WHITING PETROLEUM CORP
Form 10-Q
July 30, 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 June 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 July 15, 2010: 50,998,477 shares.

TABLE OF CONTENTS

Certain Definitions		1
	PART I — FINANCIAL INFORMATION	
Item 1.	Consolidated Financial Statements (Unaudited)	2
	Consolidated Balance Sheets as of June 30, 2010 and December 31, 2009	2
	Consolidated Statements of Income for the Three and Six Months Ended June 30, 2010 and 2009	4
	Consolidated Statements of Cash Flows for the Six Months Ended June 30, 2010 and 2009	5
	Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Six Months Ended June 30, 2010 and 2009	6
	Notes to Consolidated Financial Statements	7
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	20
Item 3.	Quantitative and Qualitative Disclosures about Market Risk	38
Item 4.	Controls and Procedures	40
	PART II — OTHER INFORMATION	
Item 1.	Legal Proceedings	41
Item 1A.	Risk Factors	41
Item 6.	Exhibits	41
	Certification of the Chairman, President and CEO	
	Certification of the Vice President and CFO	
	Written Statement of the Chairman, President and CEO	
	Written Statement of the Vice President and CFO	

Table of Contents

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.

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

“plugging and abandonment” - Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

“working interest” - The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property; to share in production, subject to all royalties, overriding royalties and other burdens; and to share in all costs of exploration, development, operations and all risks in connection therewith.

Table of Contents

PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

WHITING PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS (Unaudited)
(In thousands)

	June 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 15,521	$ 11,960
Accounts receivable trade, net	169,109	152,082
Derivative assets	7,440	4,723
Prepaid expenses and other	9,593	7,260
Total current assets	201,663	176,025
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	5,152,879	4,870,688
Unproved properties	123,213	100,706
Other property and equipment	94,593	100,833
Total property and equipment	5,370,685	5,072,227
Less accumulated depreciation, depletion and amortization	(1,450,636)	(1,274,121)
Total property and equipment, net	3,920,049	3,798,106
DEBT ISSUANCE COSTS	19,667	24,672
DERIVATIVE ASSETS	8,580	8,473
OTHER LONG-TERM ASSETS	22,766	22,266
TOTAL	$ 4,172,725	$ 4,029,542

See notes to consolidated financial statements. (Continued)

Table of Contents

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

	June 30, 2010	December 31, 2009
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 13,904	$ 14,023
Accrued capital expenditures	56,158	29,998
Accrued liabilities	69,179	62,891
Accrued interest	10,514	10,501
Oil and gas sales payable	64,593	46,327
Accrued employee compensation and benefits	18,405	22,105
Production taxes payable	22,473	21,188
Deferred gain on sale	12,776	12,966
Derivative liabilities	26,269	49,551
Deferred income taxes	5,811	11,325
Tax sharing liability	1,857	1,857
Total current liabilities	301,939	282,732
NON-CURRENT LIABILITIES:		
Long-term debt	649,603	779,585
Deferred income taxes	464,343	341,037
Derivative liabilities	73,750	137,621
Production Participation Plan liability	75,125	69,433
Asset retirement obligations	72,216	66,846
Deferred gain on sale	50,880	58,462
Tax sharing liability	21,444	20,744
Other long-term liabilities	3,091	2,997
Total non-current liabilities	1,410,452	1,476,725
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 3,450,000 shares issued and outstanding as of June 30, 2010 and December 31, 2009, aggregate liquidation preference of $345,000,000	3	3
Common stock, $0.001 par value, 175,000,000 shares authorized; 51,441,800 issued and 50,998,477 outstanding as of June 30, 2010, 51,363,638 issued and 50,845,374 outstanding as of December 31, 2009	51	51
Additional paid-in capital	1,545,370	1,546,635
Accumulated other comprehensive income	10,780	20,413
Retained earnings	904,130	702,983

Total stockholders’ equity		2,460,334		2,270,085
TOTAL	$	4,172,725	$	4,029,542

See notes to consolidated financial statements. (Concluded)

Table of Contents

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

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
REVENUES AND OTHER INCOME:				
Oil and natural gas sales	$ 363,028	$ 214,303	$ 703,722	$ 360,478
Gain on hedging activities	8,525	6,848	15,259	20,298
Amortization of deferred gain on sale	4,022	4,274	7,759	8,373
Gain on sale of properties	1,918	4,608	1,918	4,608
Interest income and other	134	125	240	240
Total revenues and other income	377,627	230,158	728,898	393,997
COSTS AND EXPENSES:				
Lease operating	67,730	57,582	128,585	118,536
Production taxes	26,050	14,914	51,148	24,433
Depreciation, depletion and amortization	94,583	100,315	192,132	200,349
Exploration and impairment	14,509	9,792	27,415	27,106
General and administrative	15,402	10,282	29,036	19,262
Interest expense	15,632	18,693	31,324	33,373
Change in Production Participation Plan liability	4,747	3,284	5,692	3,680
Commodity derivative (gain) loss, net	(63,496)	160,532	(78,418)	182,297
Total costs and expenses	175,157	375,394	386,914	609,036
INCOME (LOSS) BEFORE INCOME TAXES	202,470	(145,236)	341,984	(215,039)
INCOME TAX EXPENSE (BENEFIT):				
Current	5,308	-	6,638	(539)
Deferred	71,845	(52,073)	123,418	(77,578)
Total income tax expense (benefit)	77,153	(52,073)	130,056	(78,117)
NET INCOME (LOSS)	125,317	(93,163)	211,928	(136,922)
Preferred stock dividends	(5,391)	-	(10,781)	-
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ 119,926	$ (93,163)	$ 201,147	$ (136,922)
	$ 2.35	$ (1.83)	$ 3.95	$ (2.78)

EARNINGS (LOSS) PER COMMON SHARE, BASIC				
EARNINGS (LOSS) PER COMMON SHARE, DILUTED	$ 2.12	$ (1.83)	$ 3.58	$ (2.78)
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	50,995	50,842	50,953	49,230
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	59,225	50,842	59,234	49,230

See notes to consolidated financial statements.

Table of Contents

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

	Six Months Ended June 30, 2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 211,928	$ (136,922)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	192,132	200,349
Deferred income tax expense (benefit)	123,418	(77,578)
Amortization of debt issuance costs and debt discount	5,024	4,355
Accretion of tax sharing liability	700	819
Stock-based compensation	4,390	2,577
Amortization of deferred gain on sale	(7,759)	(8,373)
Gain on sale of properties	(1,918)	(4,608)
Undeveloped leasehold and oil and gas property impairments	7,700	8,295
Exploratory dry hole costs	2,597	54
Change in Production Participation Plan liability	5,692	3,680
Unrealized (gain) loss on derivative contracts	(105,236)	172,991
Other non-current	(2,287)	(2,754)
Changes in current assets and liabilities:		
Accounts receivable trade	(17,027)	17,866
Prepaid expenses and other	(2,333)	26,306
Accounts payable and accrued liabilities	7,248	(24,321)
Accrued interest	13	1,428
Other current liabilities	15,851	(39,155)
Net cash provided by operating activities	440,133	145,009
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(33,963)	(38,691)
Drilling and development capital expenditures	(264,015)	(327,894)
Proceeds from sale of oil and gas properties	7,842	79,609
Net cash used in investing activities	(290,136)	(286,976)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of 6.25% convertible perpetual preferred stock	-	334,562
Issuance of common stock	-	234,753
Preferred stock dividends paid	(10,781)	-
Long-term borrowings under credit agreement	240,000	260,000
Repayments of long-term borrowings under credit agreement	(370,000)	(660,000)
Debt issuance costs	-	(23,141)
Restricted stock used for tax withholdings	(5,655)	(653)
Net cash (used in) provided by financing activities	(146,436)	145,521
NET CHANGE IN CASH AND CASH EQUIVALENTS	3,561	3,554
CASH AND CASH EQUIVALENTS:		
Beginning of period	11,960	9,624

End of period	$ 15,521	$ 13,178

See notes to consolidated financial statements.

Table of Contents

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

	Preferred Stock		Common Stock						
	Shares	Amount	Shares	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	-	-	-	-	-	-	(136,922)	(136,922)	$ (136,922)
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 $8,433	-	-	-	-	-	14,433	-	14,433	14,433
OCI amortization on de-designated hedges, net of taxes of $2,272	-	-	-	-	-	(4,576)	-	(4,576)	(4,576)
Total comprehensive income									$ (122,234)
Issuance of 6.25% convertible perpetual preferred stock	3,450	3	-	-	334,559	-	-	334,562	
Issuance of stock, secondary offering	-	-	8,450	8	234,745	-	-	234,753	
Restricted stock issued			364	-	-	-	-	-	
Restricted stock forfeited	-	-	(3)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(27)	-	(654)	-	-	(654)	
Tax effect from restricted stock vesting	-	-	-	-	(515)	-	-	(515)	
Stock-based compensation	-	-	-	-	2,577	-	-	2,577	
BALANCES-June 30, 2009	3,450	$ 3	51,366	$ 51	$ 1,542,022	$ 31,959	$ 683,245	$ 2,257,280	

BALANCES-January 1, 2010	3,450	$ 3	51,364	$ 51	$ 1,546,635	$ 20,413	$ 702,983	$ 2,270,085	
Net income	-	-	-	-	-	-	211,928	211,928	$ 211,928
OCI amortization on de-designated hedges, net of taxes of $5,626	-	-	-	-	-	(9,633)	-	(9,633)	(9,633)
Total comprehensive income									$ 202,295
Restricted stock issued	-	-	161	-	-	-	-	-	
Restricted stock forfeited	-	-	(6)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(77)	-	(5,655)	-	-	(5,655)	
Stock-based compensation	-	-	-	-	4,390	-	-	4,390	
Preferred dividends paid	-	-	-	-	-	-	(10,781)	(10,781)	
BALANCES-June 30, 2010	3,450	$ 3	51,442	$ 51	$ 1,545,370	$ 10,780	$ 904,130	$ 2,460,334	

See notes to consolidated financial statements.

6

Table of Contents

WHITING PETROLEUM CORPORATION
NOTES TO CONSOLIDATED
FINANCIAL STATEMENTS (Unaudited)

1. BASIS OF PRESENTATION

Description of Operations—Whiting Petroleum Corporation, a Delaware corporation, is an independent oil and gas company that 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.

2. ACQUISITIONS AND DIVESTITURES

2010 Activity

There were no significant acquisitions or divestitures during the first half 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.

Table of Contents

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.

3. LONG-TERM DEBT

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

	June 30, 2010	December 31, 2009
Credit Agreement	$30,000	$160,000
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $961 and $1,147, respectively	219,039	218,853
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $206 and $268, respectively	150,564	150,732
Total debt	$649,603	$779,585

Credit Agreement—As of June 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 has a borrowing base of $1.1 billion with $1,069.6 million of available borrowing capacity, which is net of $30.0 million in borrowings and $0.4 million in letters of credit outstanding. The credit agreement provides for interest only payments until April 2012, when the agreement expires and all outstanding borrowings are due.

Table of Contents

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Whiting Oil and Gas may, throughout the term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect at any given time. A portion of the revolving credit agreement in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company. As of June 30, 2010, $49.6 million was available for additional letters of credit under the agreement.

Interest accrues at the Company's option at either (i) a base rate for a base rate loan plus the margin in the table below, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% or an adjusted LIBOR rate plus 1.00%, or (ii) an adjusted LIBOR rate for a Eurodollar loan plus the margin in the table below. 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, which are included as a component of interest expense. At June 30, 2010, the weighted average interest rate on the outstanding principal balance under the credit agreement was 2.4%.

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 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 4.5 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 include the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement restricts 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 June 30, 2010.

The obligations of Whiting Oil and Gas under the credit agreement are secured by a first lien on substantially all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation has 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.

Table of Contents

Senior Subordinated Notes—In October 2005, the Company issued at par $250.0 million of 7% Senior Subordinated Notes due 2014. The estimated fair value of these notes was $254.4 million as of June 30, 2010, based on quoted market prices for these same debt securities.

In April 2005, the Company issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount of $3.3 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.4%. The estimated fair value of these notes was $221.1 million as of June 30, 2010, based on quoted market prices for these same debt securities.

In May 2004, the Company issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount of $1.1 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.3%. The estimated fair value of these notes was $150.0 million as of June 30, 2010, based on quoted market prices for these same debt securities.

The notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of Whiting Oil and Gas' credit agreement. The Company's obligations under the notes are fully, unconditionally, jointly and severally guaranteed by all of the Company's wholly-owned operating subsidiaries, Whiting Oil and Gas and Whiting Programs, Inc. (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 June 30, 2010 and December 31, 2009 were $9.3 million and $10.3 million, respectively, and are included in accrued liabilities. The following table provides a reconciliation of the Company's asset retirement obligations for the six months ended June 30, 2010 (in thousands):

Asset retirement obligation, January 1, 2010	$77,186
Additional liability incurred	626
Revisions in estimated cash flows	4,976
Accretion expense	3,558
Obligations on sold properties	(2,942)
Liabilities settled	(1,927)
Asset retirement obligation, June 30, 2010	$81,477

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.

10

Table of Contents

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 July 1, 2010.

	Whiting Petroleum Corporation			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jul – Dec 2010	4,096,630	240,001	$63.38 - $89.74	$6.49 - $14.10
Jan – Dec 2011	4,435,039	436,510	$49.95 - $93.38	$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	15,686,760	1,060,513		

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			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jul – Dec 2010	61,630	240,001	$76.00 - $135.00	$6.49 - $14.10

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	281,760	1,060,513		

Table of Contents

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			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jul – Dec 2010	193,040	751,739	$76.00 - $135.00	$6.49 - $14.10
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	882,540	3,321,773		

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 has 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 six months ended June 30, 2010, $8.5 million ($5.4 million net of tax) and $15.3 million ($9.6 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 June 30, 2010, accumulated other comprehensive income amounted to $17.1 million ($10.8 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 $8.5 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).

Table of Contents

Not Designated as ASC 815 Hedges	Balance Sheet Classification	Fair Value June 30, 2010	Fair Value December 31, 2009
Derivative assets			
Commodity contracts	Current derivative assets	$7,440	$4,723
Commodity contracts	Non-current derivative assets	8,580	8,473
Total derivative assets		$16,020	$13,196
Derivative liabilities			
Commodity contracts	Current derivative liabilities	$26,269	$49,551
Commodity contracts	Non-current derivative liabilities	73,750	137,621
Total derivative liabilities		$100,019	$187,172

The following tables summarize the effects of commodity derivatives instruments on the consolidated statements of income for the three and six months ended June 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)	
		Six Months Ended June 30,	
		2010	2009
Commodity contracts	Other comprehensive income	$-	$21,147
		Three Months Ended June 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)	
		Six Months Ended June 30,	
		2010	2009
Commodity contracts	Gain on hedging activities	$15,259	$20,298
		Three Months Ended June 30,	
		2010	2009
Commodity contracts	Gain on hedging activities	$8,525	$6,848

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Loss Recognized in Income (Ineffective Portion)	
		Six Months Ended June 30,	
		2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$-	$22,866
		Three Months Ended June 30,	
		2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$-	$-

Table of Contents

Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income	
		Six Months Ended June 30,	
		2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$(78,418)	$159,431
		Three Months Ended June 30,	
		2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$(63,496)	$160,532

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.

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 June 30, 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

Table of Contents

	Level 1	Level 2	Level 3	Total Fair Value June 30, 2010
Financial Assets				
Commodity derivatives - current	$-	$7,440	$-	$7,440
Commodity derivatives - non-current	-	8,580	-	8,580
Total financial assets	$-	$16,020	$-	$16,020
Financial Liabilities				
Commodity derivatives - current	$-	$26,269	$-	$26,269
Commodity derivatives - non-current	-	73,750	-	73,750
Total financial liabilities	$-	$100,019	$-	$100,019

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.

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 June 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 June 30, 2010	Fair Value Measurements Using Level 1	Level 2	Level 3	Pre-tax (Gain) Loss Six Months Ended June 30, 2010
Asset retirement obligations	$633	$-	$-	$626	$-
Total non-recurring assets at fair value	$633	$-	$-	$626	$-

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 six months ended June 30, 2010 and 2009 amounted to $14.1 million and $5.7 million, respectively, charged to general and administrative expense and $1.9 million and $0.8 million, respectively, charged to exploration expense.

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

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At June 30, 2010, the Company used three-year average historical NYMEX prices of $78.65 for crude oil and $6.05 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 prices at June 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 $123.8 million. This amount includes $13.9 million attributable to proved undeveloped oil and gas properties and $16.0 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 and change in estimates	21,644
Reduction in liability for cash payments accrued and recognized as compensation expense	(15,952)
Long-term Production Participation Plan liability, June 30, 2010	$75,125

8. STOCKHOLDERS' EQUITY

Common Stock Share Increase—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.

6.25% Convertible Perpetual Preferred Stock Offering—In June 2009, the Company completed a public offering of 6.25% convertible perpetual 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 convertible perpetual 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. During the first six months of 2010, the Company paid dividends of $10.8 million. Each share of convertible perpetual 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 convertible perpetual 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 convertible preferred stock have no voting rights unless dividends payable on the convertible preferred stock are in arrears for six or more quarterly periods.

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.

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 six months ended June 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.

Table of Contents

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 June 30, 2010	2009
Basic Earnings Per Share		
Numerator:		
Net income (loss)	$125,317	$(93,163)
Preferred stock dividends	(5,391)	-
Net income (loss) available to common shareholders, basic	$119,926	$(93,163)
Denominator:		
Weighted average shares outstanding, basic	50,995	50,842
Diluted Earnings Per Share		
Numerator:		
Net income (loss) available to common shareholders, basic	$119,926	$(93,163)
Preferred stock dividends	5,391	-
Adjusted net income (loss) available to common shareholders, diluted	$125,317	$(93,163)
Denominator:		
Weighted average shares outstanding, basic	50,995	50,842
Restricted stock and stock options	284	-
Convertible perpetual preferred stock	7,946	-
Weighted average shares outstanding, diluted	59,225	50,842
Earnings (loss) per common share, basic	$2.35	$(1.83)
Earnings (loss) per common share, diluted	$2.12	$(1.83)

For the three months ended June 30, 2009, the Company had a net loss. Therefore, the diluted earnings per share calculation for that period excludes the effect of 218,331 shares of restricted stock and stock options, as well as 611,256 weighted average shares of convertible preferred stock outstanding because their effect was anti-dilutive.

	Six Months Ended June 30, 2010	2009
Basic Earnings Per Share		
Numerator:		
Net income (loss)	$211,928	$(136,922)
Preferred stock dividends	(10,781)	-
Net income (loss) available to common shareholders, basic	$201,147	$(136,922)
Denominator:		
Weighted average shares outstanding, basic	50,953	49,230

Table of Contents

	Six Months Ended June 30,	
	2010	2009
Diluted Earnings Per Share		
Numerator:		
Net income (loss) available to common shareholders, basic	$201,147	$(136,922)
Preferred stock dividends	10,781	-
Adjusted net income (loss) available to common shareholders, diluted	$211,928	$(136,922)
Denominator:		
Weighted average shares outstanding, basic	50,953	49,230
Restricted stock and stock options	335	-
Convertible perpetual preferred stock	7,946	-
Weighted average shares outstanding, diluted	59,234	49,230
Earnings (loss) per common share, basic	$3.95	$(2.78)
Earnings (loss) per common share, diluted	$3.58	$(2.78)

For the six months ended June 30, 2009, the Company had a net loss. Therefore, the diluted earnings per share calculation for that period excludes the effect of 158,661 shares of restricted stock and stock options, as well as 307,316 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.

Table of Contents

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

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

Overview

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

As demonstrated by our recent capital expenditure programs, we are increasingly focused on a 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.

Table of Contents

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 half 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 and $77.99 per Bbl for the first and second 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 half of 2010. For example, daily average NYMEX natural gas prices declined to $3.99 per Mcf for 2009, but rose to $4.69 per Mcf for the first half 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.

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 114% from 10.2 MBOE/d in June 2009 to 21.8 MBOE/d in June 2010. From January 1 through July 20 2010, we completed 40 operated wells in the Sanish field, bringing to 108 the total number of operated wells in the field. As of July 20, 2010, 11 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 increased 6% from 5.3 MBOE/d in June 2009 to 5.6 MBOE/d in June 2010.

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 second quarter of 2010, the field produced at an average net rate of 9.6 MBOE/d, representing a 22% increase from the 7.8 MBOE/d rate in the second quarter of 2009.

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 22% from 6.3 MBOE/d in the second quarter of 2009 to 7.7 MBOE/d in the second 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.

Table of Contents

Results of Operations

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Selected Operating Data:	Six Months Ended June 30, 2010	2009
Net production:		
Oil (MMBbls)	9.1	7.3
Natural gas (Bcf)	13.2	15.5
Total production (MMBOE)	11.3	9.9
Net sales (in millions):		
Oil (1)	$636.8	$307.3
Natural gas (1)	66.9	53.2
Total oil and natural gas sales	$703.7	$360.5
Average sales prices:		
Oil (per Bbl)	$70.23	$41.85
Effect of oil hedges on average price (per Bbl)	(1.33)	1.40
Oil net of hedging (per Bbl)	$68.90	$43.25
Average NYMEX price (per Bbl)	$78.39	$51.46
Natural gas (per Mcf)	$5.07	$3.44
Effect of natural gas hedges on average price (per Mcf)	0.04	0.04
Natural gas net of hedging (per Mcf)	$5.11	$3.48
Average NYMEX price (per Mcf)	$4.69	$4.21
Cost and expense (per BOE):		
Lease operating expenses	$11.41	$11.95
Production taxes	$4.54	$2.46
Depreciation, depletion and amortization expense	$17.05	$20.19
General and administrative expenses	$2.58	$1.94

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $343.2 million to $703.7 million in the first half of 2010 compared to the same period in 2009. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 23% between periods, while our natural gas sales volumes decreased 15%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area in addition to increased production at our two large CO_2 projects, Postle and North Ward Estes. Oil production from the Bakken increased 1,345 MBbl compared to the first half of 2009, while Postle oil production increased 315 MBbl and North Ward Estes oil production increased 295 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 965 MMcf and 905 MMcf at our Boies Ranch and Kawitt areas, respectively, compared to the first six months of 2009. These production decreases were partially offset by increased gas production of 780 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 68% between periods, and our average price for natural gas before the effects of hedging increased 47%. In addition to higher NYMEX pricing during the first half 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 $5.36 per Mcf for the first half of 2010. These contracts were in effect starting in the latter portion of the fourth quarter of 2009.

Table of Contents

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 as of March 31, 2009 and have elected to discontinue hedge accounting prospectively. Accordingly, 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 these unrealized gains as gain on hedging activites. Prior to April 1, 2009, however, realized cash settlements gains or losses on hedge-designated crude oil derivatives were also included in gain (loss) on hedging activities.

Our gain on hedging activities decreased $5.0 million in 2010 as compared to the first half of 2009. The components of our gain on hedging activities were as follows (in thousands):

	Six Months Ended June 30,	
	2010	2009
Gains reclassified from AOCI on de-designated hedges	$15,259	$6,848
Realized cash settlement gains on crude oil derivatives	-	13,450
Total	$15,259	$20,298

None of our natural gas derivatives were designated as cash flow hedges during the first six months of 2010 or 2009. See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas derivatives as of July 1, 2010.

Amortization of Deferred Gain on Sale. In connection with the sale of 11,677,500 Trust units to the public in April 2008 and the related oil and gas property conveyance, we recognized a deferred gain on sale of $100.1 million. This deferred gain is amortized to income over the life of the Trust on a units-of-production basis. For the six months ended June 30, 2010 and 2009, we recognized $7.8 million and $8.4 million, respectively, in income as amortization of deferred gain on sale.

Gain on Sale of Properties. During the six months ended June 30, 2010, we sold our interest in several non-core properties for aggregate proceeds of $7.8 million in cash, which resulted in a pre-tax gain on sale of $1.9 million. During the six months ended June 30, 2009, we entered into a participation agreement with a privately held independent oil company covering acreage located primarily in the western portion of the Sanish field in Mountrail County, North Dakota. At the closing of the agreement, the private company paid us $107.3 million, resulting in a pre-tax gain on sale of $4.6 million.

Lease Operating Expenses. Our lease operating expenses ("LOE") during the first six months of 2010 were $128.6 million, a $10.0 million increase over the same period in 2009. This higher amount of LOE in 2010 was related to increases of $3.4 million in ad valorem taxes, $3.3 million in transportation charges and $2.2 million in electric power 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 $31.0 million in the first half of 2010, as compared to $26.3 million in the first half of 2009, and this increase in workover activity primarily related to our two CO_2 projects, which are evolving past the construction and start-up phases and moving into an ongoing maintenance and repair phase that involves a significantly higher number of producing and injection wells. Our lease operating expenses on a BOE basis, however, decreased from $11.95 during the first six months of 2009 to $11.41 during the first six months of 2010. This decrease of 5% on a BOE basis was primarily caused by increased oil and natural gas production volumes.

Table of Contents

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 six months of 2010 were $51.1 million, a $26.7 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 half of 2010 and 2009 were 7.3% and 6.8%, respectively, of oil and natural gas sales. Our production tax rate for the first half of 2010 was greater than the rate for same period in 2009 mainly due to successful wells completed during the second half of 2009 and the first half of 2010 in the North Dakota Bakken area, which has an 11.5% production tax rate.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense decreased $8.2 million in 2010 as compared to the first half of 2009. The components of our DD&A expense were as follows (in thousands):

	Six Months Ended June 30,	
	2010	2009
Depletion	$ 187,569	$ 194,993
Depreciation	1,005	1,599
Accretion of asset retirement obligations	3,558	3,757
Total	$ 192,132	$ 200,349

DD&A decreased in the first half of 2010 primarily due to $7.4 million in lower depletion expense between periods. This net decrease in depletion of $7.4 million was the result of $33.8 million in lower depletion expense due to a decline in our depletion rate between periods, which effect was largely offset by $26.4 million in higher oil and gas volumes produced during the first half of 2010. On a BOE basis, our DD&A rate of $17.05 for the first half of 2010 was 16% lower than the rate of $20.19 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 half of 2010. These increases in proved reserves drove our DD&A rate substantially lower during the first half of 2010, as compared to our DD&A rate during the first half of 2009. This factor was partially offset by (i) $455.2 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 increased $0.3 million in the first half of 2010, as compared to the first half of 2009. The components of our exploration and impairment costs were as follows (in thousands):

	Six Months Ended June 30,	
	2010	2009
Exploration	$ 19,715	$ 18,811
Impairment	7,700	8,295
Total	$ 27,415	$ 27,106

Table of Contents

Exploration costs increased $0.9 million during the first half of 2010 as compared to the same period in 2009 primarily due to an increase in geological and geophysical (“G&G”) activity and higher exploratory dry hole costs, partially offset by reduced rig termination fees. G&G costs amounted to $9.7 million during the first half of 2010, as compared to $5.1 million during the same period in 2009. During the first half of 2010, we drilled one exploratory dry hole in the Gulf Coast region totaling $2.6 million, while we did not drill any exploratory dry holes during the first half of 2009. These increases were partially offset by reduced rig termination fees recognized in the first half of 2010. No rig termination fees were paid during the first half of 2010, while rig termination fees totaled $7.5 million during the first half of 2009. The impairment charges in the first half of 2010 and 2009 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties.

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):

	Six Months Ended June 30,	
	2010	2009
General and administrative expenses	$55,392	$43,683
Reimbursements and allocations	(26,356)	(24,421)
General and administrative expense, net	$29,036	$19,262

General and administrative expense before reimbursements and allocations increased $11.7 million to $55.4 million during the first half of 2010. The largest component of the increase related to $9.4 million in higher accrued distributions under our Production Participation Plan (the “Plan”) between periods. Plan distributions increased 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 half of 2010 as compared to the same period in 2009. In addition to these higher accrued Plan distributions, there was $4.0 million in additional employee compensation in the first six months of 2010 related to higher stock compensation between periods, personnel hired during the past twelve months and general pay increases. The increase in reimbursements and allocations in the first half 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 decreased from 5% for the first six months of 2009 to 4% for the first six months of 2010.

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

	Six Months Ended June 30,	
	2010	2009
Senior Subordinated Notes	$22,162	$21,745
Credit Agreement	4,108	8,153
Amortization of debt issue costs and debt discount	5,024	4,355
Other	813	933
Capitalized interest	(783)	(1,813)
Total	$31,324	$33,373

The decrease in interest expense of $2.0 million between periods was mainly due to lower borrowings outstanding under our credit agreement during the first half of 2010, which reduced the interest on our credit agreement by $4.0 million. The decrease in interest on our credit agreement was partially offset by higher debt issue cost amortization associated with additional issuance costs incurred in April 2009 when renewing our credit agreement, as well as lower amounts of capitalized interest between periods. Our weighted average debt outstanding during the first half of 2010 was $745.2 million versus $1,210.9 million for the first half of 2009. Our weighted average effective cash interest rate was 7.1% during the first half of 2010 compared to 5.0% during the first half of 2009.

Table of Contents

Change in Production Participation Plan Liability. For the six months ended June 30, 2010, this non-cash expense was $5.7 million, an increase of $2.0 million as compared to the same period in 2009. This expense in 2010 represents the change in the vested present value of estimated future payments to be made after 2011 to participants under our Plan. Although payments take place over the life of the Plan's oil and gas properties, which for some properties is over 20 years, we expense the present value of estimated future payments over the Plan's five-year vesting period. This expense in 2010 and 2009 primarily reflected (i) changes to future cash flow estimates stemming from the volatile commodity price environment during each respective year, (ii) recent drilling activity and property acquisitions, and (iii) employees' continued vesting in the Plan. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

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 as of March 31, 2009 and have elected to discontinue 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.

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

	Six Months Ended June 30,	
	2010	2009
Change in unrealized (gains) losses on derivative contracts	$(89,977)	$156,973
Realized cash settlement losses	11,559	2,458
Loss on hedging ineffectiveness	-	22,866
Total	$(78,418)	$182,297

The change in unrealized (gains) losses on derivative contracts increased by $247.0 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 six months ended June 30, 2010 as compared to the upward shift in the same forward price curve during the six months ended June 30, 2009, and (ii) we averaged 17.4 MMBbls of crude oil hedged during the six months ended June 30, 2010, while we averaged 21.3 MMBbls of crude oil hedged during the six months ended June 30, 2009. During the first six months of 2009, we recognized a loss of $22.9 million for the ineffective portion of changes in fair value on our commodity derivatives designated as cash flow hedges.

Income Tax Expense (Benefit). Income tax expense totaled $130.1 million for the first six months of 2010, as compared to a $78.1 million income tax benefit for the first six months of 2009. Our effective income tax rate increased from 36.3% for the first half of 2009 to 38.0% for the first half of 2010.

Table of Contents

Net Income (Loss) Available to Common Shareholders. Net income (loss) available to common shareholders increased from a $136.9 million loss during the first half of 2009 to $201.1 million in income for the first half of 2010. The primary reasons for this increase include a 14% increase in equivalent volumes sold; a 59% increase in oil prices (net of hedging); a 47% increase in natural gas prices (net of hedging); higher unrealized commodity derivative gains; lower DD&A and interest expense. These positive factors were partially offset by lower gain on sale of properties and amortization of deferred gain on sale; higher production taxes, dividends paid on preferred stock, lease operating expenses, general and administrative expenses, Production Participation Plan expense, exploration and impairment and income taxes during the first half of 2010.

Table of Contents

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

Selected Operating Data:	Three Months Ended June 30, 2010	2009
Net production:		
Oil (MMBbls)	4.8	3.8
Natural gas (Bcf)	6.6	7.6
Total production (MMBOE)	5.9	5.0
Net sales (in millions):		
Oil (1)	$333.0	$191.0
Natural gas (1)	30.0	23.3
Total oil and natural gas sales	$363.0	$214.3
Average sales prices:		
Oil (per Bbl)	$69.78	$50.66
Effect of oil hedges on average price (per Bbl)	(0.68)	(1.15)
Oil net of hedging (per Bbl)	$69.10	$49.51
Average NYMEX price (per Bbl)	$77.99	$59.62
Natural gas (per Mcf)	$4.52	$3.08
Effect of natural gas hedges on average price (per Mcf)	0.04	0.05
Natural gas net of hedging (per Mcf)	$4.56	$3.13
Average NYMEX price (per Mcf)	$4.09	$3.50
Cost and expense (per BOE):		
Lease operating expenses	$11.52	$11.44
Production taxes	$4.43	$2.96
Depreciation, depletion and amortization expense	$16.09	$19.93
General and administrative expenses	$2.62	$2.04

(1) Before consideration of hedging transactions.

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $148.7 million to $363.0 million in the second quarter of 2010 compared to the same period in 2009. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 27% between periods, while our natural gas sales volumes decreased 13%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area in addition to increased production at our two large CO_2 projects, Postle and North Ward Estes. Oil production from the Bakken increased 805 MBbl compared to the second quarter of 2009, while Postle oil production increased 155 MBbl and North Ward Estes oil production increased 150 MBbl in the second 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 415 MMcf and 375 MMcf at our Boies Ranch and Kawitt areas, respectively, compared the second quarter of 2009. These production decreases were partially offset by increased gas production of 385 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 38% between periods, and our average price for natural gas before the effects of hedging increased 47%. In addition to higher NYMEX pricing during the second 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 $5.36 per Mcf for the second quarter of 2010. These contracts were in effect starting in the latter portion of the fourth quarter of 2009.

Table of Contents

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 as of March 31, 2009 and have elected to discontinue hedge accounting prospectively. As a result, we reclassified from AOCI into earnings \$8.5 million and \$6.8 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 second quarter of 2010 and 2009, respectively. None of our natural gas derivatives were designated as cash flow hedges during the second quarter of 2010 or 2009. See Item 3, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas derivatives as of July 1, 2010.

Amortization of Deferred Gain on Sale. In connection with the sale of 11,677,500 Trust units to the public in April 2008 and the related oil and gas property conveyance, we recognized a deferred gain on sale of \$100.1 million. This deferred gain is amortized to income over the life of the Trust on a units-of-production basis. For the three months ended June 30, 2010 and 2009, we recognized \$4.0 million and \$4.3 million, respectively, in income as amortization of deferred gain on sale.

Gain on Sale of Properties. During the three months ended June 30, 2010, we sold our interest in several non-core properties for aggregate proceeds of \$7.6 million in cash, which resulted in a pre-tax gain on sale of \$1.9 million. During the three months ended June 30, 2009, we entered into a participation agreement with a privately held independent oil company covering acreage located primarily in the western portion of the Sanish field in Mountrail County, North Dakota. At the closing of the agreement, the private company paid us \$107.3 million, resulting in a pre-tax gain on sale of \$4.6 million.

Lease Operating Expenses. Our lease operating expenses during the second quarter of 2010 were \$67.7 million, a \$10.1 million increase over the same period in 2009. This higher amount of LOE in 2010 was related to increases of \$3.4 million in electric power costs, \$1.9 million in transportation charges 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 \$18.4 million in the second quarter of 2010, as compared to \$12.2 million in the second quarter of 2009, and this increase in workover activity primarily related to our two CO2 projects, which are evolving past the construction and start-up phases and moving into an ongoing maintenance and repair phase that involves a significantly higher number of producing and injection wells. Our lease operating expenses on a BOE basis increased from \$11.44 during the second quarter of 2009 to \$11.52 during the second quarter of 2010. The increase of 1% on a BOE basis was caused by increased LOE, partially offset by increased oil and natural gas production volumes.

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 second quarter of 2010 were \$26.1 million, an \$11.1 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 second quarter of 2010 and 2009 were 7.2% and 7.0%, respectively, of oil and natural gas sales. Our production tax rate for the second quarter of 2010 was greater than the rate for same period in 2009 mainly due to successful wells completed during the second half of 2009 and the first half of 2010 in the North Dakota Bakken area, which has an 11.5% production tax rate.

Table of Contents

Depreciation, Depletion and Amortization. Our DD&A expense decreased $5.7 million in 2010 as compared to the second quarter of 2009. The components of our DD&A expense were as follows (in thousands):

	Three Months Ended June 30,	
	2010	2009
Depletion	$92,245	$97,989
Depreciation	514	767
Accretion of asset retirement obligations	1,824	1,559
Total	$94,583	$100,315

DD&A decreased in the second quarter of 2010 primarily due to $5.7 million in lower depletion expense between periods. This net decrease in depletion of $5.7 million was the result of $22.2 million in lower depletion expense due to a decline in our depletion rate between periods, which effect was largely offset by $16.5 million in higher oil and gas volumes produced during the second quarter of 2010. On a BOE basis, our DD&A rate of $16.09 for the second quarter of 2010 was 19% lower than the rate of $19.93 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 half of 2010. These increases in proved reserves drove our DD&A rate substantially lower during the first half of 2010, as compared to our DD&A rate during the second quarter of 2009. This factor was partially offset by (i) $455.2 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 increased $4.7 million in the second quarter of 2010, as compared to the second quarter of 2009. The components of our exploration and impairment costs were as follows (in thousands):

	Three Months Ended June 30,	
	2010	2009
Exploration	$10,652	$6,178
Impairment	3,857	3,614
Total	$14,509	$9,792

Exploration costs increased $4.5 million during the second quarter of 2010 as compared to the same period in 2009 primarily due to an increase in G&G activity, partially offset by reduced rig termination fees recognized in the second quarter of 2010. G&G costs amounted to $6.4 million during the second quarter of 2010, as compared to $1.8 million during the same period in 2009. No rig termination fees were paid during the second quarter of 2010, while rig termination fees totaled $1.3 million during the second quarter of 2009. The impairment charges in the second quarter of 2010 and 2009 were primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties.

Table of Contents

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 June 30,	
	2010	2009
General and administrative expenses	$28,440	$22,687
Reimbursements and allocations	(13,038)	(12,405)
General and administrative expense, net	$15,402	$10,282

General and administrative expense before reimbursements and allocations increased $5.8 million to $28.4 million during the second quarter of 2010. The largest component of the increase related to $4.0 million in higher accrued distributions under the Plan between periods. Plan distributions increased 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 second quarter of 2010 as compared to the same period in 2009. In addition to these higher accrued Plan distributions, there was $2.3 million in additional employee compensation in the second quarter of 2010 related to higher stock compensation between periods, personnel hired during the past twelve months and general pay increases. The increase in reimbursements and allocations in the second 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 decreased from 5% for the second quarter of 2009 to 4% for the second quarter of 2010.

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

	Three Months Ended June 30,	
	2010	2009
Senior Subordinated Notes	$11,081	$10,977
Credit Agreement	1,963	4,940
Amortization of debt issue costs and debt discount	2,508	3,183
Other	437	482
Capitalized interest	(357)	(889)
Total	$15,632	$18,693

The decrease in interest expense of $3.1 million between periods was mainly due to lower borrowings outstanding under our credit agreement during the second quarter of 2010, which reduced the interest on our credit agreement by $3.0 million. The decrease in interest on our credit agreement was partially offset by lower amounts of capitalized interest between periods. Our weighted average debt outstanding during the second quarter of 2010 was $719.5 million versus $1,206.0 million for the second quarter of 2009. Our weighted average effective cash interest rate was 7.3% during the second quarter of 2010 compared to 5.6% during the second quarter of 2009.

Change in Production Participation Plan Liability. For the three months ended June 30, 2010, this non-cash expense was $4.7 million, an increase of $1.5 million as compared to the same period in 2009. This expense in 2010 represents the change in the vested present value of estimated future payments to be made after 2011 to participants under our Plan. Although payments take place over the life of the Plan's oil and gas properties, which for some properties is over 20 years, we expense the present value of estimated future payments over the Plan's five-year vesting period. This expense in 2010 and 2009 primarily reflected (i) changes to future cash flow estimates stemming from the volatile commodity price environment during each respective year, (ii) recent drilling activity and property acquisitions, and (iii) employees' continued vesting in the Plan. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

Table of Contents

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 as of March 31, 2009 and have elected to discontinue 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.

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

	Three Months Ended June 30,	
	2010	2009
Change in unrealized (gains) losses on derivative contracts	$(66,491)	$156,544
Realized cash settlement losses	2,995	3,988
Total	$(63,496)	$160,532

The change in unrealized (gains) losses on derivative contracts increased by $223.0 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 three months ended June 30, 2010 as compared to the upward shift in the same forward price curve during the three months ended June 30, 2009, and (ii) we averaged 16.7 MMBbls of crude oil hedged during the three months ended June 30, 2010, while we averaged 20.4 MMBbls of crude oil hedged during the three months ended June 30, 2009.

Income Tax Expense (Benefit). Income tax expense totaled $77.2 million for the second quarter of 2010, as compared to a $52.1 million income tax benefit for the second quarter of 2009. Our effective income tax rate increased from 35.9% for the second quarter of 2009 to 38.1% for the second quarter of 2010.

Net Income (Loss) Available to Common Shareholders. Net income (loss) available to common shareholders increased from a $93.2 million loss during the second quarter of 2009 to $119.9 million in income for the second quarter of 2010. The primary reasons for this increase include a 17% increase in equivalent volumes sold; a 40% increase in oil prices (net of hedging); a 46% increase in natural gas prices (net of hedging); higher unrealized commodity derivative gains; lower DD&A and interest expense. These positive factors were partially offset by lower gain on sale of properties and amortization of deferred gain on sale; higher production taxes, lease operating expenses, dividends paid on preferred stock, general and administrative expenses, exploration and impairment, Production Participation Plan expense and income taxes during the second quarter of 2010.

Liquidity and Capital Resources

Overview. At June 30, 2010, our debt to total capitalization ratio was 20.9%, we had $15.5 million of cash on hand and $2,460.3 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 half of 2010, we generated $440.1 million of cash provided by operating activities, an increase of $295.1 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 half of 2010, as well as increased production taxes and lease operating expenses during the first half of 2010 as compared to the same period in 2009. Cash flows from operating activities were used to finance net repayments under our credit agreement totaling $130.0 million, payment of preferred stock dividends totaling $10.8 million, $264.0 million of drilling and development expenditures paid in the first six months of 2010 and $34.0 million of cash acquisition capital expenditures. The following chart details our exploration and development expenditures incurred by region during the first six months of 2010 (in thousands):

32

Table of Contents

	Drilling and Development Expenditures (1)	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$182,052	$10,132	$192,184	63%
Permian Basin	83,047	5,058	88,105	29%
Mid-Continent	15,903	734	16,637	5%
Gulf Coast	3,306	3,759	7,065	2%
Michigan	3,270	32	3,302	1%
Total incurred	287,578	19,715	307,293	100%
Increase in accrued capital expenditures	(26,160)	-	(26,160)	
Total paid	$261,418	$19,715	$281,133	

(1) For purposes of this schedule, exploratory dry hole costs of $2.6 million are excluded from drilling and development expenditures as reported on the statement of cash flows and instead have been included in exploration expenditures above.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2010 capital budget for exploration and development expenditures is $830.0 million, which we expect to fund with net cash provided by our operating activities. Our 2010 capital budget of $830.0 million represents a significant increase from the $479.8 million incurred on exploration and development expenditures during 2009. This increased capital budget is due to increased discretionary cash flow resulting primarily from higher oil and natural gas prices experienced during the second half of 2009 and continuing into the first half of 2010, along with our available inventory of high-quality prospects for development and exploration. Although we have no specific budget for property acquisitions in 2010, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that if attractive acquisition opportunities arise or exploration and development expenditures exceed $830.0 million, we will be able to finance additional capital expenditures with cash on hand, cash flows from operating activities, borrowings under our credit agreement, issuances of additional debt or equity securities, or agreements with industry partners. Our level of exploration and development expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors. We believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs, dividend distributions and debt repayments; comply with our debt covenants; and meet other obligations that may arise from our oil and gas operations.

Credit Agreement. As of June 30, 2010, Whiting Oil and Gas Corporation ("Whiting Oil and Gas"), our wholly-owned subsidiary, had a credit agreement with a syndicate of banks, and this credit facility has a borrowing base of $1.1 billion with $1,069.6 million of available borrowing capacity, which is net of $30.0 million in borrowings and $0.4 million in letters of credit outstanding. The credit agreement provides for interest only payments until April 2012, when the agreement expires and all outstanding borrowings are due.

Table of Contents

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement, in each case which may reduce the amount of the borrowing base. Whiting Oil and Gas may, throughout the term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect at any given time. A portion of the revolving credit agreement in an aggregate amount not to exceed $50.0 million may be used to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours. As of June 30, 2010, $49.6 million was available for additional letters of credit under the agreement.

The credit agreement contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, incur liens and engage in certain other transactions without the prior consent of our lenders. The credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to 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 include the payment of dividends on our 6.25% convertible perpetual preferred stock, the credit agreement restricts our ability to make any dividend payments or distributions on our common stock or principal payments on our senior notes. We were in compliance with our covenants under the credit agreement as of June 30, 2010.

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

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

The indentures governing the notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation’s credit agreement. Additionally, the indentures governing the notes contain restrictive covenants that may limit our ability to, among other things, pay cash dividends, redeem or repurchase our capital stock or our subordinated debt, make investments or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of ours and our restricted subsidiaries taken as a whole and enter into hedging contracts. These covenants may potentially limit the discretion of our management in certain respects. We were in compliance with these covenants as of June 30, 2010. However, a substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants in the future.

Table of Contents

Schedule of Contractual Obligations. The table below does not include our June 30, 2010 Production Participation Plan liability of $75.1 million, since we cannot determine with accuracy the timing or amounts of future payments. The following table summarizes our obligations and commitments as of June 30, 2010 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods (in thousands):

	Payments due by period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (a)	$ 650,000	$ -	$ 400,000	$ 250,000	$ -
Cash interest expense on debt (b)	129,128	45,031	73,889	10,208	-
Asset retirement obligation (c)	81,477	9,261	2,355	8,034	61,827
Tax sharing liability (d)	23,301	1,857	3,320	18,124	-
Derivative contract liability fair value (e)	100,019	26,269	62,709	11,041	-
Purchasing obligations (f)	124,938	37,314	66,285	21,339	-
Drilling rig contracts (g)	75,732	39,698	36,034	-	-
Operating leases (h)	10,805	3,284	6,494	1,027	-
Total	$ 1,195,400	$ 162,714	$ 651,086	$ 319,773	$ 61,827

(a) Long-term debt consists of the 7.25% Senior Subordinated Notes due 2012 and 2013, the 7% Senior Subordinated Notes due 2014 and the outstanding borrowings under our credit agreement, and assumes no principal repayment until the due date of the instruments.

(b) Cash interest expense on the 7.25% Senior Subordinated Notes due 2012 and 2013 and the 7% Senior Subordinated Notes due 2014 is estimated assuming no principal repayment until the due date of the instruments. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the instrument due date and is estimated at a fixed interest rate of 2.4%.

(c) Asset retirement obligations represent the present value of estimated amounts expected to be incurred in the future to plug and abandon oil and gas wells, remediate oil and gas properties and dismantle their related facilities.

(d) Amounts shown represent the present value of estimated payments due to Alliant Energy based on projected future income tax benefits attributable to an increase in our tax bases. As a result of the Tax Separation and Indemnification Agreement signed with Alliant Energy, the increased tax bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay Alliant Energy 90% of the future tax benefits we realize annually as a result of this step up in tax basis for the years ending on or prior to December 31, 2013. In 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years.

(e) The above derivative obligation at June 30, 2010 consists of an $89.0 million fair value liability for derivative contracts we have entered into on our own behalf, primarily in the form of costless collars, to hedge our exposure to crude oil price fluctuations. With respect to our open derivative contracts at June 30, 2010 with certain counterparties, the forward price curve for crude oil generally exceeded the price curve that was in effect when these contracts were entered into, resulting in a derivative fair value liability. If current market prices are higher than a collar's price ceiling when the cash settlement amount is calculated, we are required to pay the contract counterparties. The ultimate settlement amounts under our derivative contracts are unknown, however, as they are subject to continuing market risk and commodity price volatility. The above derivative obligation at June 30, 2010 also consists of an $11.0 million payable to Whiting USA Trust I (the "Trust") for derivative contracts that we have entered into but have in turn conveyed to the Trust. Although these derivatives are in a fair value asset position at quarter end, 75.8% of such derivative assets are due to the Trust under the terms of the conveyance.

(f) We have two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement expiring in December 2014, whereby we have committed to buy certain volumes of CO2 for use in enhanced recovery projects in our Postle field in Oklahoma and our North Ward Estes field in Texas. The purchase agreements are with different suppliers. Under the terms of the agreements, we are obligated to purchase a minimum daily volume of CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. The CO2 volumes planned for use in the enhanced recovery projects in the Postle and North Ward Estes fields, however, currently exceed the minimum daily volumes stipulated in these take-or-pay purchase agreements. Therefore, we expect to avoid any payments for deficiencies.

(g) We currently have six drilling rigs under long-term contract, of which two drilling rigs expire in 2010, one in 2011, two in 2012 and one in 2013. All of these rigs are operating in the Rocky Mountains region. As of June 30, 2010, early termination of the remaining contracts would require termination penalties of $46.6 million, which would be in lieu of paying the remaining drilling commitments of $75.7 million. No other drilling rigs working for us are currently under long-term contracts or contracts that cannot be terminated at the end of the well that is currently being drilled. Due to the short-term and indeterminate nature of the time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(h) We lease 116,100 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, and an additional 46,700 square feet of office space in Midland, Texas expiring in 2012.

Table of Contents

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

New Accounting Pronouncements

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, refer to the Adopted and Recently Issued Accounting Pronouncements footnote in the Notes to Consolidated Financial Statements.

Critical Accounting Policies and Estimates

Information regarding critical accounting policies and estimates is contained in Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

Effects of Inflation and Pricing

We experienced increased costs during 2007 and 2008 due to increased demand for oil field products and services, while costs in 2009 remained relatively consistent with 2008. During the first half of 2010, we began to experience moderate cost increases, as the demand for oil field products and services has begun to rise from 2009 levels. The oil and gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and not adjust downward in proportion to prices. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Forward-Looking Statements

This report contains statements that we believe to be "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we "expect," "intend," "plan," "estimate," "anticipate," "believe" or "sho the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements.

Table of Contents

These risks and uncertainties include, but are not limited to: declines in oil or natural gas prices; impacts of the global recession and tight credit markets; our level of success in exploitation, exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures, including our ability to obtain CO2; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; risks related to our level of indebtedness and periodic redeterminations of the borrowing base under our credit agreement; our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget; our ability to obtain external capital to finance exploration and development operations and acquisitions; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete potential asset dispositions; the impacts of hedging on our results of operations; failure of our properties to yield oil or gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and gas industry in the regions in which we operate; risks arising out of our hedging transactions; and other risks described under the caption "Risk Factors" in our Annual Report on Form 10-K for the fiscal year ended December 31, 2009. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our quantitative and qualitative disclosures about market risk for changes in commodity prices and interest rates are included in Item 7A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2009 and have not materially changed since that report was filed.

Our outstanding hedges as of July 1, 2010 are summarized below:

Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	07/2010 to 09/2010	680,000	$62.56/$85.87
Crude Oil	10/2010 to 12/2010	665,000	$62.62/$87.93
Crude Oil	01/2011 to 03/2011	360,000	$47.30/$88.23
Crude Oil	04/2011 to 06/2011	360,000	$47.30/$88.23
Crude Oil	07/2011 to 09/2011	360,000	$47.30/$88.23
Crude Oil	10/2011 to 12/2011	360,000	$47.30/$88.23
Crude Oil	01/2012 to 03/2012	330,000	$47.46/$90.19
Crude Oil	04/2012 to 06/2012	330,000	$47.46/$90.19
Crude Oil	07/2012 to 09/2012	330,000	$47.46/$90.19
Crude Oil	10/2012 to 12/2012	330,000	$47.46/$90.19
Crude Oil	01/2013 to 03/2013	290,000	$47.67/$90.21
Crude Oil	04/2013 to 06/2013	290,000	$47.67/$90.21
Crude Oil	07/2013 to 09/2013	290,000	$47.67/$90.21
Crude Oil	10/2013	290,000	$47.67/$90.21
Crude Oil	11/2013	190,000	$47.22/$85.06

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I (the “Trust”), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 1,164 MBbls of crude oil and 4,382 MMcf of natural gas from 2010 through 2012, have been conveyed to the Trust, and therefore such payments will be included in the Trust’s calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. Our retention of 10% of these net proceeds combined with our ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, while we retain 24.2%, of future economic results of such hedges. No additional hedges are allowed to be placed on Trust assets.

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

Table of Contents

Conveyed to Whiting USA Trust I

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	07/2010 to 09/2010	42,966	$76.00/$134.89
Crude Oil	10/2010 to 12/2010	41,924	$76.00/$135.11
Crude Oil	01/2011 to 03/2011	40,978	$74.00/$139.68
Crude Oil	04/2011 to 06/2011	40,066	$74.00/$140.08
Crude Oil	07/2011 to 09/2011	39,170	$74.00/$140.15
Crude Oil	10/2011 to 12/2011	38,242	$74.00/$140.75
Crude Oil	01/2012 to 03/2012	37,412	$74.00/$141.27
Crude Oil	04/2012 to 06/2012	36,572	$74.00/$141.73
Crude Oil	07/2012 to 09/2012	35,742	$74.00/$141.70
Crude Oil	10/2012 to 12/2012	35,028	$74.00/$142.21
Natural Gas	07/2010 to 09/2010	167,583	$6.00/$14.00
Natural Gas	10/2010 to 12/2010	162,997	$7.00/$14.20
Natural Gas	01/2011 to 03/2011	157,600	$7.00/$17.40
Natural Gas	04/2011 to 06/2011	152,703	$6.00/$13.05
Natural Gas	07/2011 to 09/2011	148,163	$6.00/$13.65
Natural Gas	10/2011 to 12/2011	142,787	$7.00/$14.25
Natural Gas	01/2012 to 03/2012	137,940	$7.00/$15.55
Natural Gas	04/2012 to 06/2012	134,203	$6.00/$13.60
Natural Gas	07/2012 to 09/2012	130,173	$6.00/$14.45
Natural Gas	10/2012 to 12/2012	126,613	$7.00/$13.40

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases above the ceiling. For the crude oil contracts listed in both tables above, a hypothetical $5.00 per Bbl change in the NYMEX forward curve as of June 30, 2010 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $43.7 million. For the natural gas contracts listed above, a hypothetical $1.00 per Mcf change in the NYMEX forward curve as of June 30, 2010 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $0.6 million.

We have various fixed-price sales contracts with end users for a portion of the natural gas we produce in Colorado, Michigan and Utah. Our estimated future production volumes to be sold under these fixed-price contracts as of July 1, 2010 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	07/2010 to 09/2010	742,333	$5.33
Natural Gas	10/2010 to 12/2010	825,000	$5.29
Natural Gas	01/2011 to 03/2011	779,000	$5.30
Natural Gas	04/2011 to 06/2011	786,667	$5.30
Natural Gas	07/2011 to 09/2011	772,333	$5.30
Natural Gas	10/2011 to 12/2011	772,333	$5.30
Natural Gas	01/2012 to 03/2012	577,000	$5.30
Natural Gas	04/2012 to 06/2012	461,333	$5.41
Natural Gas	07/2012 to 09/2012	465,667	$5.41
Natural Gas	10/2012 to 12/2012	398,667	$5.46

Natural Gas	01/2013 to 03/2013	360,000	$5.47
Natural Gas	04/2013 to 06/2013	364,000	$5.47
Natural Gas	07/2013 to 09/2013	368,000	$5.47
Natural Gas	10/2013 to 12/2013	368,000	$5.47
Natural Gas	01/2014 to 03/2014	330,000	$5.49
Natural Gas	04/2014 to 06/2014	333,667	$5.49
Natural Gas	07/2014 to 09/2014	337,333	$5.49
Natural Gas	10/2014 to 12/2014	337,333	$5.49

Table of Contents

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), our management evaluated, with the participation of our Chairman, President and Chief Executive Officer and our Chief Financial Officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of June 30, 2010. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President and Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures were effective as of June 30, 2010 to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There was no change in our internal control over financial reporting that occurred during the quarter ended June 30, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2009. No material change to such risk factors has occurred during the six months ended June 30, 2010.

Item 6. Exhibits

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

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on this 30th day of July, 2010.

WHITING PETROLEUM CORPORATION

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

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

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

Table of Contents

EXHIBIT INDEX

Exhibit Number	Exhibit Description
(31.1)	Certification by the Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Written Statement of the Chairman, President and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Written Statement of the Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
(101)	The following materials from Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 are furnished herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of June 30, 2010 and December 31, 2009, (ii) the Consolidated Statements of Income for Three and Six Months Ended June 30, 2010 and 2009, (iii) the Consolidated Statements of Cash Flow for the Six Months Ended June 30, 2010 and 2009, (iv) the Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Six Months Ended June 30, 2010 and 2009, and (v) Notes to Consolidated Financial Statements.