009. These production decreases were partially offset by increased gas production of 320 MMcf in our North Dakota Bakken area and 190 MMcf in our Flat Rock area. Also contributing to the increase in oil and natural gas sales revenue in 2010 were increases in average sales prices. Our average price for oil before the effects of hedging increased 14% between periods, and our average price for natural gas before the effects of hedging increased 49%. In addition to higher average NYMEX pricing during the third quarter of 2010 as compared to the same period in 2009, natural gas sales price increases were also due to fixed-price gas contracts entered into at our Flat Rock and Boies Ranch areas that carried a weighted-average price of $5.33 per Mcf for the third quarter of 2010. These contracts were in effect starting in the latter portion of the fourth quarter of 2009.

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Gain on Hedging Activities. Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges, and we elected to discontinue all hedge accounting prospectively. As a result, we reclassified from AOCI into earnings $4.4 million and $7.8 million in unrealized gains (which were frozen in AOCI on the April 1, 2009 de-designation date) upon the expiration of these de-designated crude oil hedges in the third quarter of 2010 and 2009, respectively. See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas derivatives as of October 15, 2010.

Lease Operating Expenses. Our lease operating expenses during the third quarter of 2010 were $69.0 million, a $10.2 million increase over the same period in 2009. This higher amount of LOE in 2010 was related to increases of $2.0 million in transportation charges, $1.6 million in electricity costs and $1.5 million in ad valorem taxes between periods, as well as a higher level of workover activity. The increase in transportation charges was primarily due to higher transportation fees on non-operated properties in the Bakken. Workovers amounted to $17.4 million in the third quarter of 2010, as compared to $11.6 million in the third quarter of 2009, and this increase in workover activity primarily related to our two CO2 projects. Our lease operating expenses on a BOE basis decreased from $11.46 during the third quarter of 2009 to $11.34 during the third quarter of 2010. The decrease of 1% on a BOE basis was the result of the increase in overall production volumes between periods.

Production Taxes. Our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of credits and exemptions allowed in our various taxing jurisdictions. Our production taxes during the third quarter of 2010 were $26.2 million, a $7.4 million increase over the same period in 2009, primarily due to higher oil and natural gas sales between periods. Our company-wide production tax rates for the third quarter of 2010 and 2009 were 7.2% and 7.3%, respectively, of oil and natural gas sales.

Depreciation, Depletion and Amortization. Our DD&A expense decreased $3.6 million in 2010 as compared to the third quarter of 2009. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended September 30,	
	2010	2009
Depletion	$95,276	$98,876
Depreciation	565	771
Accretion of asset retirement obligations	1,863	1,626
Total	$97,704	$101,273

DD&A decreased in the third quarter of 2010 primarily due to $3.6 million in lower depletion expense between periods. This net decrease in depletion was the result of $22.0 million in lower depletion expense due to a decline in our depletion rate between periods, which effect was largely offset by $18.4 million of additional depletion expense due to higher overall production volumes during the third quarter of 2010. On a BOE basis, our DD&A rate of $16.06 for the third quarter of 2010 was 19% lower than the rate of $19.74 for the same period in 2009. The primary factors causing this lower DD&A rate was a net increase in our estimated proved reserves of 35.9 MMBOE as of December 31, 2009, as well as proved developed and total proved reserves added during the first nine months of 2010. This factor was partially offset by (i) $607.9 million in drilling and development expenditures incurred during the past twelve months and (ii) 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.

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Exploration and Impairment Costs. Our exploration and impairment costs decreased $1.9 million in the third quarter of 2010, as compared to the third quarter of 2009. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended September 30,	
	2010	2009
Exploration	$6,145	$5,973
Impairment	4,355	6,449
Total	$10,500	$12,422

Exploration costs increased $0.2 million during the third quarter of 2010 as compared to the same period in 2009 primarily due to an increase in G&G activity, partially offset by lower exploratory dry hole costs in the third quarter of 2010.

The impairment charges in the third quarter of 2010 and 2009 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. The decrease of $2.1 million in impairment expense between periods, however, was mainly due to a $2.3 million non-cash impairment charge in the third quarter of 2009 for the partial write-down of certain proved properties whose net book values exceeded their undiscounted future cash flows. There were no proved property impairment charges during the third quarter of 2010.

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

	Three Months Ended September 30,	
	2010	2009
General and administrative expenses	$32,980	$24,417
Reimbursements and allocations	(13,500)	(13,103)
General and administrative expense, net	$19,480	$11,314

General and administrative expenses before reimbursements and allocations increased $8.6 million to $33.0 million during the third quarter of 2010. The largest component of the increase related to $3.5 million in additional employee compensation in the third quarter of 2010 related to higher stock compensation between periods, personnel hired during the past twelve months and general pay increases. In addition to these higher employee compensation costs, there was $2.7 million in higher accrued distributions under the Plan between periods, and we incurred $2.2 million of offering costs in 2010 related to the preferred stock exchange offer completed in September. The increase in reimbursements and allocations in the third quarter of 2010 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales increased from 4% for the third quarter of 2009 to 5% for the third quarter of 2010.

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

	Three Months Ended September 30,	
	2010	2009
Senior Subordinated Notes	$9,810	$11,081
Credit agreement	2,596	2,436
Amortization of debt issue costs and debt discount	2,801	2,968
Other	29	26
Capitalized interest	(657)	(864)
Total	$14,579	$15,647

The decrease in interest expense of $1.1 million between periods was mainly due to the redemption of $150.0 million of 7.25% notes due 2012 and $220.0 million of 7.25% notes due 2013 in early September 2010, and then at the end of September 2010 we subsequently issued $350.0 million of 6.5% notes due 2018. Together these refinancing transactions had the aggregate effect of reducing the interest on our Senior Subordinated Notes between periods by $1.3 million. Our weighted average debt outstanding during the third quarter of 2010 was $674.7 million versus $824.9 million for the third quarter of 2009. Our weighted average effective cash interest rate was 7.4% during the third quarter of 2010 compared to 6.6% during the third quarter of 2009.

Commodity Derivative (Gain) Loss, Net. During the third quarter of 2010 and 2009, all of our derivative contracts were marked-to-market each quarter with fair value gains and losses recognized immediately in earnings. Cash flow is only impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded immediately to earnings as commodity derivative (gain) loss, net.

The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Three Months Ended September 30,	
	2010	2009
Change in unrealized (gains) losses on derivative contracts	$27,407	$(19,567)
Realized cash settlement losses	4,358	9,176
Total	$31,765	$(10,391)

The change in unrealized (gains) losses on derivative contracts increased by $47.0 million between periods due to the fact that there was a significant upward shift in the forward price curve for NYMEX crude oil during the three months ended September 30, 2010 as compared to the downward shift in the same forward price curve during the three months ended September 30, 2009.

Income Tax Expense (Benefit). Income tax expense totaled $35.9 million for the third quarter of 2010, as compared to $26.3 million for the third quarter of 2009. Our effective income tax rate decreased from 42.3% for the third quarter of 2009 to 38.0% for the third quarter of 2010. The change in the effective income tax rate between periods was primarily due to the change from net loss in 2009 to net income in 2010.

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Liquidity and Capital Resources

Overview. At September 30, 2010, our debt to total capitalization ratio was 22.1%, we had $3.2 million of cash on hand and $2,465.4 million of stockholders' equity. At December 31, 2009, our debt to total capitalization ratio was 25.6%, we had $12.0 million of cash on hand and $2,270.1 million of stockholders' equity. In the first nine months of 2010, we generated $720.3 million of cash provided by operating activities, an increase of $429.4 million over the same period in 2009. Cash provided by operating activities increased primarily due to higher oil production volumes and higher average sales prices for both crude oil and natural gas. These positive factors were partially offset by lower gas production volumes in the first nine months of 2010, as well as increased production taxes, lease operating expenses and general and administrative expenses during the first nine months of 2010 as compared to the same period in 2009. Cash flows from operating activities were used to finance $473.7 million of drilling and development expenditures and $102.3 million of cash acquisition capital expenditures paid in the first nine months of 2010, net repayments under our credit agreement totaling $60.0 million, the premium of $47.5 million for the induced conversion of our convertible perpetual preferred stock and the payment of preferred stock dividends totaling $16.2 million. The following chart details our exploration and development expenditures incurred by region during the first nine months of 2010 (in thousands):

	Drilling and Development Expenditures (1)	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$322,273	$12,630	$334,903	62%
Permian Basin	143,431	7,963	151,394	28%
Mid-Continent	31,171			